Master's Thesis - Energy Science

Comparing hydrogen networks and electricity grids for transporting offshore wind energy to shore in the North Sea region. A spatial network optimisation approach.

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Preface

From August 2021 to July 2022 I undertook an internship with TNO in the Subsurface Energy Transition Team, completing two projects. The first phase was completing data collection on the North Sea, while the second phase (this thesis) was developing a hydrogen network optimisation model. This marks the end of my time at TNO. I would like to thank everyone at TNO and the North Sea Energy programme for giving me the platform to frame my own project and deepen my knowledge on offshore wind and hydrogen in the North Sea. Specifically, I would like to thank Durgesh Kawale for his supervision over the last year, and always finding a way to dissect and re-frame a problem in an understandable way. Also thanks to my other, ever-enthusiastic supervisor, Joris Koornneef for consistently bringing great energy to your work.

From Utrecht University, I would like to express my gratitude Jan Wiegner for your support, overall friendliness, and readiness to help. You made this thesis very enjoyable. Thank you to Gert Jan Kramer for steering the research from a broad, holistic view, and providing useful criticism. I would also like to express my gratitude for Patrycja Enet from the European MSP Platform, the knowledge and liveliness you brought was much appreciated.

I also wish to thank my friends and fellow students. Specifically Noelia, thank you for listening to me speak about hydrogen for a year, and cleverly distracting me when I needed a break from the work. Ruben, your ability to understand my coding problem and near-instantly send a solution is unmatched. Thank you. And lastly, thanks to David from TU Delft. It was a pleasure to discuss the similarities and intricacies of our work over the last few months.

This thesis finalises my time as an Energy Science master student at Utrecht University. I have enjoyed every second of it. Please enjoy the read.

Abstract

In the North Sea (NS), offshore wind farm (OWF) capacity is expected to explode in the coming years to support decarbonisation goals. To bring these vast amounts of energy to shore, offshore hydrogen production and transportation to shore via pipelines is seen to be a plausible solution. Previous literature has investigated spatially explicit hydrogen networks in the Dutch extended economic zone (EEZ). However, capacitated networks were not considered. This research builds on the previous literature and addresses the following: 1) the effects of spatial complexity and reuse of oil & gas (O&G) infrastructure on networks, 2) the properties of a fully interconnected NS network and 3) a comparison between hydrogen networks and electricity grids.

A three-part model was devised; creating cost surfaces, generating candidate networks and finding optimal network layouts. A cost surface is created using PyQGIS, assigning weighing values to spatial uses in the NS. Using these cost surfaces, candidate networks (PyQGIS) are generated by running least cost paths between sources (offshore hydrogen supply points), sinks (onshore hydrogen demand points), and existing network infrastructure in the NS. Finally, the optimal network layout model (Python) is used to find capacitated infrastructure networks. Costs are calculated in post-processing, finding the network and system levelised costs of hydrogen (LCOH).

The results show that including spatial complexity increases capacity-lengths by 50% - 90% compared to a greenfield approach, as the network routes around high 'cost' spatial uses. Reusing infrastructure leads to cost savings of 40% for hydrogen networks, as 84% of the network consists of reusing existing O&G infrastructure at low costs. Smaller savings are seen for electricity grids (5%), as only cable corridors can be reused, which do have a low cost saving. Interconnected networks are 38% (hydrogen) to 58% (electricity) larger when compared to isolated networks. Careful planning of interconnection is required to avoid overinvestments in capacity between countries. The interconnected network costs of hydrogen networks range between 14 - 21 B€, while electricity grids range between 87 - 116 B€. In a system context, the difference in LCOH between all scenarios is small, between 1.95 and 2.15 €/kg, suggesting that offshore hydrogen is competitive in 2040.

Based on this study, recommendations can be given. Firstly, extending the scope of the onshore onshore hydrogen backbones to offshore can provide significant cost savings by reusing infrastructure. To facilitate this, regulatory support is needed for integrating O&G infrastructure with OWF and energy islands, as it is currently lacking. Investigating the interactions between spatial uses and network planning can feed marine/maritime spatial planning in order to define large interconnected corridors across EEZs for future installations of infrastructure. These corridors could allow sensible interconnection between countries, avoiding unharmonised networks. Finally, future research should widen the optimisation scope to consider onshore connections and dynamic hydrogen supply and demand, leading to more accurate representations of offshore connections in the NS, while avoiding unnecessary costs in overcapacitated connections.

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Abbreviations

GHG	Green-house gas
EU	European Union
NS	North Sea
BE	Belgium
NL	(the) Netherlands
DE	Germany
DK	Denmark
NO	Norway
UK	(the) United Kingdom
O&G	Oil and gas
OWF	Offshore wind farm
EEZ	Extended economic zone
GW	Giga-watt (10^9 W)
HVDC	High voltage direct current
HVAC	High voltage alternating current
US	United States
EHB	European Hydrogen Backbone (project)
(Q)GIS	(Quantum) Geographical Information Systems
FCEV	Fuel cell electric vehicle
CCS	Carbon capture and storage
P2H	Power to hydrogen
NSWPH	North Sea Sind Power Hub
LCP	Least cost path
ONL	Optimal network layout
MST	Minimal spanning tree
MCST	Minimum cost spanning tree
MSP	Marine/maritime spatial plan(ning)
TSO	Transmission system operator
OTNR	Offshore Transmission Network Review
TWh	Terra-watt hour (10^{12} Wh)
yr	Year
NUTS	Nomenclature of Territorial Units for Statistics
RSQ	Research sub question
LCOH	Levelized cost of hydrogen
MWh	Mega-watt hour (10^6 Wh)
kg	Kilogram
H2	Hydrogen
km	Kilometre
NSE	North Sea Energy

1 Introduction

Countries are reducing their green-house gas (GHG) emissions to slow down global warming. In the European Union (EU), recent legislation details a 55% reduction in GHG emissions by 2030 and 100% by 2050 [1, 2]. The United Kingdom (UK) and Norway (NO) also aim to reduce emissions by 100% and 90-95% respectively by 2050 [3, 4]. To realise these goals, it is widely agreed that rapid development, commercialisation and innovation of renewable, low-carbon energy sources and storage is needed [5]. More recently, following Russia's invasion of Ukraine in early 2022, extra pressure has been placed on accelerating short term decarbonisation goals such as through the RePower EU plan [6]. Decarbonisation has now become a geopolitical priority as well as a climate priority.

In Europe, the North Sea (NS) is a good place for this. Historically, the NS has been used for oil and gas (O&G) exploration, with over 1300 installations in use [7]. Now, it is host to a growing amount of offshore wind farms (OWF). As shown in Figure 1, the NS is split into the extended economic zones (EEZ) of 8 countries resulting in contesting stakeholders and spatial uses. Therefore, there is a need for integrated cross-sectoral solutions and legislation [8, 9, 10, 11].

Wind energy from OWF has been identified as an integral part of these solutions [12, 13]. The EU have set goals of increasing the capacity of OWF by 2500% from 12 GW to 300 GW by 2050 [13]. The recent Esbjerg Declaration, which defined the NS as "the Green Power Plant of Europe", states that 150 GW of offshore wind will be installed by 2050 in Belgium (BE), the Netherlands (NL), Germany (DE) and Denmark (DK) [14]. In the whole of the NS, it is expected to be even greater, between 180-255 GW [15, 16]. A lot of space will be required for this, which means that OWF are trending further offshore [11]. Complications arise when bringing large amounts of energy to land, namely;

- High infrastructural costs of HVDC cables to transport the energy to land and reinforcement of the onshore grid to accommodate the increasing load.
- Energy losses through wind energy overproduction leading to electricity curtailment transporting electricity via cables for long distances.

Converting offshore electricity production from OWF to hydrogen via electrolysis and transporting it to land via pipelines can act as a solution to alleviate some of these complications. However, this topic is contended in the literature. Purely from a transport perspective, it is shown that hydrogen pipelines are less costly than HVDC cables over very long distances ($>$ 740 km) [17, 18, 19]. However, Semeraro and Taieb & Shabaan [18, 19] assume that hydrogen is converted back to electricity at the end of its transportation, which incurs extra energy losses. On the other hand, Franco et al. [20] find that when hydrogen is sold to end users, pipeline costs become less than HVDC cables at distances between 150-250 km from land. The study concludes that offshore

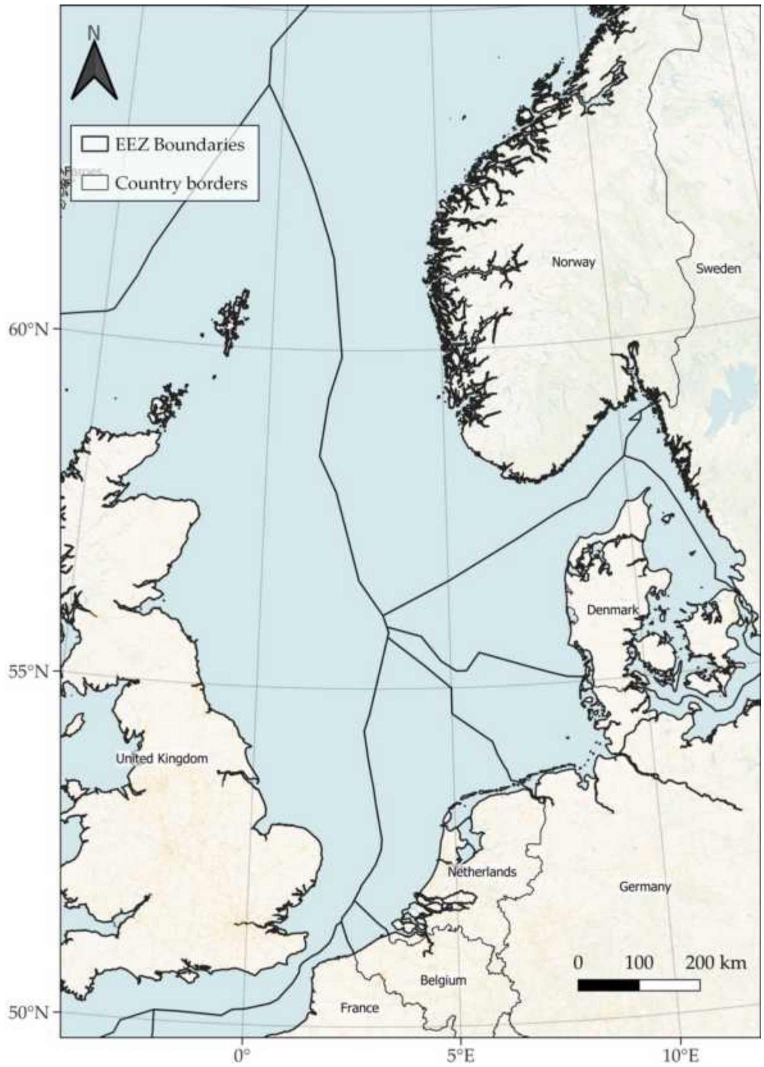

Figure 1: The North Sea (NS), with the Extended Economic Zone (EEZ) of the 8 bordering countries.

hydrogen production with pipeline transmission is more beneficial than HVDC transmission with onshore hydrogen production.

Looking from a system cost perspective, Van der Veer et al. and Van Schot and Jepma [21, 16] find that offshore hydrogen may be feasible via energy islands, when the distance from shore increases above 100 km and the wind farm capacity connected to the island is on the order of several GW. When considering market dynamics, Meier [22] finds that costs of hydrogen from offshore are too high to be competitive . However, as the author states, the study mostly considers current efficiencies and costs, not taking into account the future learning. More recent studies see benefits when hydrogen is sold directly to end users, as opposed to converting back to electricity [23, 24]. Singlitico et al. [25] find a similar conclusion in Denmark, and specify that distances above 100 km from shore are optimal.

When comparing compressed hydrogen to other energy carriers or other forms of hydrogen (synthetic natural gas, methanol, ammonia and liquified hydrogen), it is seen that that compressed hydrogen is the most beneficial method to transport the energy to shore [26, 27, 28]. Lastly, when looking at offshore hydrogen production in a whole energy system perspective, there is significant offshore electrolyser capacity seen. Looking at the Dutch energy system, Van Stralen et al. [29] found that electrification of OWF energy to shore will remain dominant, but offshore hydrogen production will be in the range of 16 – 80 TWh/yr in 2050. This scope can be expanded to the whole of the NS region, where Gea-Bermúdez et al. [30] similarly conclude that offshore hydrogen production will remain limited, and that the majority will be produced onshore. Nevertheless, in every scenario modelled in this study, a minimum of 4 GW of offshore electrolyser capacity is seen. Additionally, when offshore salt cavern storage is included in the modelling, offshore electrolyser capacity increases to 64 GW, representing 10% of total hydrogen production by 2050. Salt caverns are already utilised for hydrogen storage in the UK and US and have been shown to be a very likely candidate for hydrogen storage in Europe in the future [31, 32, 33].

As a summary, the literature shows that a case exists for offshore hydrogen production. However, a common requirement seen in the studies is the need for a sufficient hydrogen demand and/or price. A significant future hydrogen demand is likely to be realised, due to the diverse (future) uses of hydrogen in many sectors such as transportation, heating, industry, power and agriculture [34, 35]. These uses of hydrogen have been known for decades [36, 37], yet it hasn't gained momentum until recent years, where investments of around $ 500 Billion have been made up to 2030 [38]. In the EU specifically, the Hydrogen Strategy is aiming towards 40 GW of renewable hydrogen production by 2030 [39]. This is complemented by large scale transportation plans such as the European Hydrogen Backbone project (EHB), which envisages a broad interconnected hydrogen transportation network throughout Europe, where 69% of the backbone is based on repurposing existing O&G infrastructure [40, 41]. The exact future demand is unknown, due to the highly uncertain extent of hydrogen's role in different sectors [35]. However, it is expected to have a significant role in the order of several hundred to thousands of TWh/yr [42, 43, 44, 45].

In practice, some offshore hydrogen production projects are already underway. In the NL, the Poshydon project is piloting a 1 MW electrolyser in the Dutch NS [46]. Recently, a new pilot project; H_2OpZee was announced by RWE and Neptune Energy, where 300-500 MW of electrolyser capacity will be built in the Dutch EEZ [47]. In DE, the AquaVentus, (2021) project is planning for 10 GW of offshore hydrogen production by 2035 [48]. In Scotland (UK), the HT1 project will trial offshore electrolysis within wind turbines [49].

This body of literature brings the following starting research question:

How does offshore hydrogen production and transportation become an economically attractive option compared to onshore production when considering the entire North Sea basin?

A literature review is conducted to develop this research question.

2 Literature review

2.1 Gaps in offshore power to hydrogen studies

From the literature mentioned in the introduction, two common gaps can be identified. Firstly, most studies neglect the potential to reuse O&G infrastructure for hydrogen. Secondly, only singular, isolated, point-to-point offshore hydrogen projects are researched, disregarding the opportunities of networks and interconnection. The following sections argue why this should be taken into account.

O&G infrastructure is widely developed in the NS, with thousands of pipelines and platforms present, as shown in Figure 2. Hydrogen can be used in the existing gas grid through blending, or through complete repurposing of the pipeline [50]. Abbas et al. [51] find that, without modifying existing pipelines, hydrogen may be blended up to 40% in existing gas flows, without exceeding the erosional velocity of the pipe. However, this may lead to peculiar flow behaviours, which would require improved gas quality tracking on pipelines [52, 53]. Additionally, blending may be limited to lower amounts if existing natural gas compressors are used [54, 50].

For higher amounts of blending, or transporting pure hydrogen, O&G infrastructure needs to be modified further [51]. The recent Re-Stream report by DNV and Carbon Limits collated data from 65 pipeline operators throughout Europe, representing half of the offshore pipeline length and 30% of onshore pipeline length. Their report concluded that most offshore pipelines can be reused for hydrogen, with a minimum reusable amount of 2-25% [55]. Repurposing pipelines for hydrogen can bring significant cost savings, at 10-40% of the costs of constructing new hydrogen pipelines [55, 56, 41].

Quarton and Samsatli, [57] identify 25 projects where hydrogen is blended into gas grids. An example of an offshore project which does this is the PosHydon pilot, where the created hydrogen is blended into the gas grid (albeit at very low levels <1%) [58, 46]. There are also broad plans and projects to completely repurpose pipelines for hydrogen, such as the EHB, which has recently increased its scope to the NS [59]. Additionally, public and private projects are also being undertaken in many NS-region countries to do this, such as the UK [60, 60, 61], NL [62] and DE [63, 64].

In the instances where reuse of offshore natural gas pipelines is included in energy system modelling, offshore hydrogen production becomes increasingly feasible, as is shown by Leerling [65]. He investigated the NS energy system using Powerfys, finding that cost savings are seen with offshore hydrogen production. However, it was not spatially explicit and did not consider construction of new hydrogen pipelines. Another master thesis on a European hydrogen network by Huisman [66] included some spatial detail of the existing natural gas grid. However, this study was specifically completed on the European mainland, and disregarded the UK and the NS, where much hydrogen could be produced and traded [30, 67]. Additionally, other spatial complexities besides O&G infrastructure were not considered. Literature on electricity grids shows

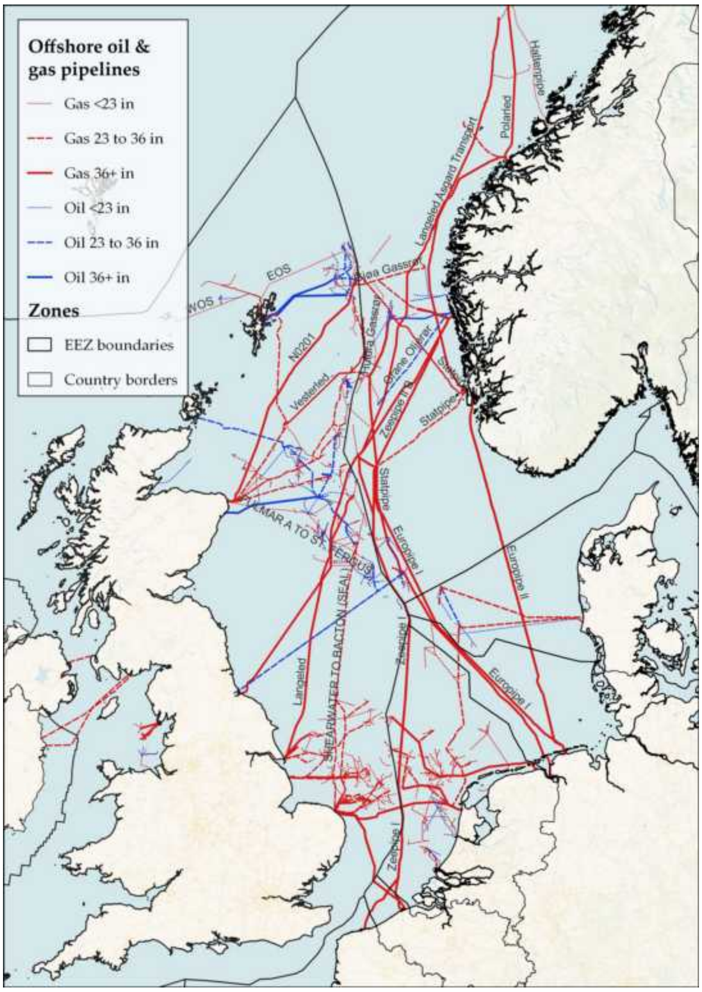

Figure 2: Offshore O&G pipeline networks in the NS, shown with substance and diameter.

that in comparison to point to point (radial) grids, interconnected electricity grids in the NS are cheaper, promote more OWF investment, provide system flexibility and decrease wind energy curtailment [68, 69, 70, 71, 72, 73, 74, 75, 76, 77, 78]. This concept is supported by the EU through the Interreg program [79]. However, in practice, realising an interconnected grid in the NS may be problematic due to the unharmonized regulatory constraints and legislation between different countries [80, 72, 81].

Although this is not directly comparable to the gas grid, it could be argued that an interconnected hydrogen network between countries could be more beneficial than an isolated topology, bringing benefits such as reliability, system flexibility and offshore hydrogen trading. This concept is reinforced by the matured topology of the O&G pipeline network as shown in Figure 2 and by ENTSOG [82], where interconnection between countries is seen. Yet, a comparison of interconnected against isolated hydrogen networks has not been studied in the literature. In practice, this concept is also supported by projects such as the hub-and-spoke project by the North Sea Wind

Power Hub (NSWPH), where Energinet, Tennet and Gasunie (the Transmission System Operators (TSO) of DK, DE and NL) envisage several offshore energy hubs, connecting hydrogen power cables and hydrogen pipelines between several countries [81]. Furthermore, it is also supported by the North Sea Energy (NSE) and One North Sea projects, which are led by TNO [83, 84].

2.2 Hydrogen networks

Onshore hydrogen networks have been studied extensively. Several reviews of hydrogen supply chain studies are available [85, 86, 87, 88]. These reviews have identified several important points and gaps in the current literature:

- Lack of studies introducing the concept of risk, (deep & epistemic) uncertainty and robust optimisation in creating a hydrogen supply chain network.
- Lack of studies looking at international hydrogen supply chains.
- Most studies focus on cost minimisation, less optimise for safety or societal benefit.
- Linking optimisation with GIS should be done to increase spatial detail.
- Hydrogen demand is nearly always calculated through estimating a future FCEV market share.

Next to this, a review of 17 papers which specifically include hydrogen pipelines was completed [89, 90, 91, 92, 93, 94, 95, 96, 97, 98, 99, 100, 101, 102, 103, 104, 105]. Similar to the hydrogen supply chain reviews it was found that:

- Nearly all studies formulate hydrogen demand as a fuel-cell electric vehicle (FCEV) market share.
- Most studies are deterministic, with a not much attention given to the elements of risk and uncertainty.
- All studies besides by Samsatli & Samsatli [100] only optimise for cost minimisation, with no other goal.

Additionally, it was found that spatial complexities other than distance are largely unaccounted for, besides by Johnson and Ogden, [93] where changes in elevation is considered in the optimisation.

2.3 Spatial network optimisation

In other network optimisation literature, spatial aspects are an important input. These are spatial aspects other than geometric distance, such as geological features (slope, aspect), as well as land-use features such as nature areas, rights of way, restricted areas and so forth. These spatial complexities can be assigned cost values and, through that, create a cost surface, where the cost represents the cost of laying down a infrastructural pathway through the area [106]. It is seen in multiple domains such as planning of roads [107], waterways [108], archaeological tracing [109], residential heat [110] and pipelines. Specifically for pipelines, it has been done extensively for modelling of carbon capture and storage (CCS) networks [111, 112, 113, 114, 115, 116, 117, 118, 119] and gas pipelines [120, 121]. Additionally, it has also been done for power cables [122, 123, 124, 125].

For hydrogen networks, these specific spatial complexities are often neglected. Coleman et al. [126] created a power to hydrogen (P2H) suitability map based on protected areas, streets, wind farms and industry, but did not create a network. Two previous projects within TNO [127, 128] have used this approach for mapping hydrogen networks in the Dutch EEZ in the NS (see Figure 3). Such modelling is very important in the NS, as many stakeholders and spatial uses coexist, as mentioned previously. However, these studies are limited to the Dutch EEZ of the NS, and do not consider the energy flows within the network. I.e., no changing capacities are assigned to pipelines and no supply and demand of hydrogen is considered. This study aims to build on these previous projects.

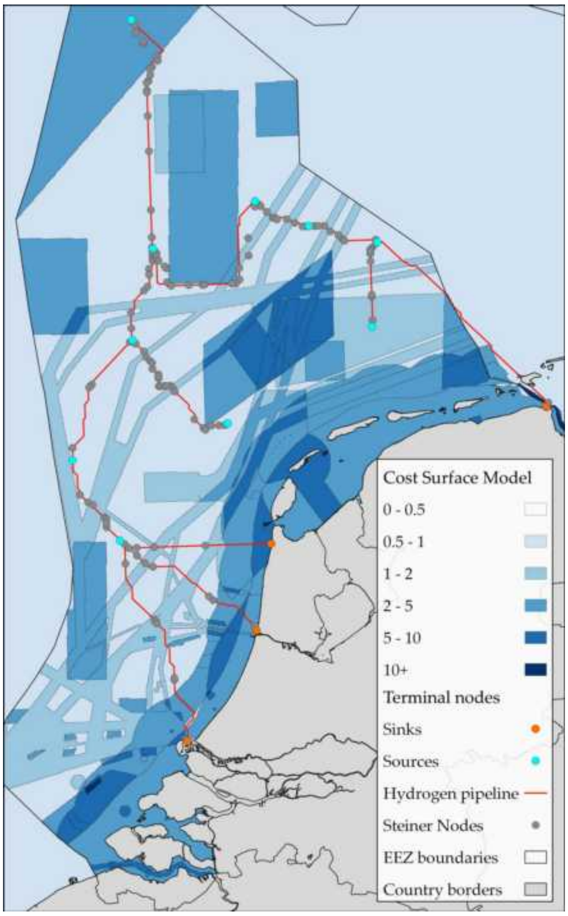

Figure 3: Cost surface, hydrogen pipeline network and hydrogen supply (Sources) and demand (Sinks) nodes in the Dutch EEZ. Adapted from Boerhout [127].

2.4 Research gaps

Thus, considering the previously mentioned gaps in the offshore P2H literature, as well as the gaps mentioned in hydrogen supply chain modelling, this study will attempt to address the following:

- Investigate the differences in cost and network design between electricity grids and hydrogen networks.
- Including the reuse of O&G infrastructure in hydrogen network modelling, specifically in the NS region.
- Investigating the difference between isolated and interconnected hydrogen networks in the NS.
- Including spatial complexities in hydrogen network optimisation modelling.

2.5 Research questions

Based on the above literature and the identified gaps, the previously defined research question can be further developed to:

Considering spatial complexities and uncertainties, what are the most suitable energy network configurations for producing hydrogen in the North Sea region in 2040?

Which can be broken up into:

1. *How do spatial complexities and the reuse of existing infrastructures affect energy infrastructure routing and network costs when compared to a greenfield approach?*
2. *How does the size and investment costs of the network vary for countries bordering the NS when interconnected via their offshore energy networks, compared to an isolated approach?*
3. *How do the spatial and economic properties change between an interconnected hydrogen network compared with an interconnected electricity grid?*

2.6 Report structure

The remainder of the report is structured in the following; Section 3 provides a theoretical background on spatial network optimisation. Section 4 explains the methodology. Section 5 provides the results, while Section 6 discusses the results and limitations. Lastly, Section 7 gives the conclusions and recommendations. Additional information is found in the Appendix.

3 Theoretical background

The work herein is primarily based on QGIS and Python, developing and merging three different sub-models for one purpose. The Cost Surface Model and SMTAtlas model were received from TNO and created by Boerhout [127]. The Optimal Network Layout model (ONL) is created by Heijnen et al [129]. These models make use of a few main concepts; cost surfaces, least cost pathways and network optimisation. These are further introduced below.

3.1 Cost surface

A cost surface can be created by assigning values to spatial data and combining them into a grid or surface of values. The values assigned to different spatial data can reflect a number of different costs such as monetary costs, environmental costs or societal costs (sources). This technique is often used as a multi-criteria analysis when there are several different spatial phenomena present, such as planning of OWF (source). Figure 4 shows an example of creating a cost surface.

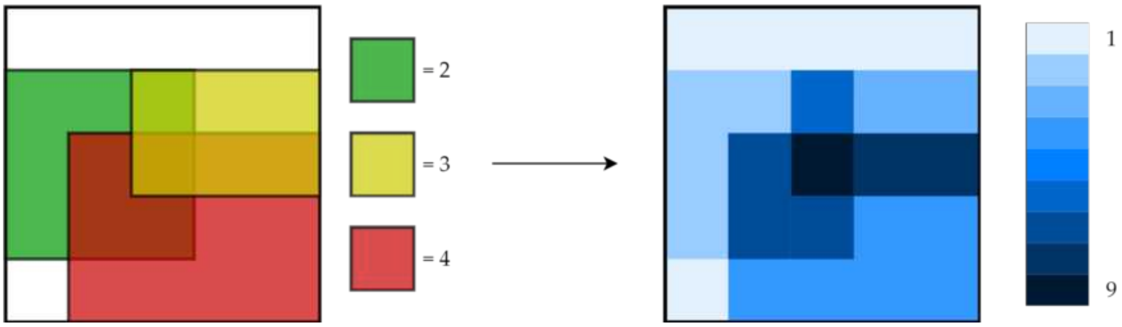

Figure 4: Fictitious example of a cost surface, created from three spatial data sets.

3.2 Least cost pathways

Least cost pathways (LCPs) often make use of a cost surface to find the lowest cost route from one point to another. Here, the cost is what is specified in the previous cost surface. The original algorithm for LCPs is based on Dijkstra's algorithm, which is an iterative algorithm to find the shortest distance between a set of nodes [130]. For example, in Figure 5 below, a set of nodes is given on the left, where an imaginary length is given between the nodes on the edges (connecting lines). The shortest path between node A and node E must be found. The algorithm iterates through all possible pathways and finds the shortest path. This is denoted by the red line on the right of the figure. The pathway is A - B - E with a total length of 4. Dijkstra's algorithm can be used in conjunction with cost surfaces, where the distance value between nodes can be changed to a cost value. This then becomes a LCP algorithm. However, it can become a much slower process. Each grid cell within the cost surface becomes a node, storing the cost of that specific grid cell.

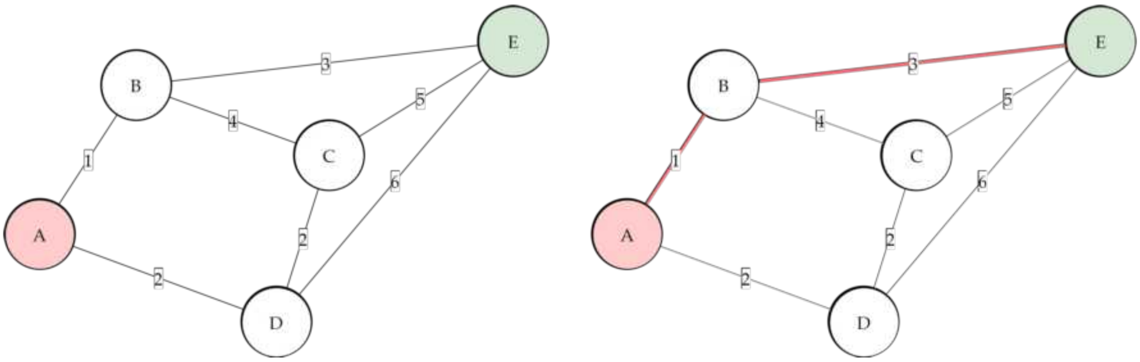

Figure 5: Fictitious example of Dijkstra's shortest path algorithm.

This means that the algorithm must iterate through many more possible pathways. Therefore, the resolution of the cost surface determines the number of possible pathways from one target node to the other, and in turn determines the total time it takes for the algorithm to find an answer. Using the same cost surface as from Figure 4, a LCP can be shown in Figure 6 below. From left to right, the cost surface cells are converted to a nodes with certain cost values. The LCP algorithm then iterates (two example iterations shown in grey) through the possible pathways to find the least cost pathway (red line).

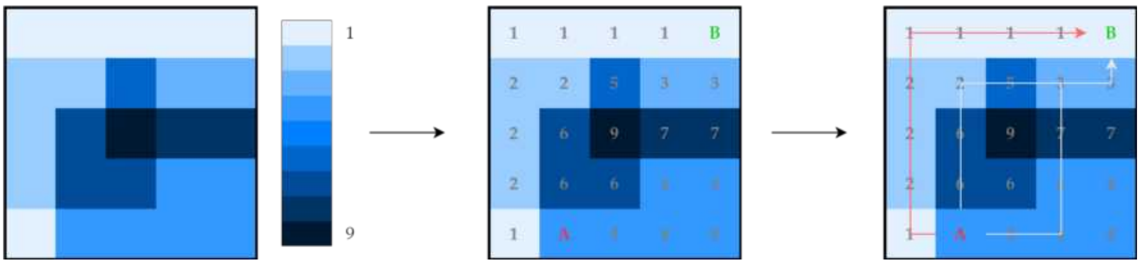

Figure 6: Fictitious example of a LCP from a starting node A to end node B. The red line shows the least cost path, whereas the grey lines show examples of the iterations which the algorithm must make (not exhaustive).

3.3 Network optimisation

Heijnen et al., (2020) define three types of network optimisation modelling: graph theory, mixed integer (non-) linear programming (MI(N)LP) and ant colony optimisation (ACO) [129]. In this study, the graph theory approach is followed, which is argued by Heijnen et al. [129] and Huisman [66] to be the most useful methodology to model energy networks. Differently to producing LCPs, which connects two nodes with each other, graph theory connects multiple nodes. This creates a set of connections (edges) and points (nodes), which make up the network. The optimisation procedure is often done in order to minimise the distance or a user-defined cost.

Using the example nodes from Figure 5, the network can be optimised to create a minimum spanning tree, which connects all nodes, as is seen in Figure 7a and 7b below. This can be more complex, by defining sources and sinks with specific supply and demands, as is seen in c. This can be optimised to create a capacitated network, as shown in d. In the model from Heijnen et al. [129] it is possible to define a routing network where the optimisation space is forced to only consider specific connections. This routing network is highlighted in e below, where f shows the outcome.

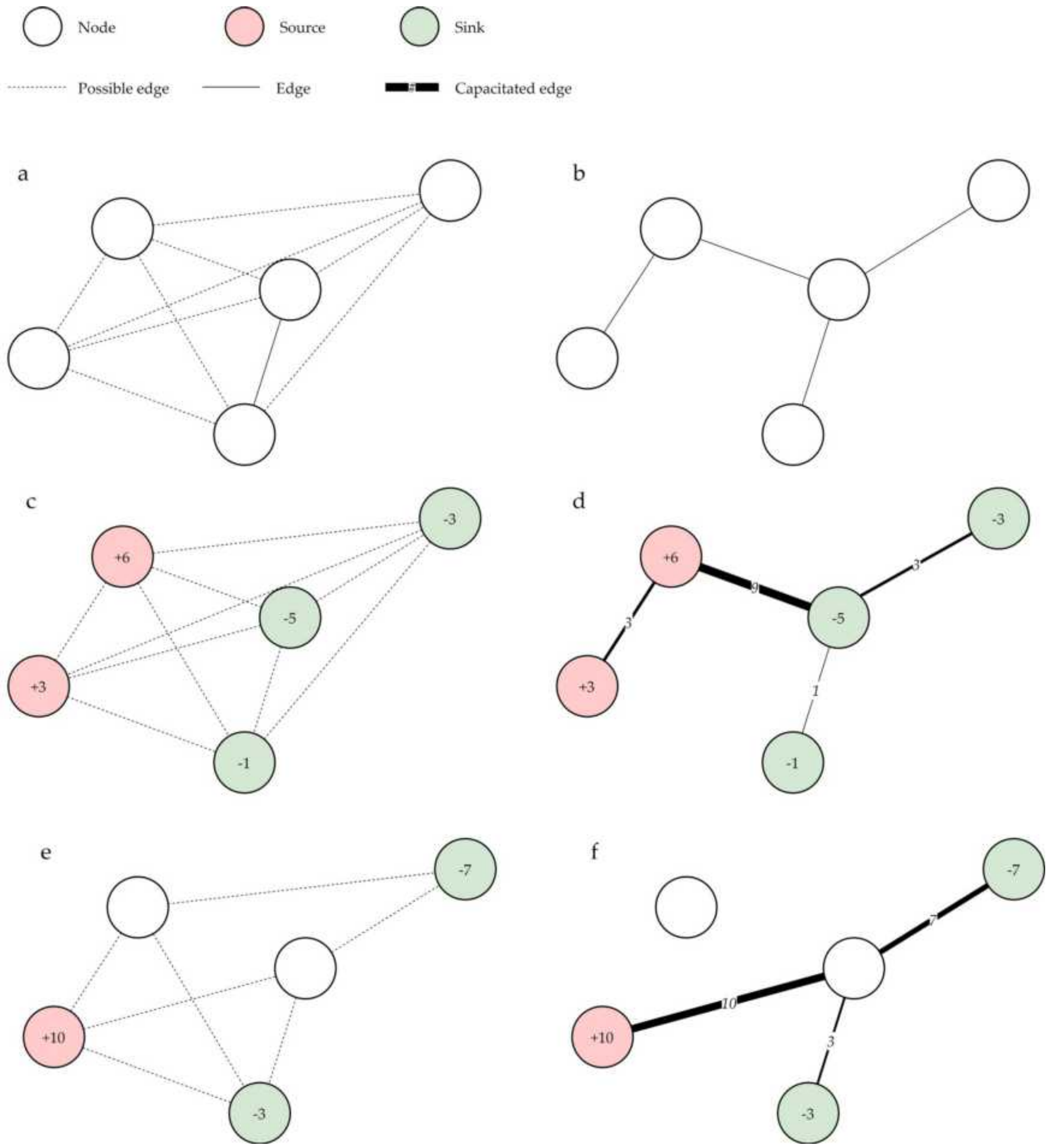

Figure 7: Fictitious example of graph theory network optimisation. In a) a set of nodes with possible edges is given, which is optimised for length in b). In c) sources with supply (red) and sinks with demand (green) are given, which is optimised for length and capacity in d). In e, sources, sinks and nodes are given with specified possible connections (routing network) which is optimised in f).

The nodes within the routing network which are connected to three or more edges and have no supply or demand (such as the white nodes in the 7e and f) are called Steiner nodes. Usually, in graph theory, Steiner nodes are implemented into networks as a new node which reduces the total network distance or cost. However, this is an NP-hard problem, meaning that the optimisation of a network which includes Steiner nodes cannot be solved in polynomial time. Therefore, many differing approximations are used, such as suggested by Heijnen et al. [129] or Yeates et al. [131]. These approaches can vary in their solution time as well as accuracy to the most optimal answer.

In the model by [129] it is possible to create Steiner points during the optimisation, in order to reduce costs. However, it is not possible and not logical to do this if a routing network is used, as the final result could deviate from the routing restrictions set. Therefore, in this study, Steiner nodes are created as part of the routing network and thus provided as an input to the optimisation. This is done by creating Steiner nodes at the intersection between different sets of LCPs [132, 127, 108].

The interaction of the cost surface, LCPs and network optimisation in this study is further explained in the methodology.

4 Methodology

The methodology contains the model formulation, data collection and preparation, scenario creation, and system cost calculation. Figure 8 below shows the work flow.

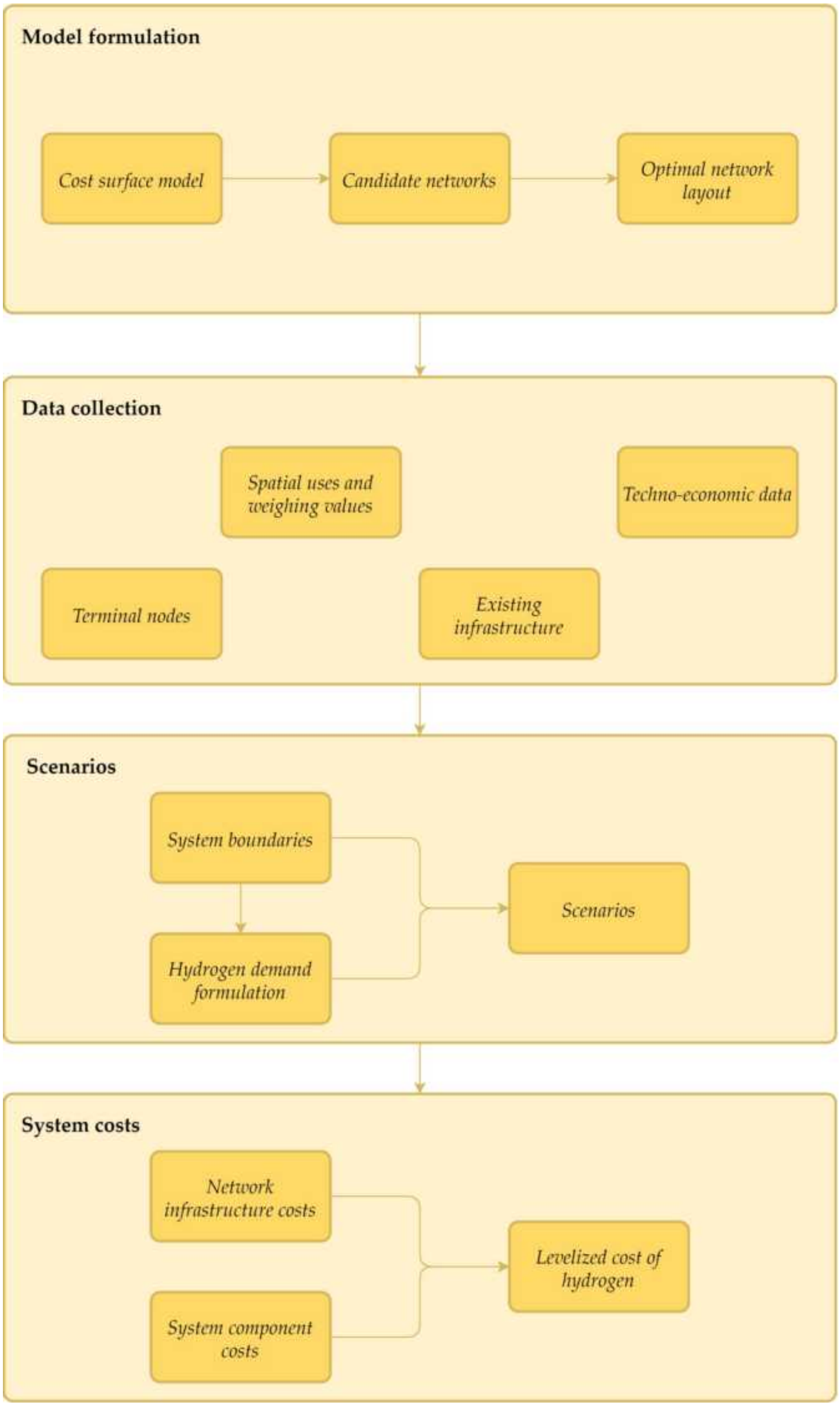

Figure 8: Methodology flowchart.

4.1 Model formulation

The model has a three-part structure as shown in Figure 9 below.

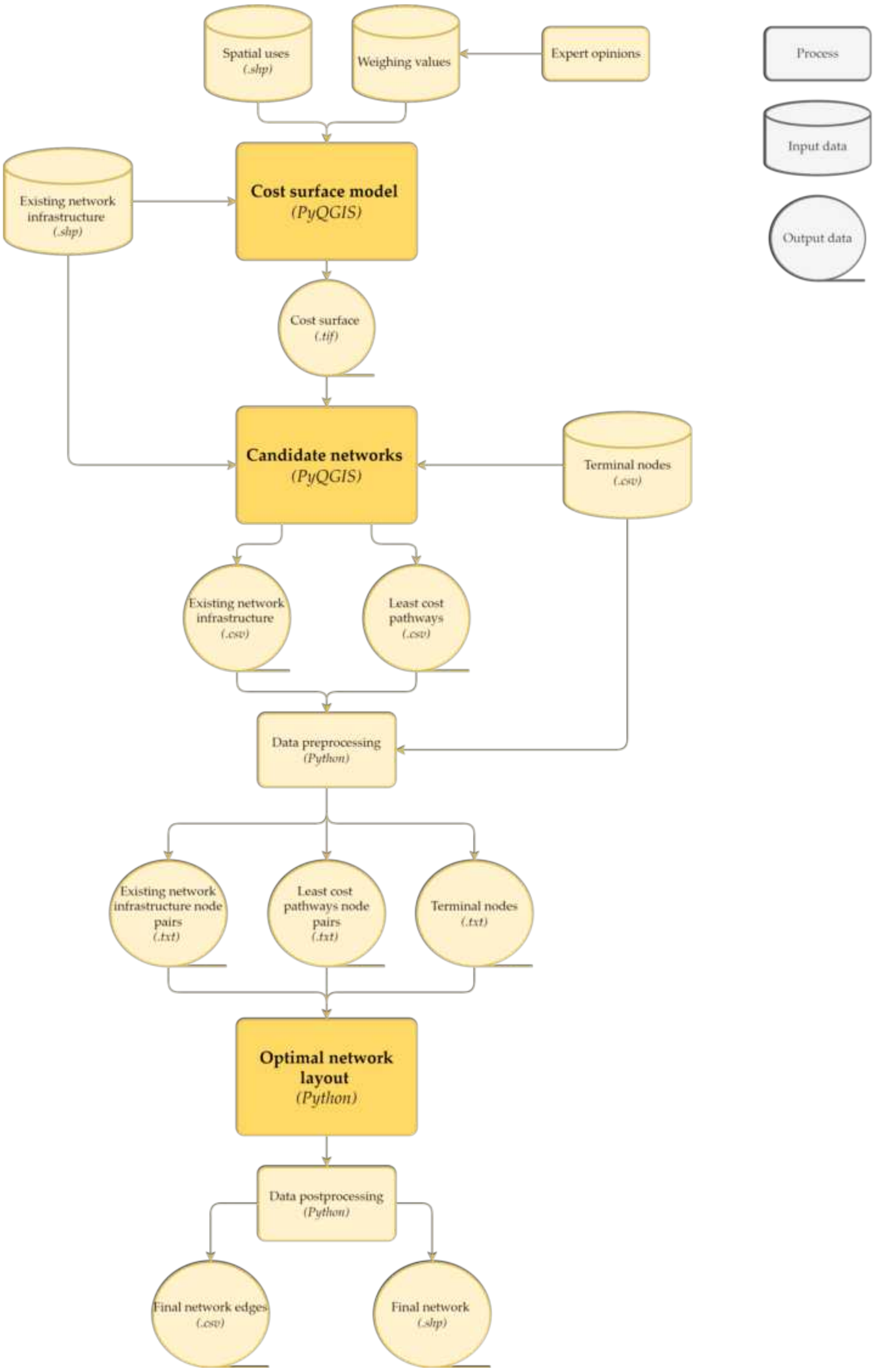

Figure 9: Model flow.

The model is set up to answer the following; how can a number of offshore hydrogen production points (sources) with a defined supply be connected with a number of onshore hydrogen demand points (sinks) with a defined demand via new hydrogen pipelines and reusing existing O&G infrastructure (edges). The capacity of the pipeline and the societal value of spatial uses in the NS is also taken into account. This is executed through three main steps as is seen in Figure 9. The first two steps, creating a cost surface and generating candidate networks are done using Python within QGIS. The last step, finding an optimal network layout is completed in Python.

4.1.1 Cost surface model

The purpose of this model is to create a cost surface over which candidate networks can be produced. The cost surface is representative of the spatial uses in study area, where a higher cost represents a higher societal cost of placing infrastructure in the area. The model is adapted from Boerhout [127] and is based within Quantum Geographical Information System (QGIS) [133]. A number of different spatial uses are collected in the format of shapefiles. Shapefiles are files which contain geographical data of certain features in vector format, commonly used in GIS software. Specifically, these are in the form of polygons and polylines, representing different spatial uses. Next, weighing values are assigned to these spatial uses. Here, weighing values can be considered as a cost multiplier for constructing (or reusing) pipelines for hydrogen transportation. However, it does not represent an accurate monetary cost, but rather a societal indicator on the costs of building hydrogen infrastructure in differing areas. Finally, the sub-model combines these spatial uses along with their relevant weighing values into a cost surface. This cost is in the form of a raster shapefile, and is used as an input to create candidate networks. An automated beta version (Python script) of the model was provided by TNO. However, the model was not complete, and thus extra functions were added:

- The ability for the model to include existing infrastructure in the cost surface. This addition follows the model structure as the one given by Boerhout [127].

- Ensuring reduced costs of using preferred infrastructure corridor routes is not double counted with the existing infrastructure. Often, preferred infrastructure corridors are in the same area as existing infrastructure. The costs should not be double counted in this case.

- Setting cost surface values where no spatial use exists as 1, to represent an accurate multiplier of the costs in a neutral area.

- Option of adding areas outside of modelling region such as the EEZ of different countries as a high value, to prevent the candidate networks to enter these regions.

Figure 10 below shows an example output of the cost surface model with 1 km cell resolution. Higher values (darker colours) are given to areas of higher societal value (such as ecological areas).

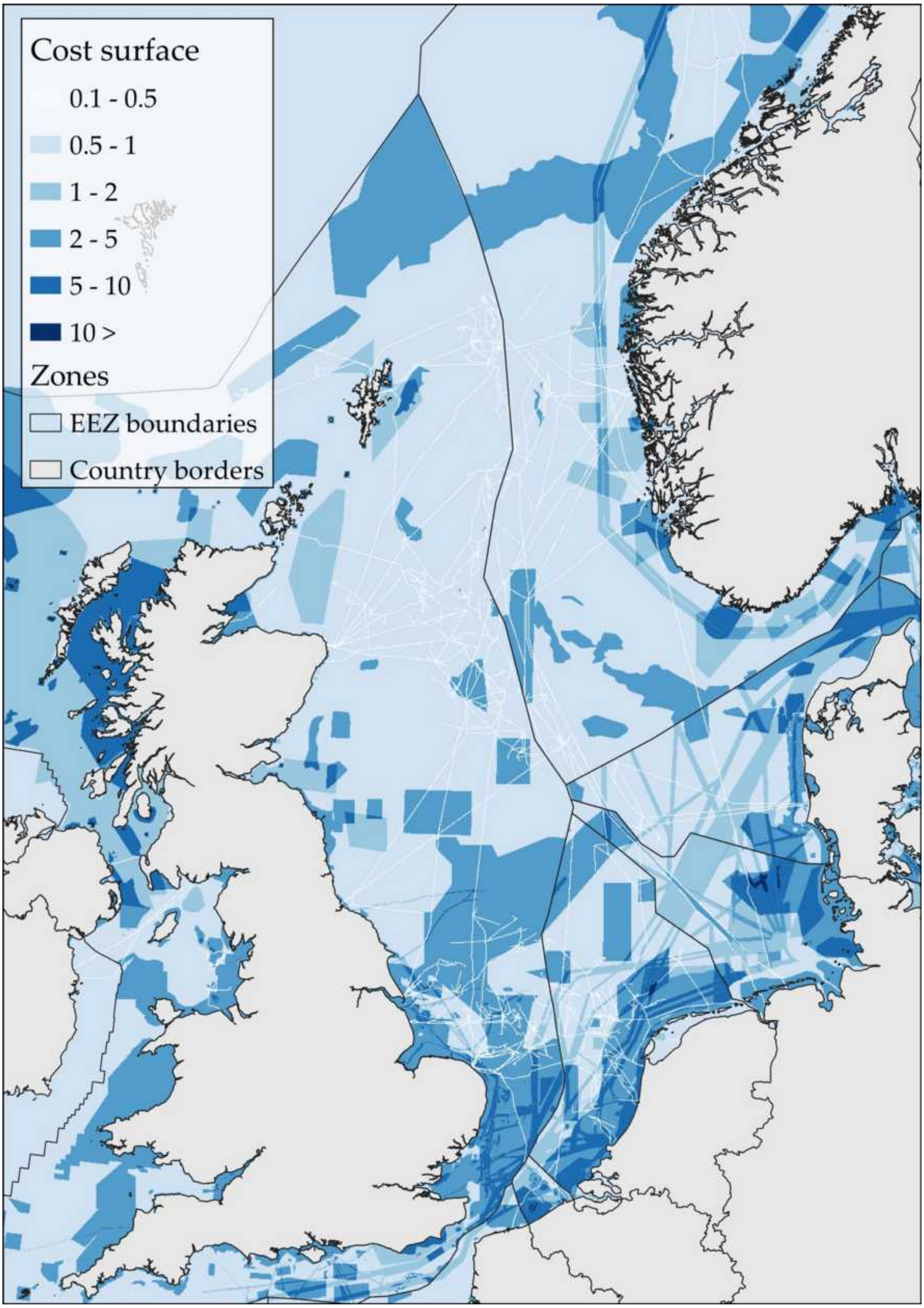

Figure 10: Example of cost surface model output of the NS region.

4.1.2 Candidate networks model

The candidate networks model uses the generated cost surface, sources and sinks to create possible low – cost connections between sources and sinks. Sources and sinks are also referred to as Terminal nodes. The model is set up as an automated sequence of QGIS tools, where the candidate networks are mostly created through least cost paths (LCPs). As explained in Section 3 LCPs are a method of determining the cheapest pathway from one node to another (or multiple nodes), based on a surface where the costs differ spatially. In this model, this is the LCPs between terminals and existing infrastructure, over the generated cost surface. This concept is implemented through the QGIS Least-Costs-Paths Network plugin [134].

The model developed in this study builds on models by Boerhout and Kwakernaak [127, 108], yet differs significantly. Firstly, potential Steiner nodes are not used as they seem to have negligible effects on the cost [127, 108]. None of the results in both studies use the potential Steiner nodes that are given as an input. Below is a breakdown of the model into sub-modules. The main techniques taken from the previous model are module 2 – first cost paths, module 3 – cleaning cost paths, and module 6 – calculating final cost paths. The other modules, 1, 4, 5 and 7 are novel.

1. **Initial set up**

Here, paths to the input data are set and output paths (to see intermediate and final results) are also created. Additionally, the existing infrastructure data is prepared for further use, by extracting vertices (inflection points in the network) as nodes. Lastly, a decision is made: *Reusing = True or False.* Default set to True. This decides whether existing infrastructure can be reused.

2. **First cost paths**

LCPs are created from source to source and from sink to source, as shown in Figure 11 below. This creates a completely connected network, which is required for the optimisation.

3. **Cleaning first cost paths**

Cost paths are then 'cleaned', where a number of procedures are undertaken.

- Cost paths with no values are deleted (where the node connects to itself)
- Duplicate geometries are deleted, where the same cost path is present between two nodes.
- Nodes are extracted from inflection points along the cost paths.
- Cost paths and nodes are assigned to the correct projection.

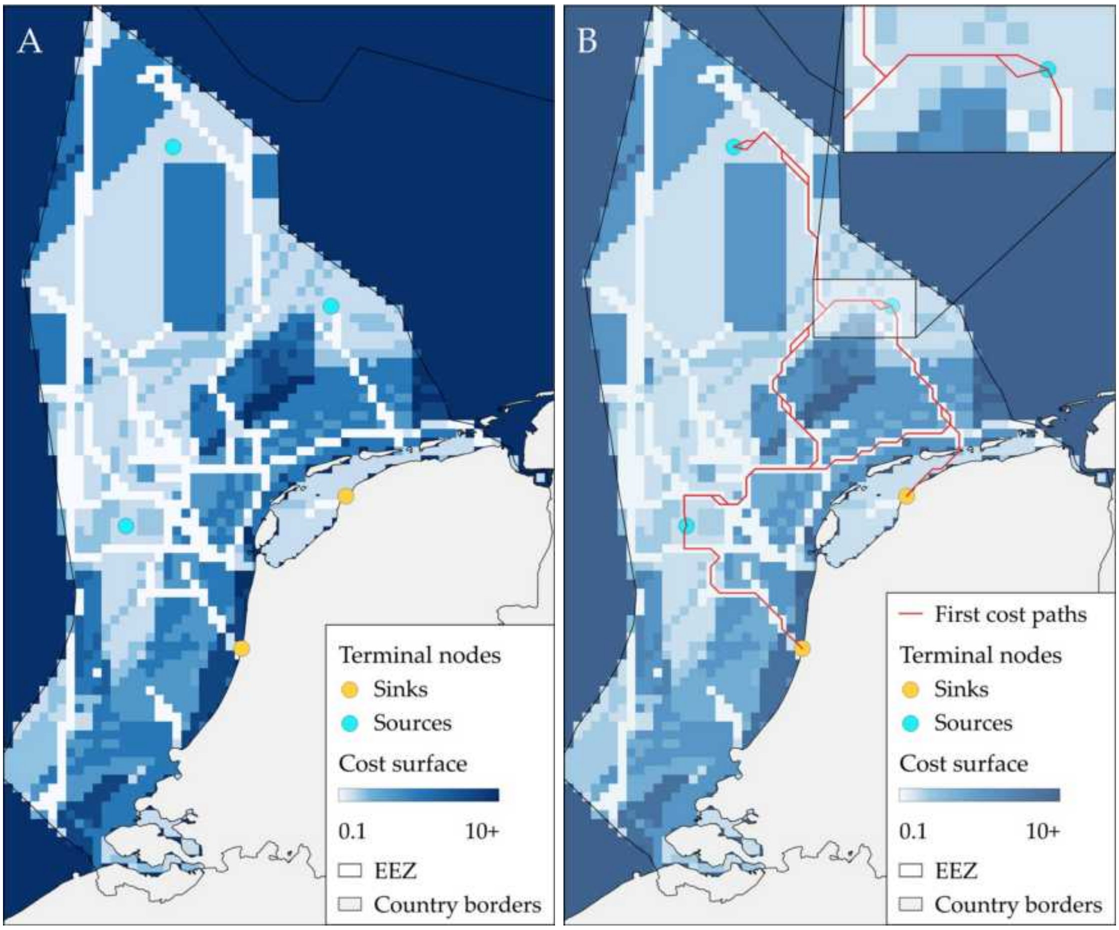

Figure 11: A set of fictitious terminal nodes and the Dutch cost surface is given in A. The first cost paths are found in B.

4. **Secondary cost paths**

If *Reusing* = *False*, this step is skipped. Figure 12 below details the steps in this module. A buffer is created around the existing infrastructure, which marks an area around the infrastructure of a certain distance, specified by the user (12A and 12B). From the First cost paths (module 2), the edges which intersect with the buffer area are removed, creating a dataset of loose candidates (12C and 12D). With these loose candidates, nodes are extracted from every inflection point, and secondary cost paths are created between the nodes of the loose candidates and the nodes of the existing infrastructure which were extracted in module 1 (12E and 12F). Additionally, cost paths are created between the sources and the nearest existing infrastructure node, as well as the sinks and the nearest existing infrastructure node (12F). These three sets of cost paths are merged and saved together as the secondary cost paths.

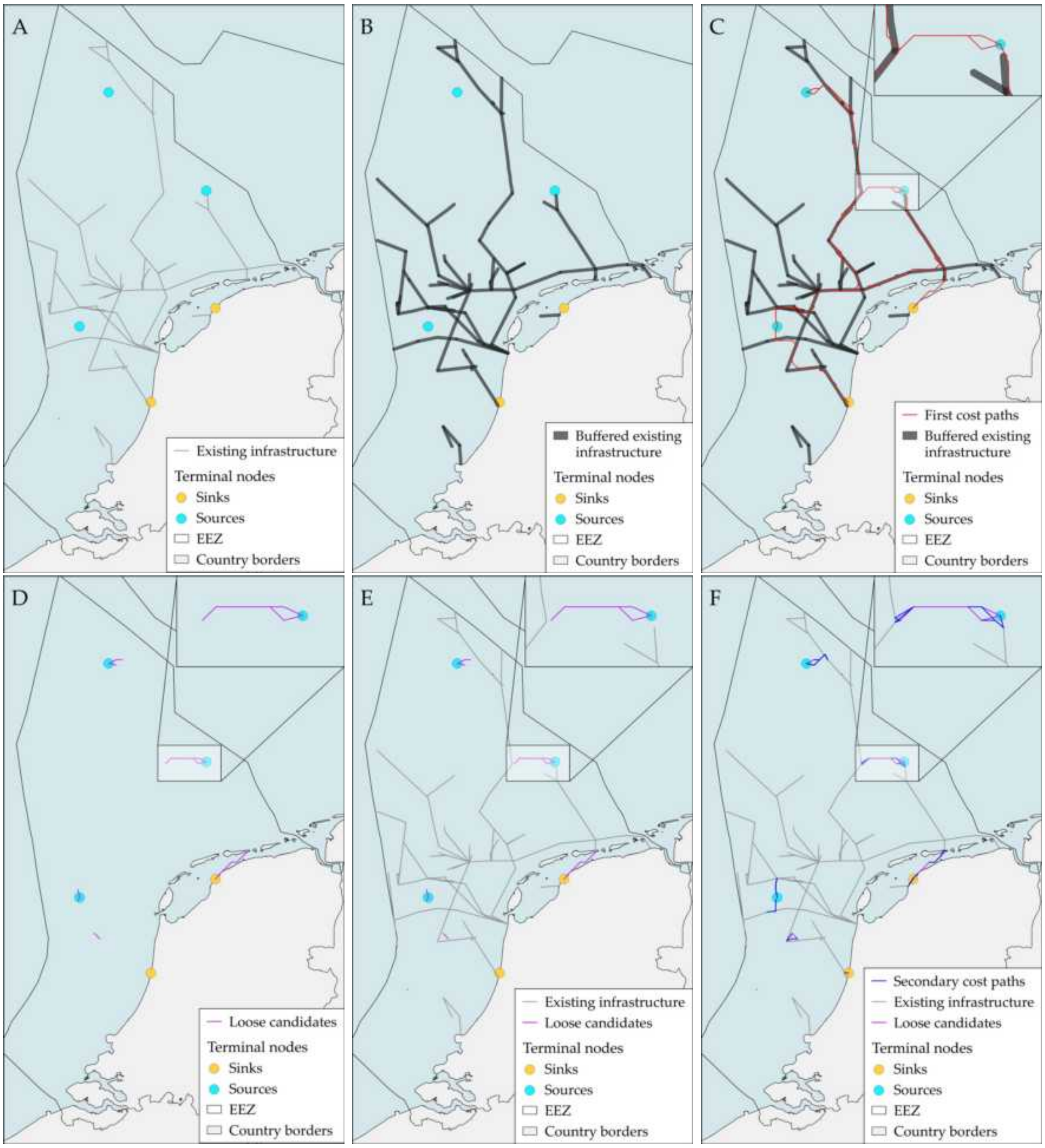

Figure 12: Creation of secondary cost paths. Existing infrastructure from A is buffered, with the result seen in B. The first cost paths which intersect the buffered existing infrastructure in C is extracted, and shown in D. The loose candidates shown in E are then connected back to existing infrastructure in F, creating secondary cost paths.

5. **Cleaning secondary cost paths**

If *Reusing* = *False*, this step is skipped. Similarly to step 3, cost paths are cleaned by deleting duplicate geometries, extracting nodes and projecting layers to the correct coordinate reference system. Two additional steps are taken. The cleaned secondary cost paths are merged with the first cost paths (see Figure 13), and the cleaned secondary nodes are merged with the first cost paths nodes. Duplicate geometries are deleted, and individual edges are created where inflection points exist.

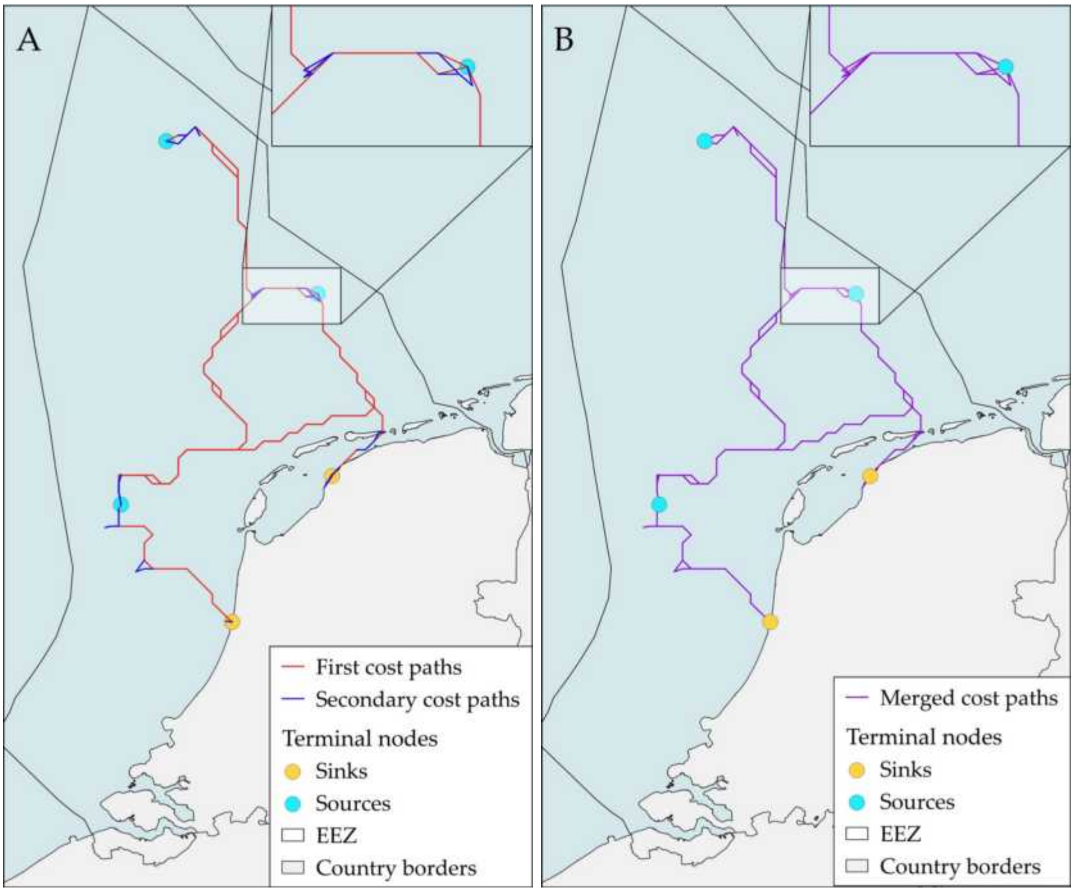

Figure 13: The first cost paths and secondary cost paths shown in A are merged in B.

6. **Final cost paths**

If *Reusing* = *True*, use outputs of module 5. If *Reusing* = *False*, use outputs of module 3. This step ensures that the costs between two nodes are correct. Here, for every individual edge (between two nodes), both nodes are extracted. For these two nodes, a final LCP is ran, which calculates the correct cost. Figure 14 below visualises this process.

7. **Exporting data**

Final cost paths are cleaned by fixing invalid geometry. An unique id is added to each individual edge. Nodes are then extracted, which creates two nodes for each edge. These nodes are named node pairs, and are an input to the following model (see Figure 15). If *Reusing* = *True*, the nodes of the existing edges are also extracted. This results in two output datasets in csv files, which are inputs for the optimisation. The candidate node pairs store the cost (from Figure 14B) and the existing infrastructure node pairs store the capacity/diameter of the edge of which they are the start and end points.

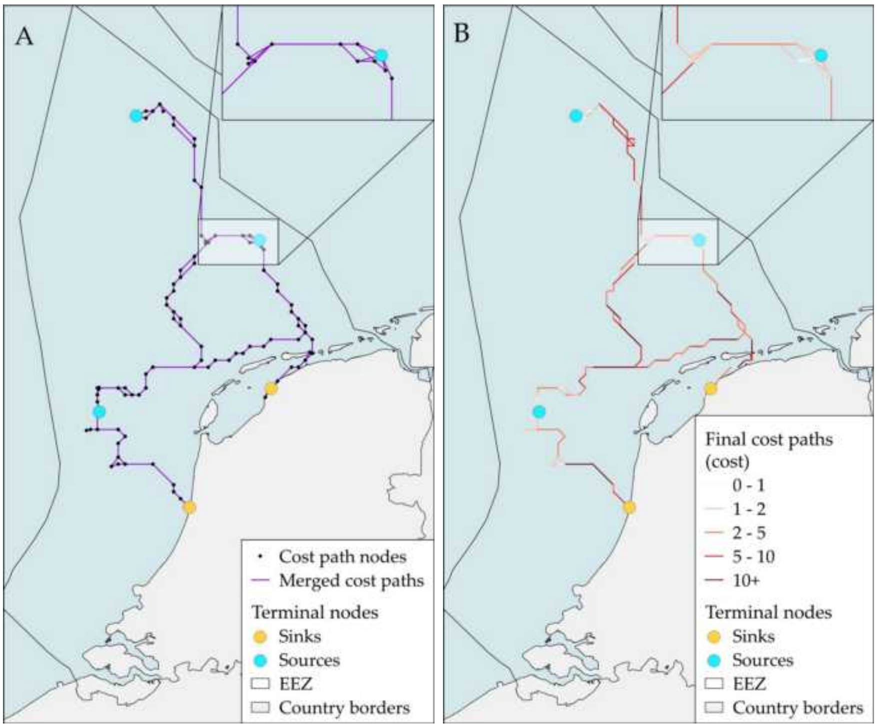

Figure 14: Calculating final cost path values between individual edges. In A, nodes are extracted from the start and end of each edge. In B, the final cost is calculated.

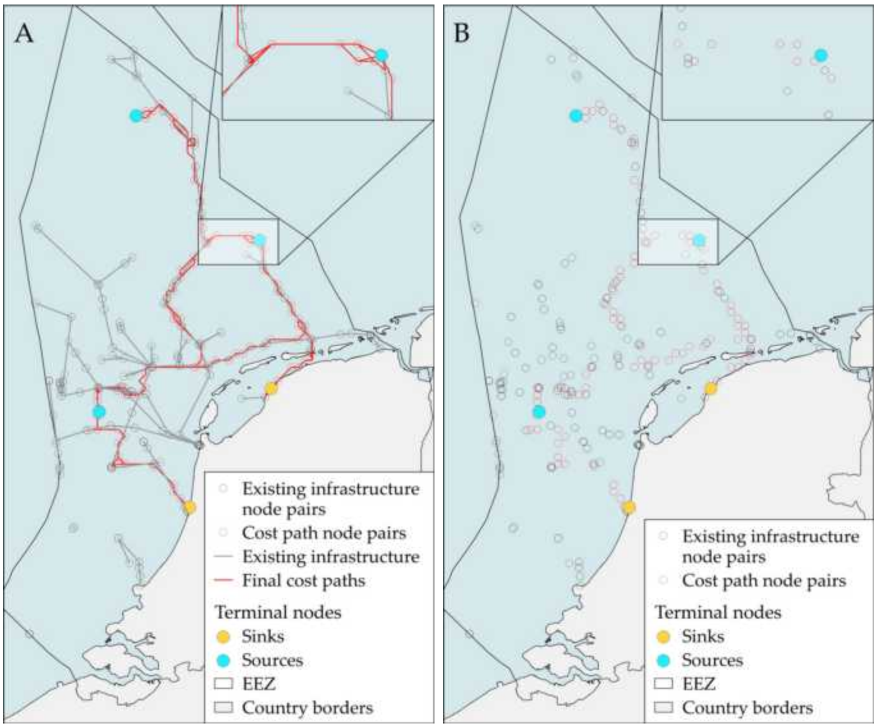

Figure 15: From A to B, extracting the node pairs from the existing infrastructure and final cost paths, on every inflection point in each data set.

4.1.3 Optimal network layout

The ONL model developed by Heijnen et al. [129] connects multiple sources and multiple sinks with capacitated edges, ensuring supply meets demand in all nodes. Importantly, the supply and demand must be set manually by the user, and must equal each other. The optimisation procedure of the ONL is limited in this study by the candidate networks and the existing infrastructure network, along with the existing capacities of the latter. For the purposes of the research, the model is adapted. The objective function (Equation 1 below) is adapted in comparison to the original model and is inspired by Geutjes and Heijnen et al. [135, 129].

Objective function:

$$Minimize\, C(G) = \sum_{e \in E_n(G)} w_e q_e^{\beta} + cpc \sum_{e \in E_o(G)} w_e (q_e - q_{e,r})^{\beta} + rpc \sum_{e \in E_o(G)} w_e q_{e,r}^{\beta} \tag{1}$$

Where the objective is to minimize the total cost C of network G, which is made up of a set of new edges E_n and existing edges E_o. The individual edges e have a specific weight w, capacity q and a capacity-cost exponent β, where $0 \leq \beta \leq 1$. Existing edges have a remaining capacity $q_{e,r}$ which has a repurposing cost multiplier *rpc* and a capacity extension cost multiplier *cpc*. The main changes in comparison to the original are listed below. For specific changes to the model code, see Appendix A.

- The added function of a repurposing cost, as defined by Geutjes [135].
- The use of an edge weight w instead of the length of the pipeline. This weight is calculated through multiplying the lengths of the edges with the costs of the underlying cost surface, which are defined from the weighing values in Table 3.

The model structure is set up in the following steps. For visualisations of the model steps and a full breakdown of the equations used, see [129, 66].

1. **Read input data**

Here, the input data is prepared for the model. This includes preparing files, assigning values to input parameters and creating the scope of the optimisation. To prepare the node pairs of candidate networks and existing infrastructure, the datasets are grouped by unique identifiers. For the candidate network it is the edge id, and for the existing infrastructure it is the name, angle and diamater of the edge. The diameters of the existing infrastructure must be converted to a capacity, which is done following similar data from Hy3 report [136] (see Appendix B, where the high-heating value (HHV) of hydrogen and 20 m/s flow speed is assumed within pipelines). This results in a similar diameter to capacity conversion as seen in the EHB [40]. Terminal nodes are also prepared, as well as their supply and demands which is further discussed in the System Boundaries subsection below. All files are prepared as text files, which is the necessary format for the ONL model. The input parameters are set in table 1 below.

Table 1: Input parameters for ONL model.

Variable	Value	Justification
β	0.6 and 1	0.6 widely used as a standard capacity cost exponent for hydrogen pipelines [89, 129, 131]. For electricity cables, a value of 1 used as it is assumed there are no cost – benefits of increasing capacity (see appendix B).
cpc	0.78	Factor for reusing existing corridors defined by Thoonsen [128]. It is assumed that capacity extension cost = reusing existing corridor.
rpc	0.1	This value lies somewhere between 0.1 and 0.4 [55, 56, 41]. However, the lower amount is chosen.

The scope of the optimisation is also decided here through decisions, namely:

- *Routing = True or False.* Whether there are routing restrictions for the network. Default is True. This limits the scope of the optimisation, as the solution is confined to the possible configurations of the candidate network.
- *Obstacles = True or False.* Whether there are obstacles in the search are of the network. Default is set to False.
- *Existing = True or False.* Whether there are existing connections to be reused. Default is True. The capacities of the existing connections sets a limit to the model of how much can be reused for hydrogen.
- *Route costs = True or False.* Whether the societal costs of the routing network should be taken into account. Default is True.

In the original model there are is also the opportunity to add a cost to splitting points, which represents a fork-like connection. However, this is not taken into account, as the costs were estimated to be negligible for hydrogen pipelines in discussions with industry experts at TNO and NSE. For electricity cables they were not used as specifying where to set converters on splitting points was left out of scope.

2. **Analyse demand-supply patterns**

If data is available for multiple time-steps, this step is used to analyse all the supply-demand patterns at the nodes. In this model however, only one time-step is used. These values are set manually by the user and the total supply must equal the total demand. This is further elaborated in the scenario section.

3. **Determine representative set of k demand-supply profiles**

If many time-steps are given, this step is able to choose a representative set of supply-demand profiles. This is useful to break down a large dataset into a manageable one, while attempting to keep resolution on the energy needs of all supply and demand profiles. The model can then calculate the maximum capacities needed for the pipelines to satisfy supply and demand. There is only a singular time-step and thus only this time step is used.

4. **Minimal spanning tree (MST)**

In this step, the initial MST is found, and capacities are assigned to the edges to satisfy the supply and demand. In the original model, this would use the distance of edges to create the MST. However, in this model, the weight of the edge is used instead, which has been defined by the pre-optimisation steps. To implement this change, the model code is changed at several points.

5. **Minimum cost spanning tree (MCST)**

The cost of expanding capacity is not considered in the minimal spanning tree. The capacity cost exponent reflects the real-world phenomena that the cost per km of transported (hydrogen) gas decreases with an increase in the capacity. In this step, the network is "rewired" using the edge-swap heuristic [129]. Here, edges with high costs are swapped iteratively and assigned capacities in order to find cheaper network configurations. When no cheaper configurations are found, the optimisation ends. It is important to note that this is not a guarantee to find the cheapest network, as it is a heuristic.

Note: due to this optimisation methodology, as well as the large amount of offshore wind farms, the results exhibit connections on the scale of 10s of GW. This is a representation of multiple pipelines or cables which are clustered next to each other, rather than a single infrastructure connection. In fact, the current largest capacity HVDC cables are around 2 GW, whereas the largest pipeline capacity is 48 inches (around 13 GW) [137, 82].

4.2 Data collection

4.2.1 Spatial uses

A number of spatial uses were collected by the author as an internship project prior to this project and are shown in Figure 16 below.

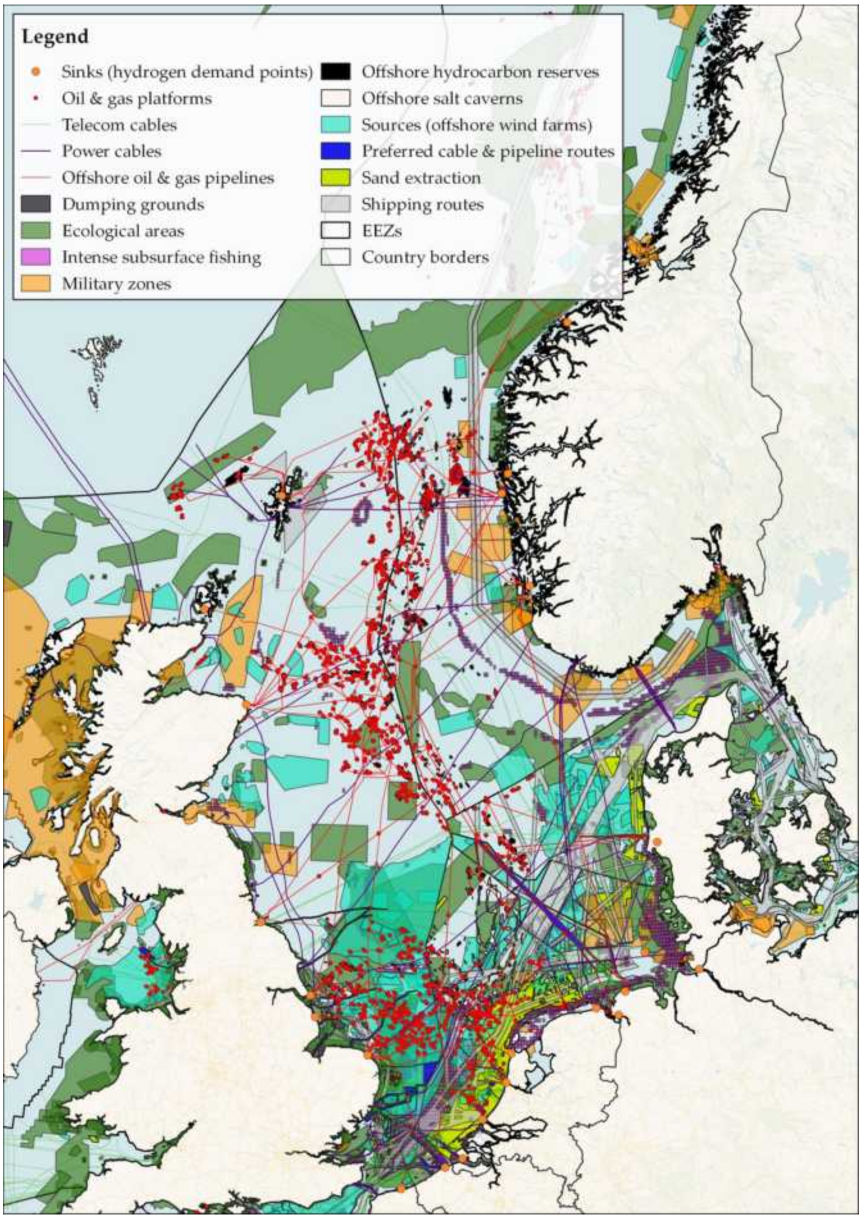

Figure 16: Spatial uses and infrastructure in the NS. Data collected as part of internship project.

Table 2 below shows the relevant data that was kept, the main sources and the edits made. For an exhaustive list of the sources please see Appendix B. Not all spatial uses are available in all countries, such as dumping grounds for DK. This may be due to the country not utilising the practice, or that the data is too sensitive to be shared. Additionally, not all spatial uses can be

Table 2: Spatial uses and existing infrastructure data used for the modelling. See Appendix B for sources.

Spatial use	Countries	Comments	Source(s)
Military areas	All (exc. DE)	Areas designated for military exercises	EMODnet, Overpass Turbo, MSPs, NMPI, Geonorge.
Sand extraction	All (exc. NO)	Areas where sand or aggregates are extracted from the sea bed.	EMODnet, MMO, MSPs, Overpass Turbo.
Preferred (cable and / or pipeline) routes	All (exc. NO)	Many countries have defined preferred cable and / or pipeline routes in their MSPs.	Rijkswaterstaat, EMODnet, MSPs.
Ecology	All	Includes protected areas for all countries.	EMODnet, OSPAR, MSPs, Miljodirektoratet.
Shipping routes	All	Data collated from multiple sources.	EMODnet, MMO, MSPs, Overpass Turbo.
OWF	All	Final capacities and locations of offshore OWF based on 4C Offshore database. Dataset last updated in May 2022.	4C Offshore, EMODnet, Rijkswaterstaat, Scottish Government, MSPs, Netzentwicklungsplan, Energistyrelsen, NVE.
Offshore O&G pipelines	All	Pipeline ends are joined. Segments are simplified, duplicates are deleted. Pipelines below 14 inch are removed.	EMODnet, OGA.
Offshore electricity cables	All	Based on existing cables as well as planned and possible development areas.	4C Offshore, EMODnet.

modelled appropriately. An example of this is cultural heritage sites such as wrecks. These are on the order of several hundred meters, whereas the model operates on a macro scale of several km. Additionally, the cost of rerouting infrastructure by several hundred meters is negligible in comparison to the total cost of a NS-wide infrastructure network. To standardise the spatial uses across the NS, the most prevalent and important spatial uses were used. In previous studies by Thonseen [128] and (later adapted by) Boerhout [127], weighing values (previously named as 'Use Factors') were given to these spatial uses (previously named as 'Use Functions') through consultation with industry stakeholders from NL. As the scope of the project is increased to the NS, it is important that the weighing value also reflect the opinions of experts in these countries. Efforts were made to conduct a series of interviews with marine authorities of the separate countries to find appropriate weighing values. However, difficulties arose as the assigning weighing values to spatial uses was deemed too complex in a short time period without the cooperation of many ministries. Therefore, the weighing values of NL were extrapolated to the other countries. The interview notes are provided in B. The final weighing values and spatial uses are seen in Table 3.

Table 3: Spatial uses and their weighing values. Weighing values defined by Thoonsen [128] and Boerhout [127]. Note that corridor reuse and preferred routes have the same value. The difference in both is that the preferred routes are defined by MSPs, whereas corridors are defined by existing infrastructure.

Spatial use	Weighing value
Ecology	5.1
Sand extraction	3.42
Military	1.53
Shipping lanes	1.66
Preferred cable & pipeline routes	0.78
Pipelines reuse	0.1
Infrastructure corridor reuse	0.78

4.2.2 Terminal nodes

Locations of the terminal nodes (sources and sinks) are defined. Sweden and France are left out of scope, as their share of the NS is small and planned OWF are very close to shore.

Sources are based on the locations of OWF, where it is assumed offshore electrolysis using sea water and electricity from OWF can take place. Collection of the OWF dataset was also completed during the previous internship project. To accurately represent the possible scope of hydrogen pipeline networks in the NS, the number of sources is limited. This is done in a number of ways.

- OWF which are out of scope of the NS are removed. These can be seen on the map below (Sweden, France, Baltic Sea, west of Scotland, northern seas of NO).
- The OWF dataset was updated (in May 2022), using 4C Offshore. The OWF datasets are updated daily by 4C Offshore. OWF which are in contact with each other and have the same name are merged together as one, and their capacities are summed.
- Generic bidding zones and cancelled, decommissioned and dormant projects are excluded.
- Areas reserved for possible energy islands are excluded.

- Existing, active OWF (which are already connected to the electricity grid) are excluded.
- OWF which are planned to be fully operational before 2030 are excluded, as they will likely be connected via electricity cables.
- Where possible, planned electricity cable connections to OWF are taken into account, and the connected OWF are excluded. An assessment of each country is completed below.
  - **Belgium- (BE) -** Interestingly, BE are planning to connect to the UK via an interconnector and the Princess Elisabeth offshore wind zone [138]. However, it is confirmed by the Belgian government that the TSO (Elia) is responsible for constructing an offshore grid, with no mention of hydrogen production [139]). Additionally, the future offshore OWF in BE will be active before 2030.
  - **Netherlands (NL) -** Possible energy islands have been defined in the Dutch NS such as by [140], but no solid plans have been made so far. On the other hand TenneT have identified OWF areas to which they will connect to before 2030 [141].
  - **Germany (DE)** – In DE plans have been made to connect to all OWF via cables in zone 1 to 3 in the MSP by the Netzentwicklungsplan [142]. However, no plans have been made yet to connect zone 4 and 5, which are further out in the sea. Interestingly, additional possible OWF areas are identified in zone 4 and 5 than is stated in the MSP. However, they are not confirmed. Additionally, the TSOs have stated they would rather onshore electrolysis, as it provides more flexibility in the end use of the electricity generation. Moreover, they have stated that they are encouraging a NSWPH, with plans of 2 GW of interconnection between neighbouring countries.
  - **Denmark (DK)** – There are plans for an offshore energy island in the NS by 2030, which will accommodate the 3 GW of OWF. However this will initially be connected with electricity [143]. How the additional 10 GW increase thereafter is connected has not been planned yet.
  - **Norway (NO)** – The government have recently planned 30 GW of offshore wind by 2040, where they envision a large part of this will be available to go to other countries [144]. Sites will be chosen following research by NVE in 2022-23 [145], and licensing is set to start in 2025. For the already designated areas, it is stated that Phase 1 (1.5 GW) of the future wind farm Sørlige Nordsjø will be connected via electricity and only to the Norwegian mainland, with no connection possible to other countries. However, Phase 2 (1.5 GW) may have a different connection. Statnett (the TSO of NO) will complete a study on this during autumn 2022 [145].
  - **United Kingdom (UK)** – The UK have extensive plans for offshore wind which is led through the Offshore Transmission Network Review (OTNR). By June 2022,

a coordination project will be completed which will attempt to coordinate offshore wind farm projects together, named the Holistic Network Design Methodology [146]. Additionally, the UK government are eager to develop multi-purpose interconnectors in the near future, as well as aiming for 50 GW of offshore wind by 2030 [147]. Some future offshore bidding zones are identified by 4C Offshore, however, these are very large generic zones, lacking details on the placement and capacities of OWF. The OTNR provide a map on the planned OWF, where it is seen that many are expected to be connected via electricity cables [148].

The final dataset has 44 OWF, totalling 103.1 GW. The final locations are seen in Figure 17. To convert these areas into source nodes (for the model), the center of each OWF is found using QGIS.

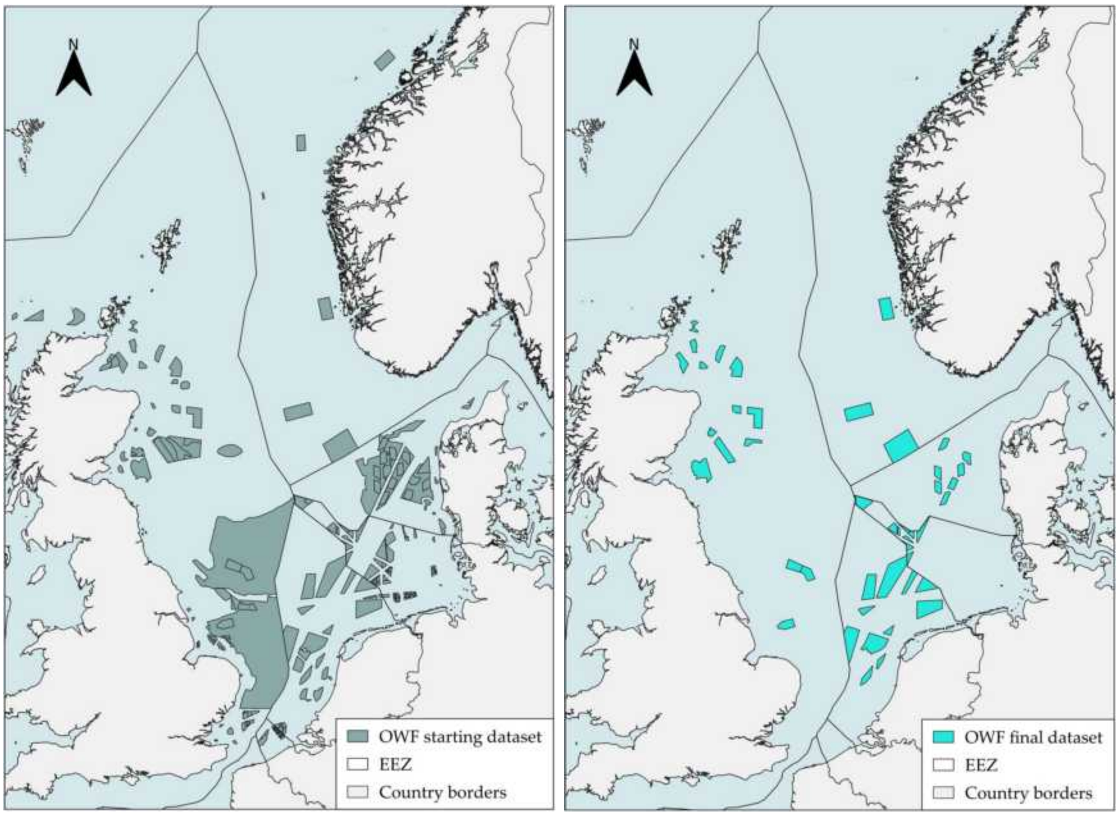

Figure 17: Comparison of starting dataset (left) of offshore OWF to final dataset (right).

Sinks are located based on existing O&G infrastructure docking points (Figure 18), which are normally located by large industrial clusters. These areas are chosen as they already have facilities for treating gas, and are likely to significant hydrogen demand in the future due to their proximity to industrial clusters. Additionally, some sinks are chosen based on planned future hydrogen projects. Specifically, Helgoland and Brunesbuttel are part of the AquaVentus project [149], and Zeeland is part of the HyWay27 project [62].

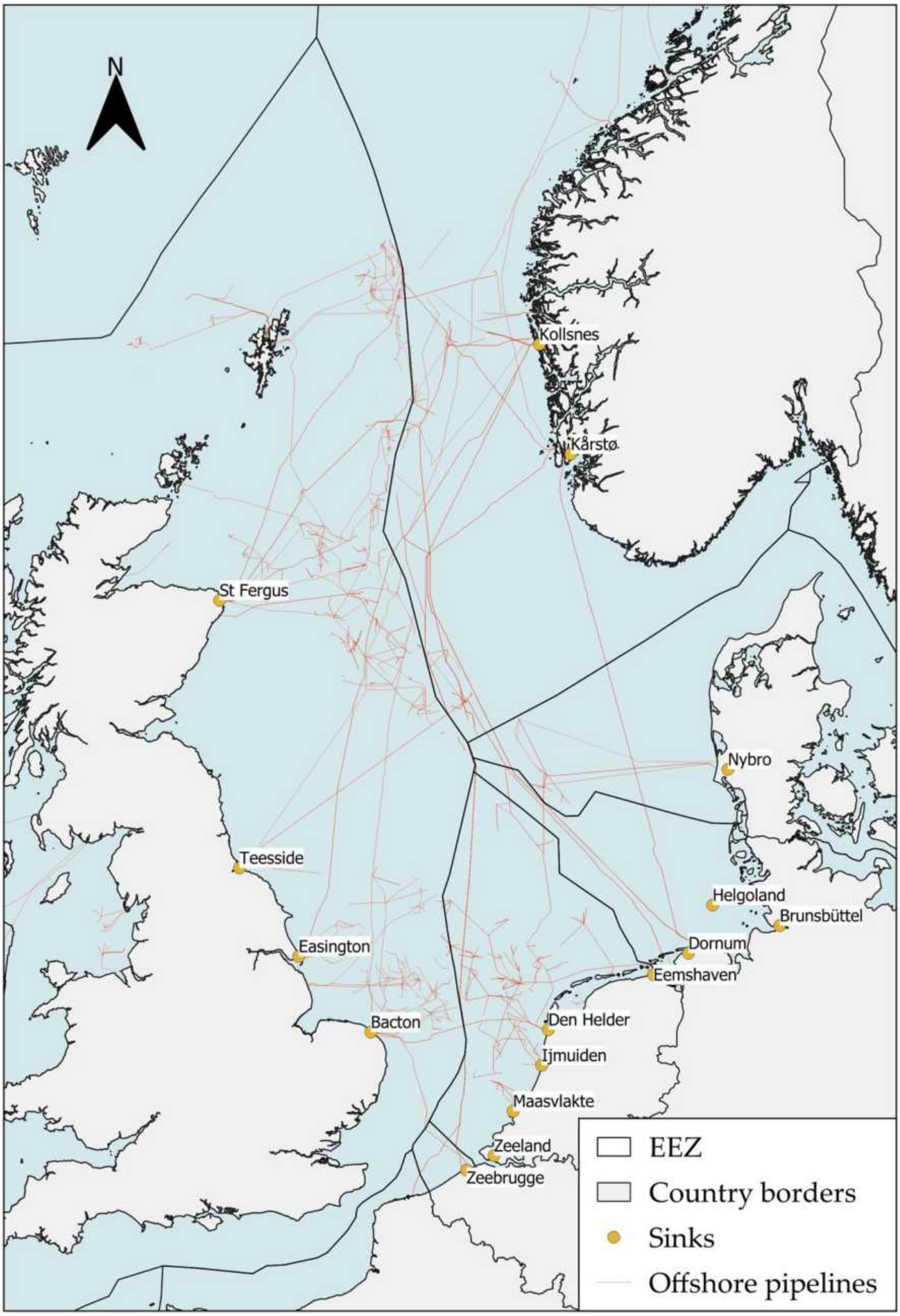

Figure 18: Sinks, with associated O&G pipeline infrastructure and industrial clusters.

4.2.3 Techno-economic data

Costs of infrastructure are derived from the Danish Energy Agency, internal TNO data and other sources. The system components are shown in Table 4 (technological parameters) and Table 5 (economic paramaters). Cost and efficiency values of 2040 are used as it is imagined the planning of these infrastructures will not be completed before then. For the electricity components, HVDC cables are used because they are generally preferred over HVAC for long distance and offshore use as they have lower losses [150]. Techno-economic parameters left out of scope are re-compression (booster) stations and additional converters (e.g. at splitting points), as the network optimisation formulation does not consider these. Hydrogen distribution and end-use adaption are also not considered due to being outside of the system boundaries (see Figure 19).

Table 4: Technology data used in study.

Parameter	Value	Unit	Source(s)	Notes
Lifetime	30	Years	[151, 21], own analysis.	Average of lifetimes used. Used for all technologies.
Capacity	103.1	GW	[152], own analysis.	See terminal nodes section for analysis.
Full load hours	4900	hr/yr	[151]	2040 estimate.
Electrolyser capacity	% of OWF capacity	GW		Offshore and onshore capacity varies per scenario.
Electrolyser load factor	97%	%	[151]	
Electrolyser efficiency	70%	%	[151]	Average of PEM and AEK in 2040.
Water requirement (for electrolyser)	188.5	t/GWh electricity input	[151]	Average of PEM and AEK in 2040.
Desalination unit power requirement	2.99	kWh/t water	[21] [21]	
Compressor energy demand	0.8%	% energy loss	[151]	Compressing from 35 to 70 bar. Average of 2030/50.
Pipeline energy losses	0.0031%	%/km	[151]	70 bar, 1000 km pipeline. Average of 2030/50, above 0.25 GW capacity.
HVDC cable losses	0.0035%	%/km	[150, 25]	Per 1000 km cable.
Converter station losses	1%	%/station	[150, 25]	
Number of converter stations	2	Stations per cable connection.	[25]	

Table 5: Economic data used in study.

Parameter	Value	Unit	Source(s)	Notes
Discount rate	4%	%	[151]	
FOM (standard)	2%	%	[21]	Used for technologies where actual FOM was not found
OWF	1.44	M€/ MW	[151]	Equipment and installation of array cable, turbines, foundations and project development. 2040 estimate.
OWF FOM	0.033	M€/ MW / yr	[151]	2040 estimate.
OWF VOM	3.3	€/ MWh	[151]	2040 estimate.
Offshore platform	0.9	M€/ MW	Internal NSE / TNO data	
Platform FOM	Standard FOM			
Desalination unit CAPEX	3500	€/ kW	[27, 21]	
Electrolyser CAPEX	0.375	M€/ MW	[151]	Average of PEM and AEK in 2040.
Offshore electrolyser CAPEX	116.3%	M€/MW	[27]	Compared to onshore electrolyser
Electrolyser FOM	0.01	M€/ MW / yr	[151]	Average of PEM and AEK in 2040.
Compressor CAPEX	3.4	M€/ MW	[59]	
Offshore compressor CAPEX	200%	M€/MW	[27]	Compared to onshore compressor
Compressor FOM	8%	% of CAPEX	[21]	
Pipeline CAPEX	Variable	M€/ GW / km	Internal NSE TNO data based on real projects [21].	Values are interpolated between different capacities and distances.
Pipeline reuse cost	10%	M€/ GW / km	[59]	Reuse cost of pipelines, compared to new hydrogen pipeline CAPEX
HVDC cables	Variable	M€/ GW / km	Internal NSE TNO data based on real projects [21].	Values are interpolated between different capacities and distances.
HVDC cable components (Converter, offshore platform, onshore station)	Variable	M€/ GW	Internal NSE TNO data based on real projects [21].	Values are interpolated between different capacities and distances.

4.3 Scenarios

4.3.1 System boundaries

To compare transportation networks, the system boundaries are set below in Figure 19.

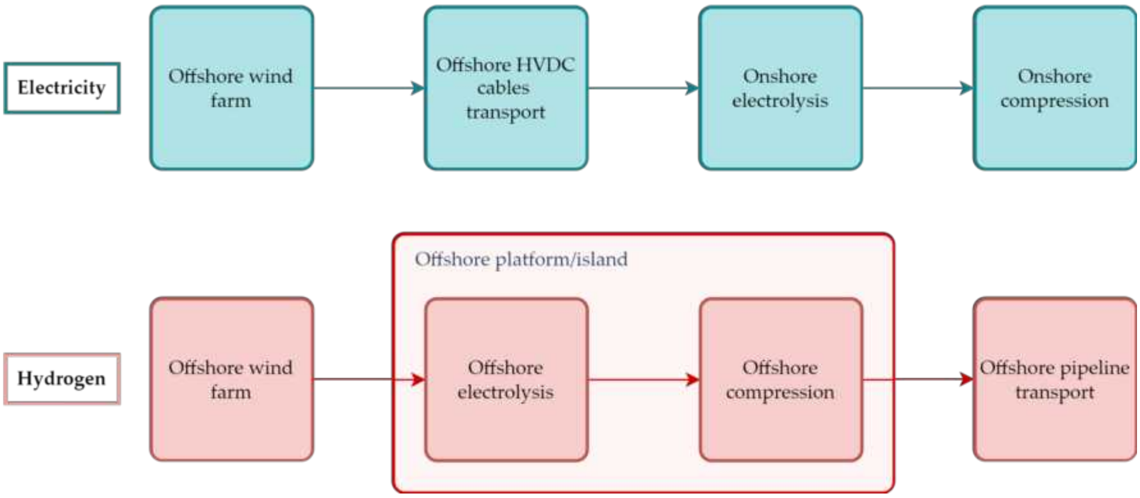

Figure 19: System boundaries of electricity grid (above) and hydrogen network (below).

Additionally, the hydrogen supply and demand must be defined in the sources and the sinks. Hydrogen supply in the sources is limited by the available capacity and average load factor OWF, the (expected) efficiency of electrolysers, and the limits set in the different scenarios. The total onshore hydrogen demand will likely exceed the offshore hydrogen supply. This is roughly estimated by using the techno-economic data from 4.2.3, resulting in a technical possibility of around 360 TWh/yr of offshore hydrogen generation. This is less than the estimations of onshore demand by Groß et al. [153] in Figure 20, where demand NS-region countries is considerably higher. Similarly, a higher onshore demand than offshore production is seen in [30]. In the model used in this study, total demand in the sinks must equal the total supply in the sources. Therefore, the supply-demand amount is defined through the total supply. As established previously, total supply (and thus demand) equates to 103.1 GW. Importantly, the demand varies spatially in each sink. For projections of hydrogen demand in 2050, data is used from the Horizon 2020 HyUSPRe project [153] in Figure 20. In the study, hydrogen demand is estimated in 2050 for transport, industry feedstock and process heat. All demands are considered in this study, setting it apart from other hydrogen network optimisation studies.

As Figure 20 shows, the demand is given on NUTS-2 level. The sinks (see Figure 18) adopt the demand of the NUTS-2 areas in which they are located, through a spatial join. In the case where multiple sinks are within one NUTS-2 level, the demand is shared equally between each sink. The relative differences in demand are found, and matched to the offshore supply. This is shown in Table 6. A comparison of the spatial aspect of hydrogen demand is made in Appendix B.

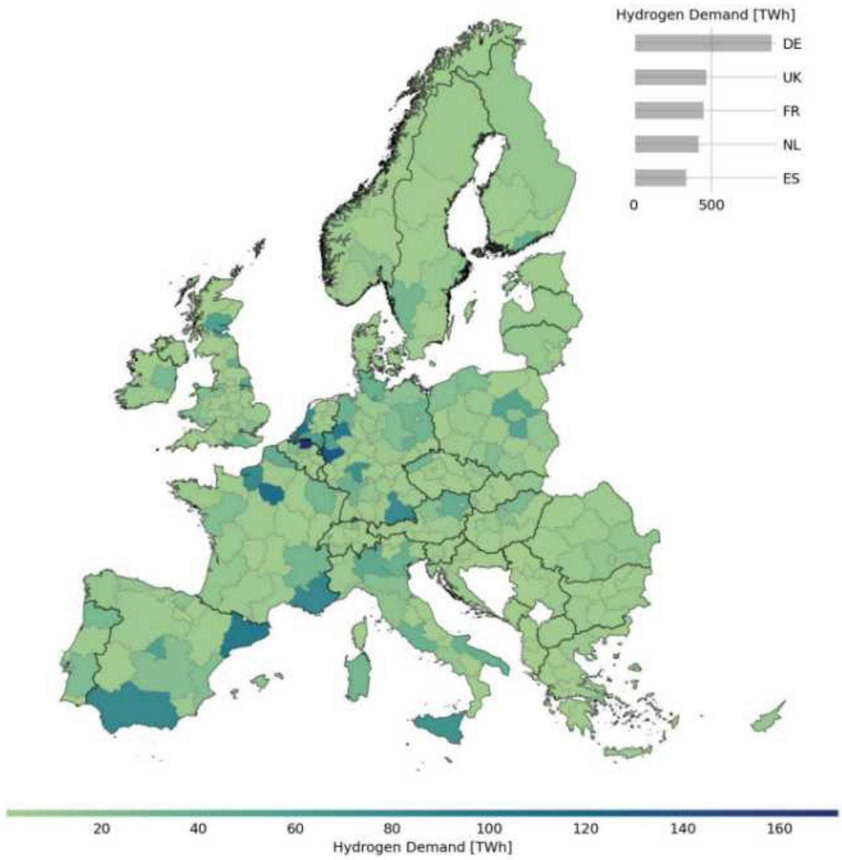

Figure 20: Total hydrogen demand in Europe on NUTS-2 level in 2050. Data from HyUSPRe project [153].

Table 6: Normalised hydrogen demand for all sinks. See Figure 18 for sink locations.

Sink name	Country	Percentage of total demand	Normalised demand (GW)
Zeebrugge	BE	2%	1.6
Nybro	DK	2%	2.3
Dornum	DE	11%	11.3
Helgoland	DE	5%	5.2
Brunsbuttel	DE	5%	5.2
Maasvlakte	NL	18%	18.5
Ijmuiden	NL	19%	19.1
Den Helder	NL	19%	19.1
Eemshaven	NL	0%	0.5
Zeeland	NL	5%	5.4
Karsto	NO	1%	0.7
Kollsnes	NO	1%	0.7
St Fergus	UK	1%	0.6
Teesside	UK	2%	2.1
Easington	UK	9%	8.8
Bacton	UK	2%	2

4.3.2 Description of scenarios

A number of scenarios are set up which can reflect the future socio-political constraints of installing infrastructure in the NS. The results of these cases are then compared in order to answer the research questions.

Hydrogen networks or electricity grids

Producing hydrogen can be done offshore using electricity from wind, and transported back via a hydrogen network. Or, an electricity grid can transport the electricity from wind to shore, and hydrogen can be produced onshore. These results of these two scenarios are compared to indicate the difference in costs between offshore and onshore hydrogen production. It is unlikely that the future infrastructure will be completely hydrogen or electricity, and so integrated scenarios can also be compared. Here, a percentage of the hydrogen is produced offshore and a percentage is produced onshore. Different percentages of offshore and onshore are compared to see the effects on the cost of producing hydrogen. Importantly, the whole system costs are taken into account as the components of an electricity grid and a hydrogen network varies greatly. The results from these scenarios show the differences in costs of offshore and onshore hydrogen, and answers the main research question, as wel as RSQ1.

Spatial uses and reusing infrastructure

When planning and installing infrastructure, other competing spatial uses and infrastructure must be considered, as well as the effects on the surrounding environment. This is taken into account by applying weighing values to the spatial uses and infrastructure in the NS. Three scenarios can be created based on the existence of these spatial uses and infrastructure. Firstly, a greenfield scenario where no spatial uses or infrastructure is considered, acting as a base scenario. Secondly, the effects of spatial uses is included, by using a cost surface to determine the routing. Lastly, the effects of spatial uses and the possibility of reusing infrastructure is considered. Comparing the results of these scenarios give indications on the limitations and opportunities of existing spatial uses and infrastructure on the routing and costs of transporting energy and producing hydrogen. Additionally, it can show which areas in the NS are favourable for installing energy transport infrastructure, as well as which parts of the existing infrastructure is favourable to reuse. Comparing the results of these scenarios answers RSQ2.

Forced interconnection or isolation

Interconnecting countries via hydrogen networks or electricity grids can be beneficial in terms of trading energy, energy security and flexibility. However, there is (currently) little regulatory support to do this in the NS, which may change in the future. This future uncertainty can be explored by creating an interconnected scenario and an isolated scenario. In the interconnected scenario, a complete network is created between all sources and sinks in the NS, forcing all countries to balance their supply and demand. In the isolated scenario, countries are forced to connect to the sources and sinks within their EEZ, and cannot connect to neighbouring countries. Comparing the results from these scenarios gives an indication of the difference in routing and investment costs of both network set ups. A comparison of the results of these scenarios answers RSQ3.

4.3.3 Structure of scenarios

The above can be summarised as 11 scenarios, sorted in the following structure in Table 7.

Table 7: Structure of scenarios.

Hydrogen production	Spatial complexity	Network set up	Scenario
Offshore (transport via hydrogen network)	Greenfield	Interconnected	*H*
	Cost surface	Interconnected	*HSpa*
	Cost surface & existing infrastructure	Interconnected	*HIInt*
		Isolated	*HIIso*
Onshore (transport via electricity grid)	Greenfield	Interconnected	*E*
	Cost surface	Interconnected	*ESpa*
	Cost surface & existing infrastructure	Interconnected	*EIInt*
		Isolated	*EIIso*
75% offshore, 25% onshore	Cost surface & existing infrastructure	Interconnected	*75H25E*
50% offshore, 50% onshore	Cost surface & existing infrastructure	Interconnected	*50H25E*
25% offshore, 75% onshore	Cost surface & existing infrastructure	Interconnected	*25H75E*

4.4 System costs

To compare scenarios, the length, capacity and costs of networks are calculated. Additionally, the levelized cost of hydrogen (LCOH) are calculated for the whole system. Firstly, the real cost of the optimised infrastructure is calculated. To convert the results of the optimisation into real cost values, two steps are required. Firstly, the cost is calculated through the equation 2, using the length of the infrastructure.

$$Real\ C(G) = X(\sum_{e \in E_n(G)} l_e q_e + cpc \sum_{e \in E_o(G)} l_e(q_e - q_{e,r}) + rpc \sum_{e \in E_o(G)} l_e q_{e,r}) \tag{2}$$

Where the real total cost C of network G is found. This is made up of a set of new edges E_n and existing edges E_o. The individual edges e have a capacity q. Existing edges have a remaining capacity $q_{e,r}$ which has a repurposing cost multiplier rpc and a capacity extension cost multiplier cpc. Although no power cables are available to be reused in the NS, the corridors they provide may be reused at lower costs. In this case, a very low existing capacity is given to these cables to simulate the possibility of reusing the corridor. Lastly, the equation is multiplied by X, which is a real cost factor for new infrastructure. These cost values are derived from internal TNO data, where a number of pipeline and HVDC cable distances are given at a number of different capacities. For each scenario, X changes dependant on the average distance and the capacity of the edges in each scenario. Linear interpolation is used to find each cost value. A comparison of the used cost to literature is seen in Appendix B, where HVDC cable infrastructure costs are compared to the values by Härtel et al. [154] in (Figure 42) and hydrogen pipelines costs are compared to the Danish Energy Agency [151] (Figure 41). The figures show that the values used in this study are in line with the literature. The LCOH is calculated through equation 3 [155, 156, 157]:

$$LCOH = \frac{\sum_{t=0}^{t=T}((\frac{I_s}{(1+r)^t}) + (\frac{FOM_s}{(1+r)^t}) + (\frac{VOM_s}{(1+r)^t}))}{\sum_{t=0}^{t=T} \frac{E_H - EL_s}{(1+r)^t}} \tag{3}$$

Where t is the timestep, T is the system lifetime, and r is the discount rate. I is the investment, FOM is the fixed operation and maintenance costs, VOM is the variable operation and maintenance costs, E_H is the hydrogen energy produced and E_L is the energy losses. The system, s, consists of different components, dependant on the scenario. These component parameters are seen in Table 4 and 5.

- Hydrogen system: OWF, offshore island/platform, offshore desalination unit, offshore electrolyser, offshore compressor, offshore pipelines.
- Electricity system: OWF, offshore cables components, onshore desalinization unit, onshore electrolyser and onshore compressor.

Finally, a conversion of 1 €/MWh H2 to 25.4 €/kg H2 is used [157].

5 Results

This section includes network optimisation outputs, the capacity, lengths and costs of infrastructure, as well as a comparison of system LCOH between all scenarios. The cost surfaces used for each scenario can be found in Appendix C. As a reminder, the scenarios as structured in the following manner as seen in Table 8 below. The hydrogen network and electricity grid costs are not compared to each other in the first sections, as they must be put into context of the whole system.

*Table 8: Scenario summary. The main changes between scenarios are highlighted in **bold.***

Scenario	Description
H	**Offshore hydrogen production, hydrogen network, no spatial complexity (greenfield)**.
HSpa	Offshore hydrogen production, hydrogen network, **spatial uses**
HIInt	Offshore hydrogen production, hydrogen network, cost surface and **existing infrastructure. Interconnected network**.
HIIso	Offshore hydrogen production, hydrogen network, cost surface and existing infrastructure. **Isolated networks**.
E	**Onshore hydrogen production, electricity grid, no spatial complexity (greenfield)**.
ESpa	Onshore hydrogen production, electricity grid, **spatial uses**.
EIInt	Onshore hydrogen production, electricity grid, spatial uses and **existing infrastructure. Interconnected network**.
EIIso	Onshore hydrogen production, electricity grid, cost surface and existing infrastructure determines routing network. **Isolated networks**.
75H25E	**75% offshore hydrogen production, 25% onshore hydrogen production.** Spatial uses and existing infrastructure. Interconnected network.
50H25E	**50%** offshore hydrogen production, **50%** onshore hydrogen production. Spatial uses and existing infrastructure. Interconnected network.
25H75E	**25%** offshore hydrogen production, **75%** onshore hydrogen production. Spatial uses and existing infrastructure. Interconnected network.

Figure 21 below highlights the general trends between the different scenarios, when compared to their base scenario (*H* for the hydrogen scenarios and *E* for the electricity scenarios). For hydrogen , the network costs are pipelines and compressors. For electricity, it is the HVDC cables, converters, offshore platforms and onshore stations. In the hydrogen scenarios (left), it decreases by around 50% when including the spatial uses (*HSpa*), but increases by around 10% for the *HIInt* and *HIIso* scenarios. For the electricity scenarios (right), the share of network costs in the LCOH increases greatly by nearly 100% when including spatial complexities (*Espa*). It is still 70% higher when reusing infrastructure and interconnected (*EIInt*). The costs are significantly less when isolated (*EIIso*), but still 20% higher than the base scenario. These trends are explained further in the sections below.

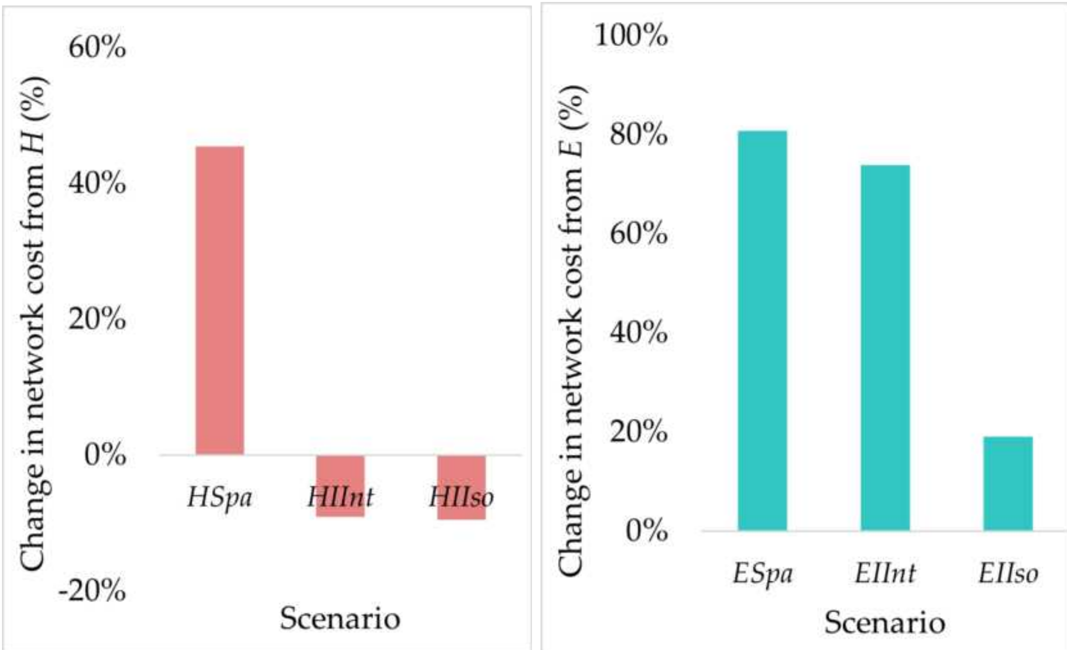

Figure 21: Relative change in network costs for hydrogen scenarios (left) and electricity scenarios (right). The hydrogen scenarios are compared to the base scenario 'H', while the electricity scenarios are compared to the base scenario 'E'.

5.1 Spatial complexity

When including spatial complexities and creating a cost surface, the network costs increase for all scenarios. For the hydrogen scenario, this is due to the significant increase in network capacity-length, as highlighted in Table 9 and Figure 22. The total infrastructure capacity length (TICL) increases as the routing network must navigate around the spatial uses in the NS in the *HSpa* scenario, in comparison to the *H* scenario. This similarly happens for the respective electricity scenario (*ESpa*).

Figure 22a and b shows the results when a greenfield approach is used, where no spatial uses are considered and the optimiser connects the sources and sinks without use of a routing network (*H,E* - greenfield). The resulting hydrogen network is short, with large capacity pipelines of > 18 GW seen along the east coast of the UK, through the west and north of the Dutch EEZ and in the north of DE and DK. Interestingly, some OWF act like hubs for connecting multiple other farms, such as Search Area 1 in the west of the Dutch EEZ, or NS2 L10 in the south of the Danish EEZ. Most countries have a direct connection to their own OWF, with the exceptions of DE, where the OWF are firstly connected to the Dutch and Danish OWF. Also noteworthy is the smaller capacity connections (< 1 GW) to NO and DK, as their predicted hydrogen demand is much lower.

The electricity grid looks very different to the hydrogen network, resulting in a star-like network with very long distance connections (such as Scotland to BE/NL) as seen in Figure 22b. These connections must be made to ensure that total supply = total demand across the network. The change in topology compared to the hydrogen network is due to the different cost-capacity exponent used for the scenarios. Electricity cables are given a value of 1, assuming that a linear cost-capacity relationship, with no cost benefits of using higher cable capacities. Pipelines are assigned 0.6 meaning that increasing capacity results in significant cost benefits. This explains the different network design in *H* and *E*, and why the capacity-length is greater for the hydrogen pipelines.

The hydrogen pipeline capacity-length increases and routing changes significantly when considering spatial uses as is seen in Figure 22c. Now, a large pipeline connection (10 GW) is seen from the east of the UK, travelling to the centre of the NS where it connects with the Norwegian and Danish OWF. This seems to be done in order to circumvent the high societal-cost ecological area (Doggers Bank) in the EEZ of the UK and NL. This carries on into the German EEZ where a major branch (18 GW) forks into the Dutch EEZ. In the UK, this major pipeline also splits into a tree-like structure with capacities of between 5 - 8 GW to connect the sources and the sinks.

When comparing the hydrogen network to the electricity network with spatial uses (Figure 22d), it is seen that they are very similar. However, a big difference is that NL is connected directly to the UK via a 9 GW connection, which did not exist previously. This is caused by the differences in the cost surfaces (see Appendix C). For *ESpa*, lower cost areas are defined in the south of the UK EEZ, where locations have been designated for installing power cables. Therefore, the model prefers these routes in comparison to the *HSpa* scenario, making connections like the one to Teesside (most central UK sink). On the other hand, in DK, areas have specifically been designated for future pipelines, which means this route is preferred by the model for the *HSpa* scenario, such as the connection made to the Danish sink (Nybro). The effects of the cost-capacity coefficient is also highlighted in the Figure 22d, where numerous additional connections are seen in *ESpa* compared to *HSpa*, such as the second connection to the Norwegian sinks. Interestingly, the capacity-lengths are greater for the electricity grids compared to the hydrogen networks in these scenarios. The reason for this is as there are more preferred routes for cables in the NS in comparison to pipelines. Thus, more deviations are made by the electricity grids to follow these lower-cost routes, resulting in a longer distance.

Table 9: Summary of total infrastructure capacity lengths (TICL) and total network costs for H, E, HSpa and ESpa scenarios.

Scenario	*H*	*HSpa*	*E*	*ESpa*
Infrastructure type	Pipeline	Pipeline	Cable	Cable
TICL (TWkm)	32	48	27	52
Network cost (B€)	15	22	87	113

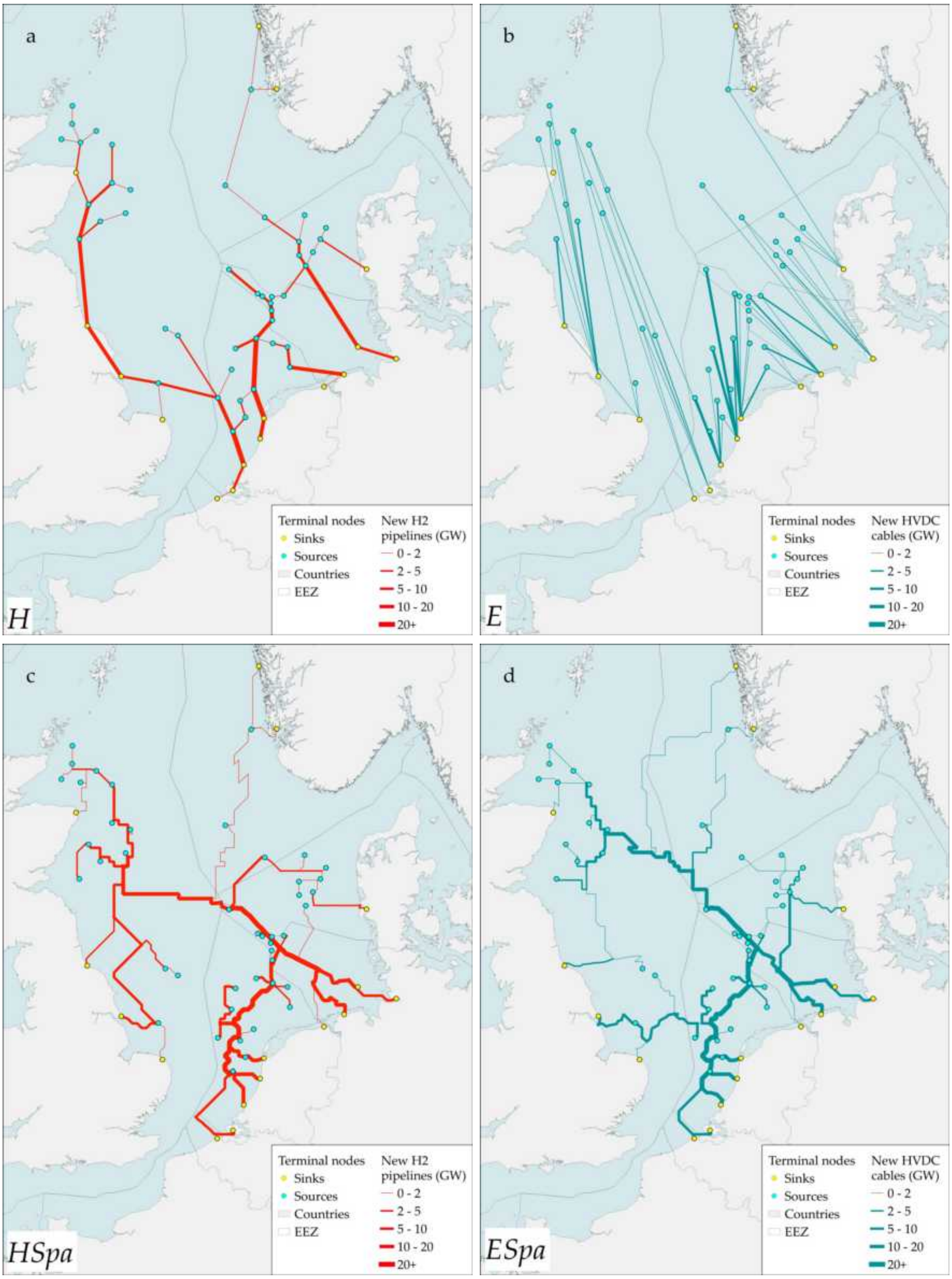

Figure 22: a) Scenario H and b) scenario E (greenfield). c) Scenario HSpa and d) Scenario ESpa, where spatial uses are considered.

5.2 Reusing existing infrastructure

For hydrogen networks, reusing pipelines significantly decreases network costs in comparison to the scenario with spatial uses (*HSpa*). It is even slightly less than the base scenario (*H*). This is because large parts (80%) of the network are created from reusing existing pipeline or reusing corridors, as is shown by the TICL in Table 10 and Figure 23. Reusing existing pipelines provides a cost saving of 90%. For electricity grids, savings are made in comparison to the respective scenario with spatial uses (*ESpa*) as significant amounts of electricity cable corridors are reused (around 60% of the network). However, it is still costlier than the base case (*E*), as the corridor savings are not that significant (22%) and the TICL is much higher.

Figure 23a below shows the hydrogen network when it can reuse the existing infrastructure. Major connections of > 10 GW are now seen from the north of the UK EEZ to the Dutch and Norwegian EEZs, using large parts of the existing O&G network. The Danish and German OWF are more isolated and robustly interconnected with each other (with connections of > 5 GW), but very weakly connected to the rest of the NS hydrogen network (connections of < 1 GW). Interestingly, the Norwegian OWF are not directly connected to the shore, and instead receive their energy from the Danish OWF, which connects to the existing pipeline (of 0.9 GW). Notably in the Dutch EEZ, hydrogen pipelines are almost exclusively consisted of reusing old infrastructure, signifying the reuse potential in this area. Lastly, many of the O&G pipelines require capacity upgrades as they cannot transport all of the produced hydrogen from the vast amount of OWF capacity. This is highlighted in Table 10, where around 60% of the reused pipelines also reuse the pipeline corridor.

Although there are no reusable electricity cables in the NS, it is possible to reuse cable corridors. This is why the electricity grid in Figure 23b differs greatly to the pipeline network as well as the electricity network seen in Figure 22d. The previous large connection between the German EEZ and the UK EEZ is not used, and instead a large (19 GW) connection takes place from the north to south corridor in the UK. This then connects to the Norwegian and Danish EEZs from the south (with capacities of > 11 GW). The Dutch and Belgian OWF also share a common connection (of 38 GW) which joins the Danish and German EEZ. Similarly to the hydrogen network, the Norwegian sinks benefits from connections (0.1 GW) from another country, this time being the UK.

Table 10: Summary of TICL for HIInt and EIInt scenarios.

Scenario:	*HIInt*	*EIInt*
Infrastructure type	Pipeline	Cable
TICL (GWkm)	68	54
TICL (reuse) (GWkm)	39	
TICL (corridors) (GWkm)	18	34
Network cost (B€)	14	113

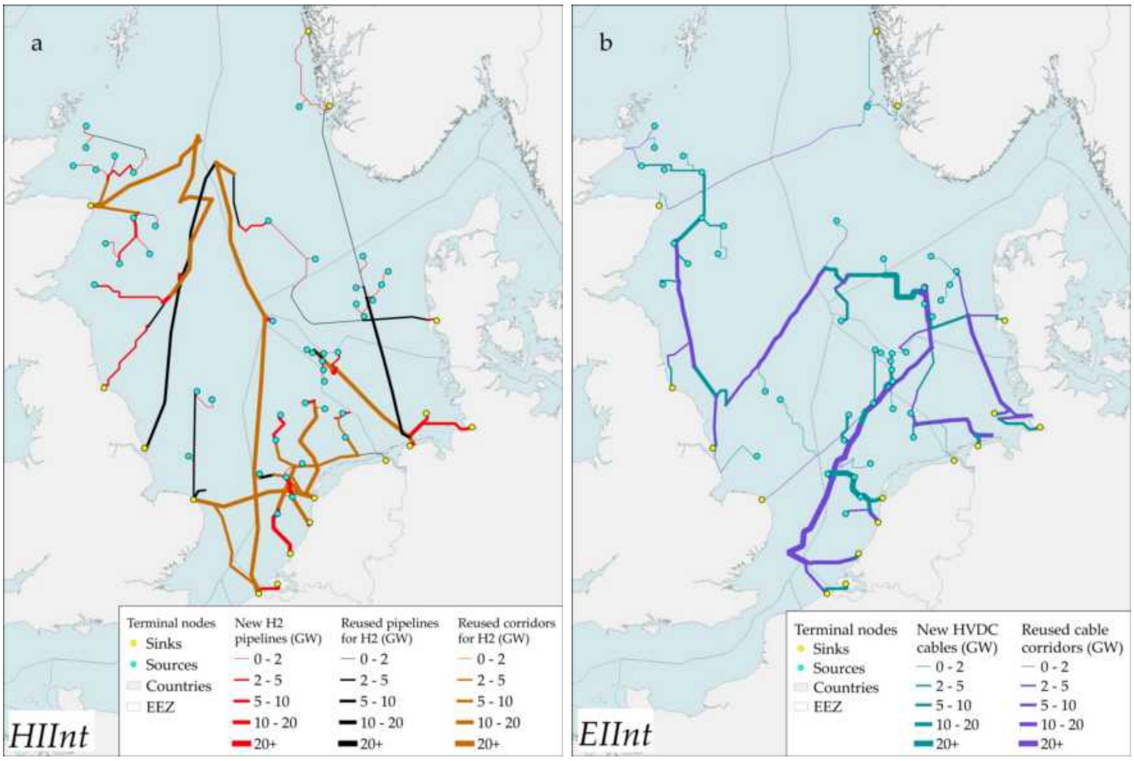

Figure 23: a) Scenario HIInt and b) Scenario EIInt.

5.3 Isolated networks

For hydrogen networks, forcing isolation of networks between countries has no significant effect on the costs when compared to the *HIInt* scenario. This is counterintuitive, as the TICL is much lower in the *HIIso* scenario, as Table 11 and Figure 24 highlights. However, the amount of reused pipelines is also lower (less cost savings than *HIInt*), and the amount of reused corridors is higher (higher costs than *HIInt*). This means that the network costs between both scenarios stays very similar. The *HIInt* scenario increasingly benefits from the existing interconnection between countries (from the O&G network). For the electricity grid, forcing isolation (*EIIso*) results in a lower cost than in *EIInt* as the distance of the network is much less, and the cost saving benefits from reusing corridors (in *EIInt*) is not significant enough. Another factor which benefits the isolated scenarios is that a hydrogen grid or electricity network is not considered for BE, as no sources were included in the input data. This means that the cost decreases very slightly due to no connections being made in the Belgian EEZ. However, this cost saving is (relatively) negligible; around 0.6 B€ for the electricity grid and 0.1 B€ for the hydrogen network.

The isolated networks are seen below in Figure 24. Here, countries are only allowed to connect to the sources and sinks which are within their EEZ. In the Danish and German EEZs, the networks are similar in both the isolated scenarios (*HIIso* and *EIIso*). However, in the other countries, the hydrogen network is very different due to reusing a lot of the existing pipeline infrastructure. For example, in the UK EEZ, the TICL of pipelines are much larger than the cables, as shown in Table 11. When comparing *HIIso* to the *HIInt*, similarities are seen such as the reuse of pipelines in the east of the UK EEZ, as well as the Dutch and German pipelines. However, the pipeline distance is much smaller. A considerable change is in the Norwegian EEZ, where the country's sources must now connect to its own sinks, rather than the other OWF in the NS. Additionally, it is not possible to reuse the large central pipeline corridor which travels along the border of all the EEZs.

Table 11: Summary of (total) infrastructure capacity lengths ((T)ICL) and for HIIso and EIIso scenarios.

Scenario:	*HIIso*					*EIIso*				
Infrastructure type:	Pipeline					Cable				
Country	NL	DE	DK	NO	UK	NL	DE	DK	NO	UK
ICL (TWkm)	13	7	1	3	24	14	7	2	1	17
ICL (reuse) (TWkm)	4	3	0	2	9					
ICL (corridors) (TWkm)	5	3	0	0	13	4	0	1	1	13
TICL (TWkm)	49					34				
TICL (reuse) (TWkm)	17									
TICL (corridors) (TWkm)	21					8				
Network cost (B€)	14					93				

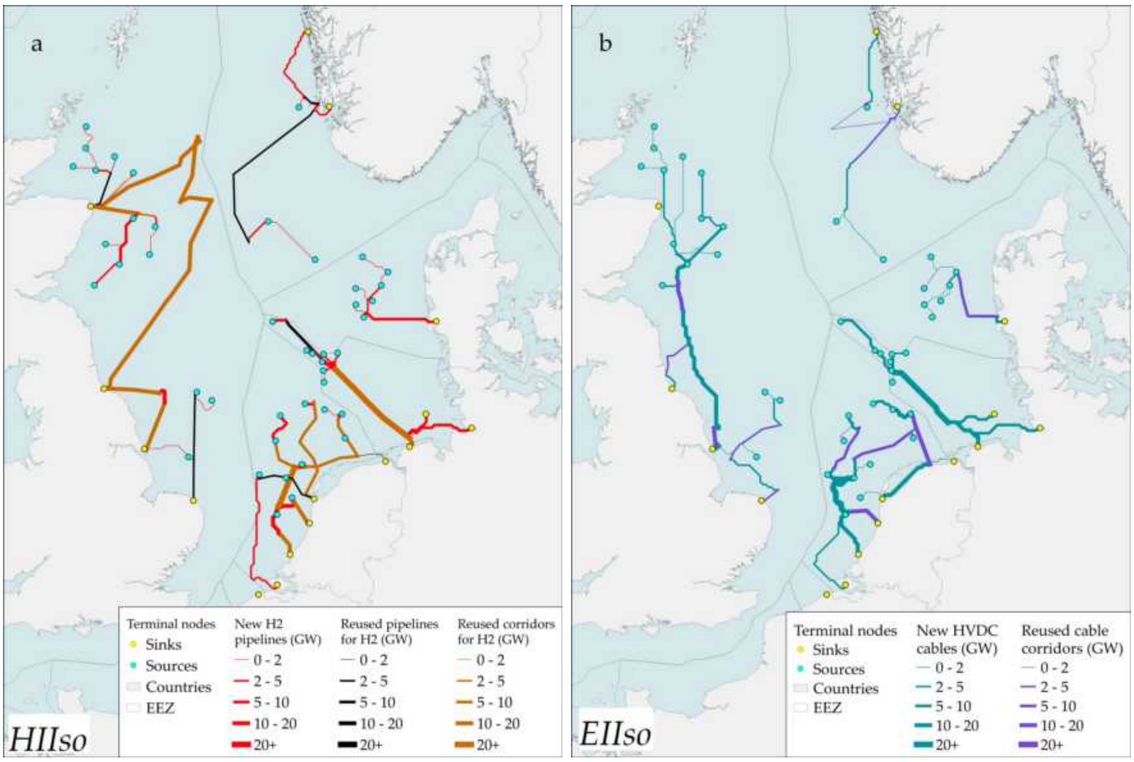

Figure 24: a) Scenario HIIso and b) Scenario EIIso.

The isolated electricity grid (*EIIso*) is also much shorter than the interconnected electricity grid (*EIInt*) (in Figure 23b), with the removal of the large connections (> 10 GW) seen from DK through DE and NL to the UK. The Danish network stays quite similar, whereas the Norwegian network is completely changed again, being forced to connect to its own sinks. Similarly, in the German EEZ, a large trunkline (22 GW) is now created connecting its far offshore sources to the offshore sinks. Interestingly, this is similar as to the *HIInt* scenario in Figure 23a, and is likely caused by the large preferred cable & pipeline route area set in the German MSP.

The effects of interconnecting compared to isolation for the individual countries are shown in Figure 25 (hydrogen) and Figure 26 (electricity) below. It is assumed that each country must pay for the technology installations which takes place in their own EEZ. Appendix C details the TICL changes for each country. In the graphs, a positive change from *IInt* to *Iso* means that the system LCOH increases from the isolated to the interconnected scenarios. Also, a positive deviation from the average *IInt* cost means that the country has a higher LCOH than the average.

For the hydrogen networks, it is seen that DK minorly benefits from interconnection (*HIInt*) rather than isolated network (*HIIso*), as they are able to reuse more pipelines at low costs. NL and especially NO has the opposite, where the LCOH is 17% lower with isolated networks. This is likely due to the large capacities (2 – 10 GW) of pipeline seen in the Norwegian EEZ, while it does not have a large hydrogen demand (1.4 GW) or supply (1.5 GW). The figure also shows that DE and DK would pay slightly less than the average network costs in the *HIInt* scenario. This is because the UK and NO pay larger shares, due to large parts of the network being in their EEZ, which is at no extra benefit to them.

For the electricity scenarios (Figure 26), slightly different trends are seen. All countries benefit from having isolated networks (*EIIso*) instead of interconnected networks (*EIInt*), following the trends seen in Table 10 and 11, where isolated electricity grids are cheaper than interconnected electricity grids. Interestingly, an isolated grid for DE is nearly as cost-effective as an interconnected grid, due to being able to reuse more corridors in this scenario (see differences in German EEZ in Figure 23b and Figure 24b). DE, NL and UK slightly benefit from a below average LCOH, whereas DK and NO have very large increases of 100% to 130%, respectively. This is due to both countries having to invest in very large connections (> 18 GW) in comparison to their hydrogen supply and demand (< 7 GW per country).

Overall, the effects on LCOH in the hydrogen scenarios are very small (besides NO), with only changes of a few percent. The effects are more pronounced in the electricity scenarios, as changes in network design have greater effects on the cost. In both scenarios, countries with greater OWF capacity such as the NL are least affected, while countries with the least OWF such as DK and NO are more affected. A small capacity of OWF means the LCOH is more sensitive to changes in system cost.

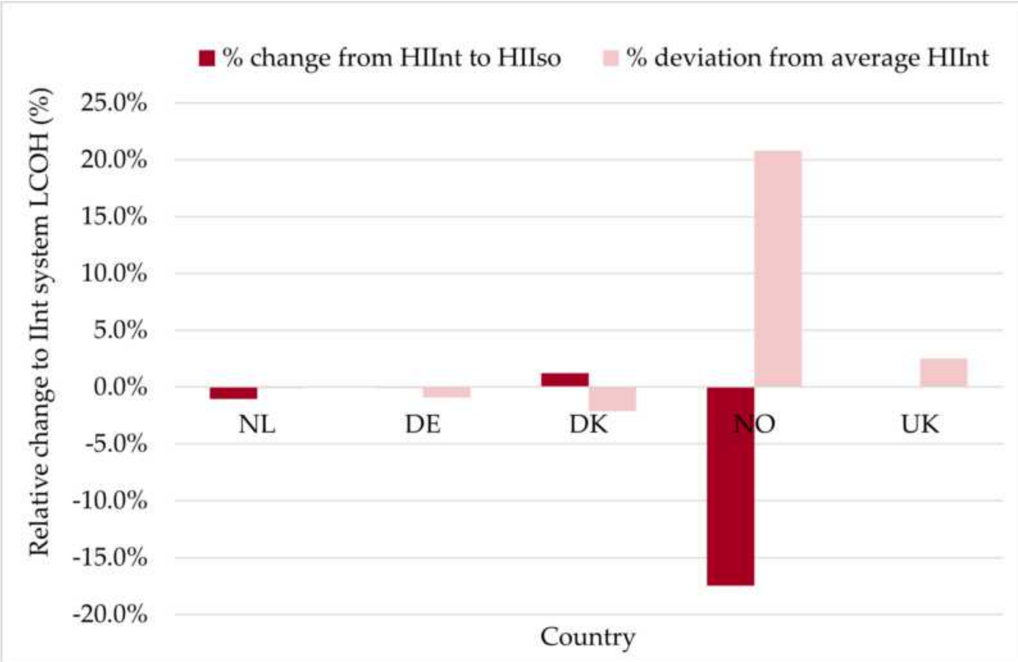

Figure 25: Hydrogen networks cost changes per country. In red (left columns), the % change in LCOH from an interconnected network (HIInt) to an isolated network (HIIso). In pink (right columns), the % deviation in LCOH from the average LCOH of the interconnected (HIInt) scenario.

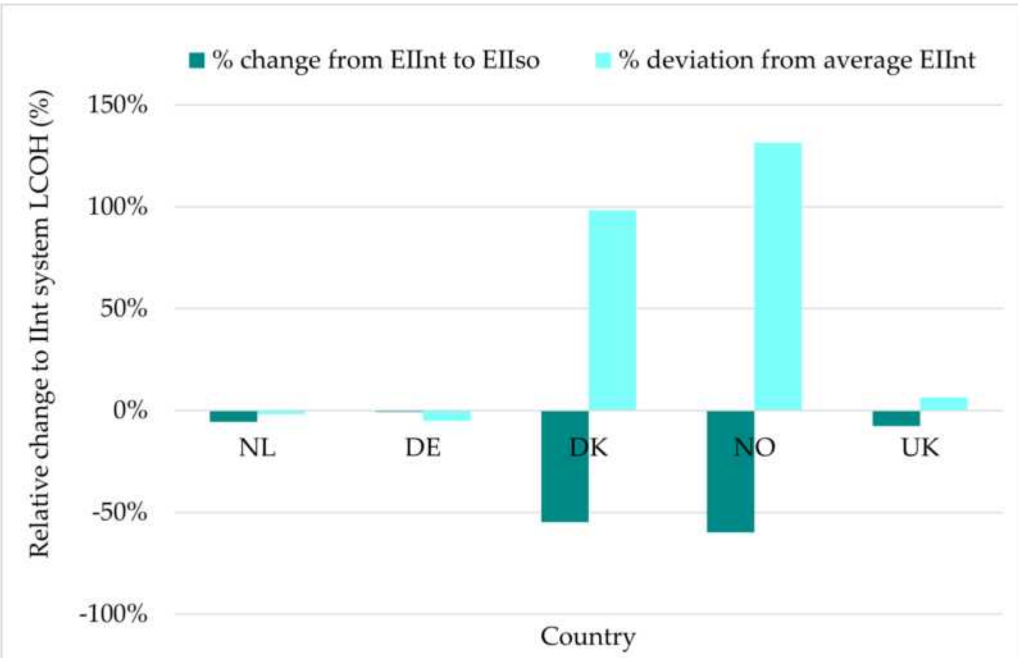

Figure 26: Electricity grids costs changes per country. In green (left columns), the % change in LCOH from an interconnected grid (EIInt) to an isolated grid (EIIso). In blue (right columns), the % deviation in LCOH from the average LCOH of the interconnected (EIInt) scenario.

5.4 Levelised cost of hydrogen

Figure 27 shows the LCOH results from the different scenario runs, along with the breakdown of the system components. For a full breakdown, see Appendix C. The changes between the scenario types for both the hydrogen and electricity scenarios (*..., Spa, IInt and IIso*) match the results seen in the previous sections. Interestingly, the LCOH between all hydrogen and electricity scenarios is very similar, with only a 10% change between the highest and lowest. It is notable (as Figure 28 shows) that the costs of the hydrogen network have a very small share of the total LCOH ($< 4\%$), whereas the HVDC cables have a much larger share (30%). This is what causes a greater variance in the electricity scenarios compared to the the hydrogen scenarios in Figure 21. Nevertheless, the significant cost savings of using hydrogen pipelines instead of HVDC cables is counteracted by the high costs of the electrolyser platforms. Although the changes between scenarios are very small, some trends can be seen. The *HIInt* scenario is slightly less expensive than the *EIInt* scenario, due to the decrease in network costs of reusing infrastructure. However, the *EIIso* scenario is less expensive than the *HIIso* scenario, due to the investment costs saved through isolated networks. Lastly, the *E* scenario is cheaper than the *H* scenario. Comparing this last finding to all other scenarios, it highlights how the electricity scenarios are penalised to a greater extent for increases in capacity-lengths, when comparing to the hydrogen scenarios.

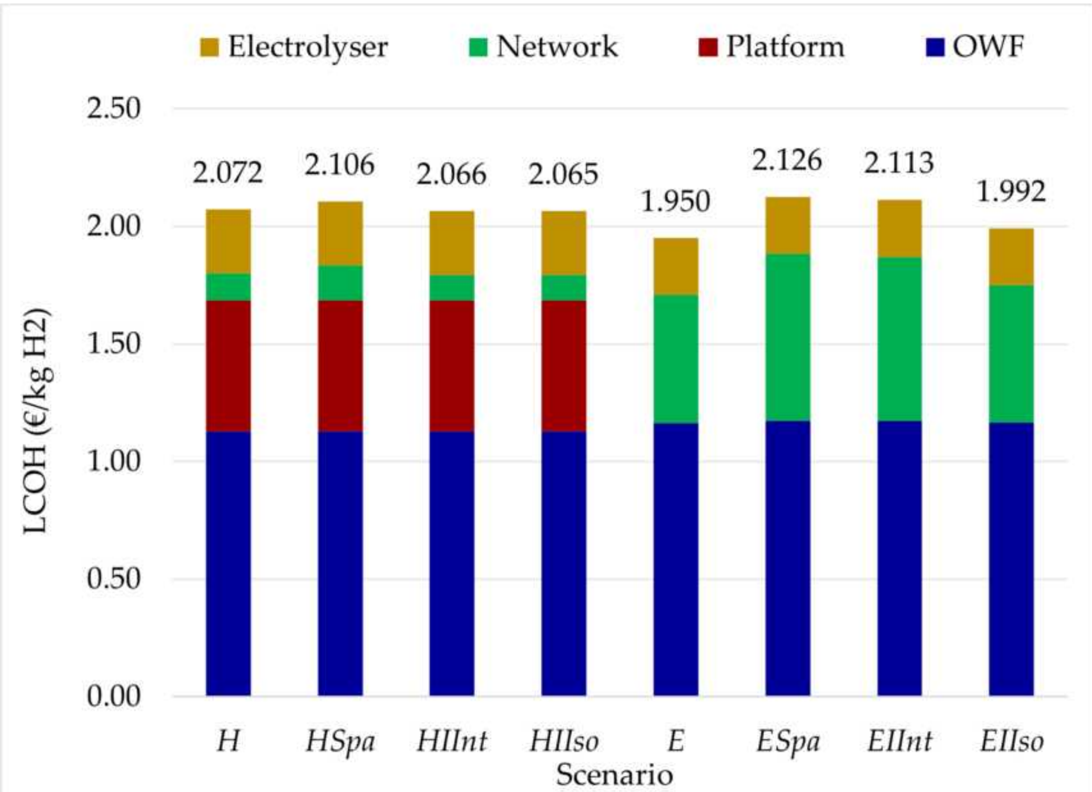

Figure 27: LCOH breakdown of all hydrogen-only and electricity-only scenarios.

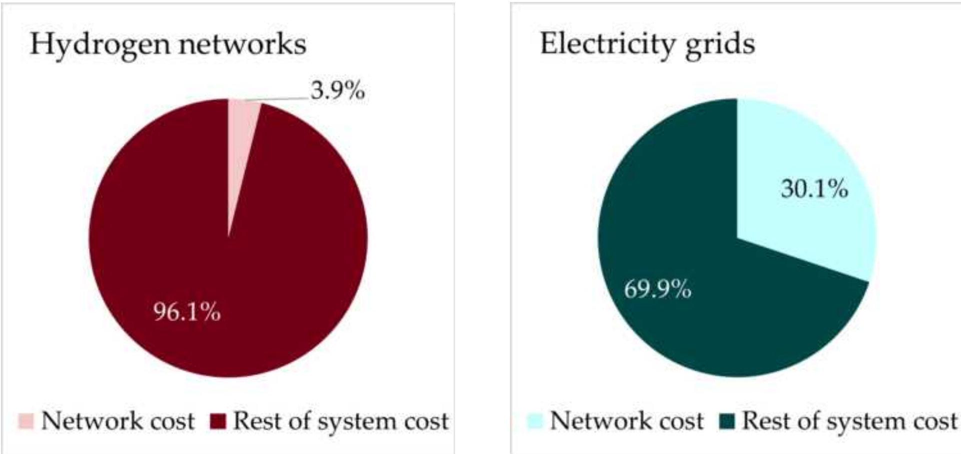

Figure 28: Average share of network costs in LCOH for hydrogen (left) and electricity scenarios (right).

Due to the small changes in LCOH in all hydrogen-only and electricity-only scenarios, the integrated scenarios also change very minorly (as Figure 29 shows), increasing the LCOH of 0.7% when meeting half of the hydrogen demand on- and offshore. Interestingly, the costs increase slightly non-linearly with increased share of electricity. This is due to the network costs, where increasingly less savings are made moving away from using lower capacity hydrogen pipelines. The final mapped results of the integrated networks can be found in Appendix C.

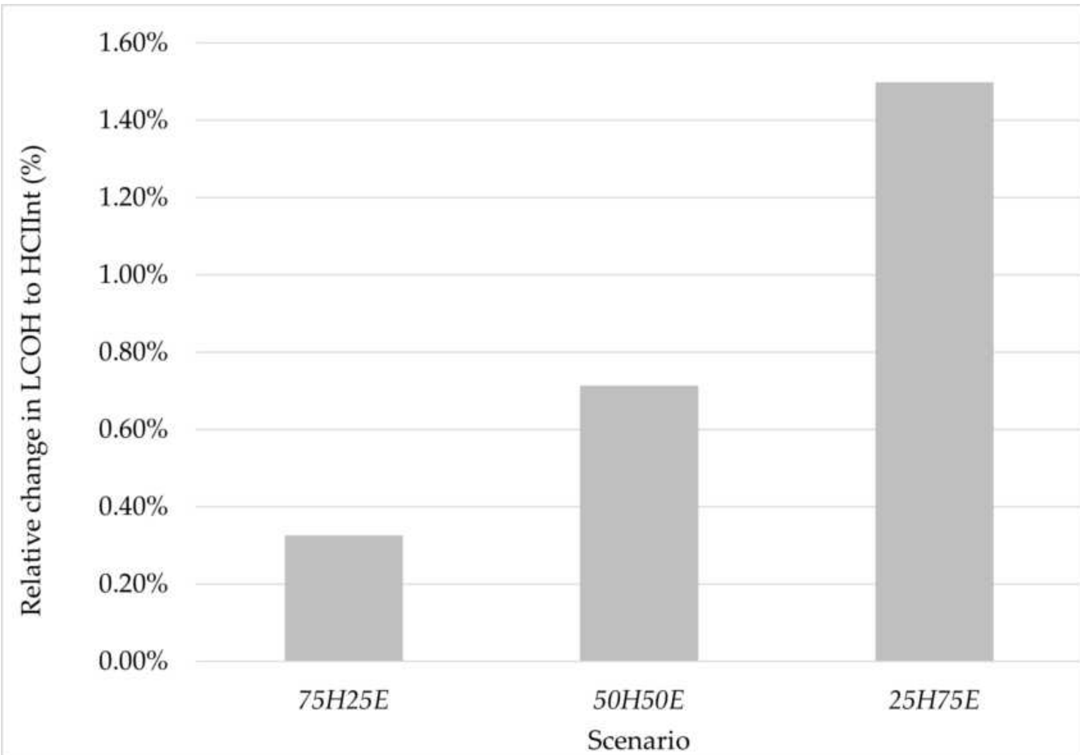

Figure 29: Change in system LCOH for integrated scenarios, using HIInt as base scenario. H = hydrogen, E = electricity, numbers are percentages.

5.5 Sensitivity analysis

Sensitivities are present in the modelling methodology due to the manual selection of onshore sinks and the LCP and cost surface approach, which may cause unnecessary increases in capacity-lengths of the produced networks. In the post-optimisation cost calculation, significant uncertainties are present as the future technology costs and system design are highly predicted, which can affect the costs of on- or offshore hydrogen production. To investigate the effects on the different outcomes, a number of inputs and system components are varied. The scenario summary is seen in Table 12.

5.5.1 Sensitivity scenarios

Onshore transmission

It is likely that onshore transmission of hydrogen will also take place between sinks and between countries. However, reliable data on onshore pipeline locations and capacities is not readily available. Therefore, onshore connections are manually created in the existing infrastructure and are assigned high capacities. The connections are roughly based on the repurposed existing O&G pipelines defined in the European Hydrogen Backbone [59], as well as an estimation of the available capacity using the ENTSOG map [82]. Using the best scenario *HIInt* as a base, the optimisation is reran, creating an onshore transmission case (*OnHIInt*).

Offshore hydrogen components

The cost of installing and maintaining offshore hydrogen components is not well known and highly predicted, as no large scale (multi-GW) projects are (currently) planned or completed. An offshore cost multiplier is assigned to all offshore components to see its effects on the cost. Specifically, this multiplier is assigned to platforms (for electrolysers), offshore desalination units, offshore electrolysers and offshore compressors. Offshore cost additions of 25% and 50% are used (similarly as in [27]). Additionally, a scenario is created to reflect the possible decrease in costs of sandy energy islands (0.5 M€/MW electrolyser capacity) over electrolyser platforms (0.9 M€/MW electrolyser capacity) [21]. The best scenario (*HIInt*) is used as a base case, creating the sensitivity scenarios *IslHIInt*, *25HIInt*, and *50HIInt*.

Network costs

As the optimisation output maps show, there are overestimated bends in pipelines and cables in all scenarios, due to the LCP modelling technique. To account for these, we can assume a length correction factor (LCF) of dividing the lengths with $\sqrt{2}$, which gives the diagonal (Hypotenuse) length of a right angled turn. This is done for *HIInt* and *EIInt*, giving the sensitivity scenarios *LCFHIInt* and *LCFEIInt*, respectively. Additionally, it is assumed in this study that no significant cost-benefits are seen from increasing cable capacity. An economic scaling factor of 0.8 is applied using the costs of the current largest HVDC cable (2 GW), where increases in capacity lead to cost benefits. This is done for the *EIInt* scenario, creating *0.8EIInt*.

Table 12: Summary of sensitivity scenarios.

Sensitivity scenario	Description
OnHIInt	Onshore reuse of O&G infrastructure is allowed.
IslHIInt	Energy island costs used for electrolyser platforms.
25HIInt	Offshore hydrogen components have a cost addition of 25%.
50HIInt	Offshore hydrogen components have a cost addition of 50%.
LCFHIInt	Pipelines are corrected for overestimated bends.
LCFEIInt	Cables are corrected for overestimated bends.
0.8EIInt	Cables are applied a cost scaling factor of 0.8.

5.5.2 Sensitivity analysis results

Figure 30 shows the effects of changing the parameters on the system LCOH. As the graph shows, the *OnHIInt* scenario is not significantly different to the *HIInt* scenario, with only a very minor change in cost. Table 13 and Figure 31 below detail the changes. When using the energy island cost factor (*IslHIInt*) significant savings are made, with the system becoming cheaper than the lowest cost electricity scenarios (*E* and *EIIso*). However, if the hydrogen components are underestimated by 25% (*25HIInt*) they become slightly more expensive than the *EIInt* scenario. If this increases to 50% (*50HIInt*), then the hydrogen system becomes significantly more expensive. This is due to the large share of platform costs in the LCOH, as shown in Figure 27. When the LCF is used, there are very small savings for the hydrogen system LCOH (*LCFHIInt*). However, when using the LCF for the electricity grid LCOH (*LCFEIInt*), the LCOH breaks even and becomes slightly cheaper than *HIInt*. This is due to the high costs of the electricity cables in comparison to the hydrogen pipelines, where larger savings are made with decreases in distance. Lastly, when applying the scaling factor to electricity cables *0.8EIInt*, the savings are not that significant, and the costs are still minorly higher than *HIInt*.

Table 13 highlights how the *OnHIInt* scenario has a lower system and network LCOH cost, as more pipelines are reused at low costs. However, the costs only show a 0.4% change in the system LCOH, with a 13% change in the network LCOH. This is because the *OnHIInt* reuses more pipelines than the *HIInt* scenario, as shown in Table 13. In terms of the routing, Figure 31 below shows the different outcome of allowing onshore transmission. Comparing this to *HIInt* (Figure 10a), all sinks besides St Fergus in the north of the UK have an onshore connection. However, most sinks also have an offshore connection as well, excluding sinks such as Kollsnes (NO's northernmost sink) and Brunsbüttel in DE. In NL, the network design changes significantly, where Zeeland, Maasvlakte and Ijmuiden have no offshore connections. The main large (> 18 GW) onshore connections are seen in the south east of the UK which connects to BE, as well as Zeeland and Maasvlakte in the south of NL. Additionally, sizable (> 8 GW) connections are seen along the

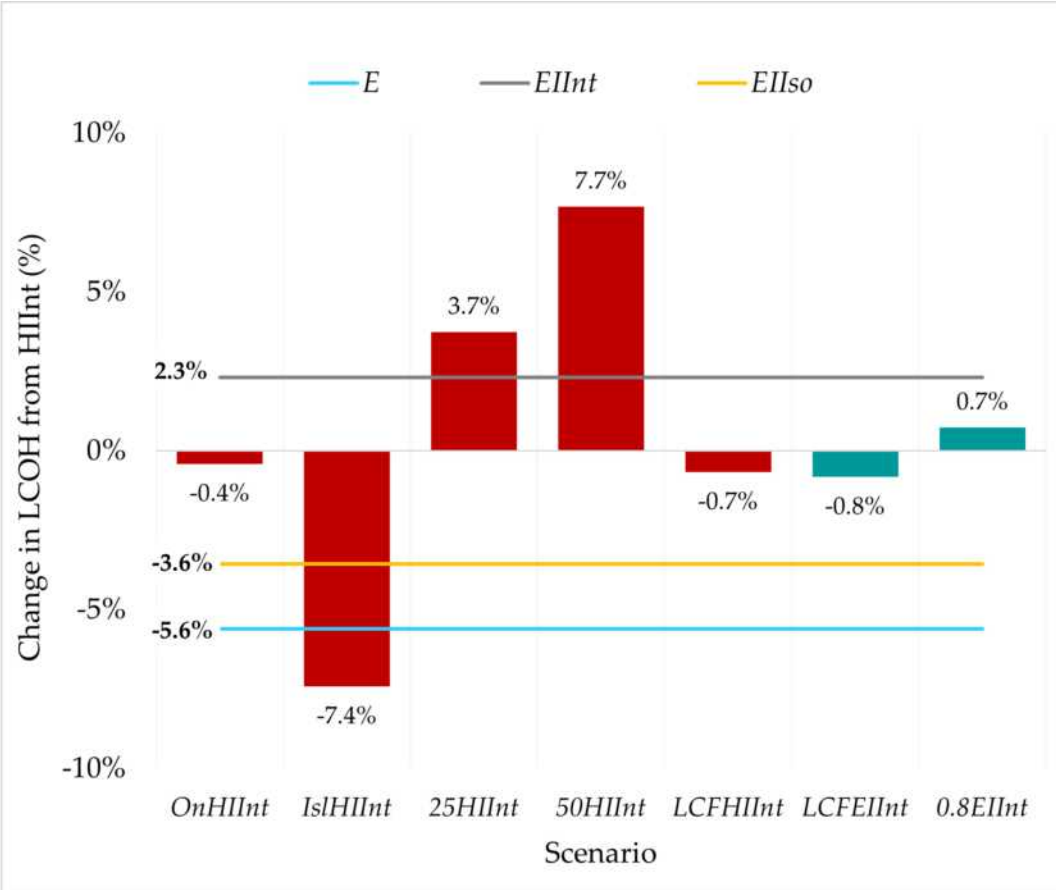

Figure 30: LCOH breakdown of sensitivity scenarios, compared with hydrogen (HIInt) and electricity (E, EIInt, EIIso) scenarios. HIInt is used as the base, with a value of 2.07 €/kg. The hydrogen sensitivity scenarios are on the left (red) and electricity sensitivity scenarios on the right (green).

north coast of NL, connecting also to Dornum in DE. Overall it can be seen that both the onshore and offshore components of hydrogen is likely to play a significant role in a NS-region hydrogen network.

Table 13: Statistics of OnHIInt and the change compared to HIInt scenario.

Parameter	*OnHIInt*	% change to *HIInt*
Infrastructure type:	Pipeline	
System LCOH (€/kg):	2.06	-0.4%
Network LCOH (€/kg):	0.10	-13%
TICL (TWkm):	77	13%
TICL (reuse) (TWkm):	53	35%
TICL (corridors) (TWkm):	19	5%

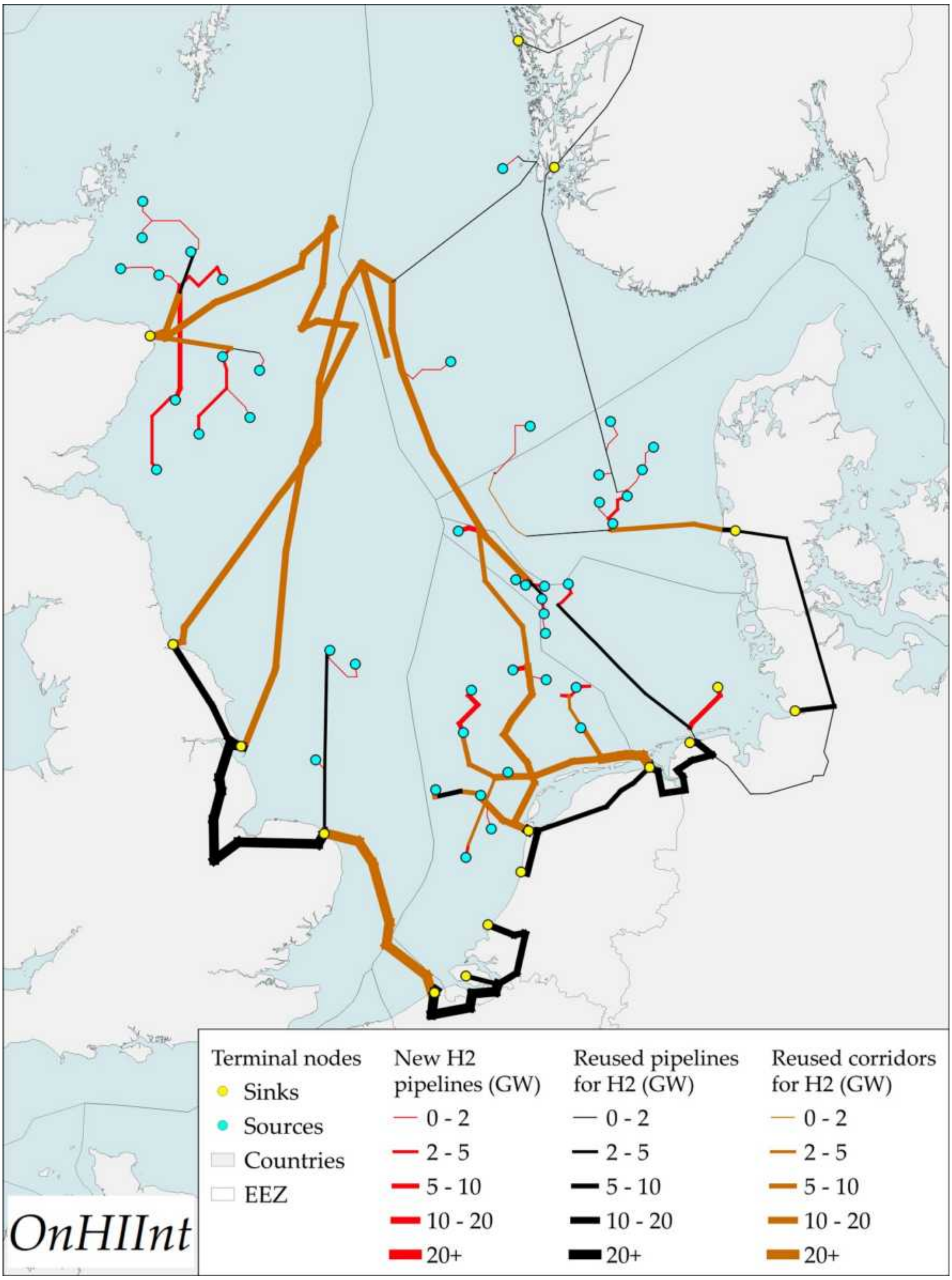

Figure 31: Effects of allowing reuse of onshore O&G pipeline for hydrogen network.

6 Discussion

6.1 Results

6.1.1 System costs

The cost results suggest that hydrogen networks are cost-competitive with electricity grids to transport offshore wind energy to shore, when hydrogen is the end use. This is supported in the literature [20, 23, 25, 24]. The main driver for this result is that the electricity grids have high costs of long-distance, large-capacity connections in comparison to hydrogen pipelines. For hydrogen, the main cost is due to the offshore hydrogen components, namely the electrolyser and electrolyser platform. However, as the sensitivity analysis highlights, there are many uncertain parameters which can sway the costs slightly in favour for electricity grids or for hydrogen networks. Thus, it is unwise to conclude that either one of the systems is undoubtedly cheaper than the other. Nevertheless, an interesting overarching finding from these comparisons is that even with uncertainties and sensitivities, the costs between the systems stay reasonably similar. This suggests that both options could be attractive from an LCOH perspective, and that other socio-economic and energy system aspects are more important to consider in further analysis.

One of these aspects is the uncertainty of large-scale hydrogen production and transportation, due to the immaturity of the technologies. It is assumed that over 100 GW of electrolyser capacity can be installed in the NS between 2040 and 2050 which is challenging, considering that the EU only have goals of 40 GW of electrolysers by 2030 [39]. For example, the extraction rate of iridium, a rare metal used for PEM electrolysers, currently limits the production rate of electrolyser to 3-7.5 GW/year, at a technical maximum [158]. Although cost decreases are expected due to learning and economies of scale, increases in demand could also cause material scarcity and drive up costs, resulting in more expensive offshore hydrogen networks. Although much work has been done by the NSE programmes, the costs of offshore electrolysers and platforms are still highly estimated. On the other hand, the costs for offshore platforms for electrolysis could be significantly less if considering sandy energy islands as is captured in the *IslHIInt* scenario in the sensitivity analysis, where offshore hydrogen network costs become competitive with the lowest-cost electricity grid scenario (E). It would be beneficial to see the final cost effects of larger offshore hydrogen pilot projects in the future such as H_2OpZee. Learning this project, policies could be developed to either support (through subsidies) or limit the commercialisation of offshore hydrogen (networks), dependant on the outcomes.

Bringing electricity to shore has added value as it can provide more flexibility in the energy system, as is similarly argued by the German TSOs in the discussion on offshore hydrogen [142]. It can be used directly, stored in batteries or converted to hydrogen, depending on the demands and opportunities of the surrounding environment. This added value of bringing electricity to shore is not considered in this analysis, but should be considered if looking at the whole energy system. Hydrogen also offers this flexibility, but at increased energy losses, due to the low efficiency of converting hydrogen back to electricity. For example, converting from electricity to hydrogen to electricity results in losses of around 50% [159], whereas bringing electricity to shore (in this study) leads to losses of only 3.5%.

Knowing this, it suggests that integrating hydrogen networks and electricity grids is beneficial, simultaneously providing the benefits of both systems, such as cost savings from the hydrogen network and flexible supply from the electricity grid. The effects of integrated networks on total cost were investigated, showing minute increases in cost due to the similarity of the LCOH for both systems. This reinforces the case for system integration, and following research could expand on this by creating integrated grids based on different sources in the NS to explore potential cost-savings. For example, an electricity grid could be created from sources which are less than a certain distance from shore (e.g. 100 km [21, 16]), while a hydrogen network is created with remaining, far-offshore sources. To go a step further, a hub-and-spoke concepts as suggested by the NSWPH [160] could be used to lower infrastructure capacity-lengths, instead of two fully connected electricity and hydrogen networks, as analysed in this study. Also left out of the scope of this analysis is the potential of offshore salt cavern storage, which could provide additional benefits such as energy flexibility and storage for hydrogen, which were not captured in this study.

Comparing the final LCOH results to the literature, it is seen that the costs are moderately lower, as shown in Figure 32 below, ranging between 1.95 to 2.15 €/kg H2. Importantly, the cost values found from this study are more useful for a comparing to each other rather than to other studies, as the goal is to show the differences between network designs. Nevertheless, the costs in this study are lower due to using 2040 techno-economic value estimates of OWF and electrolysers, which leads to lower total system costs and higher amounts of hydrogen production. For example, the study by Yan et al. [24] considered OWF costs in 2020, whereas this study uses 2040 estimates from the Danish Energy Agency. Interestingly, when comparing the *50H50E* and *EIInt* scenario with the *6GW/4GW* and *10GW onshore* scenarios defined in a report on grid-integration power-to-gas [160], the trends are the same in both studies. The costs between an integrated scenario and purely electric scenario are very similar, with the integrated scenario leading to slightly lower costs.

For hydrogen pipeline transportation, the LCOH for transportation varies between 11 (reused pipelines - *HIInt*) to 15 (new pipelines *HIIso*) c€/kg H2 over a distance of 4000 to 8000 km. This is less than the cost seen in the recent EHB report, where offshore pipelines have a LCOH between 17 to 32 c€/kg H2 over a distance of 1000 km [59]. The costs in this study are less because:

1. The average pipeline size is greater in this study than the three capacities considered in the EHB, leading to a lower average cost.

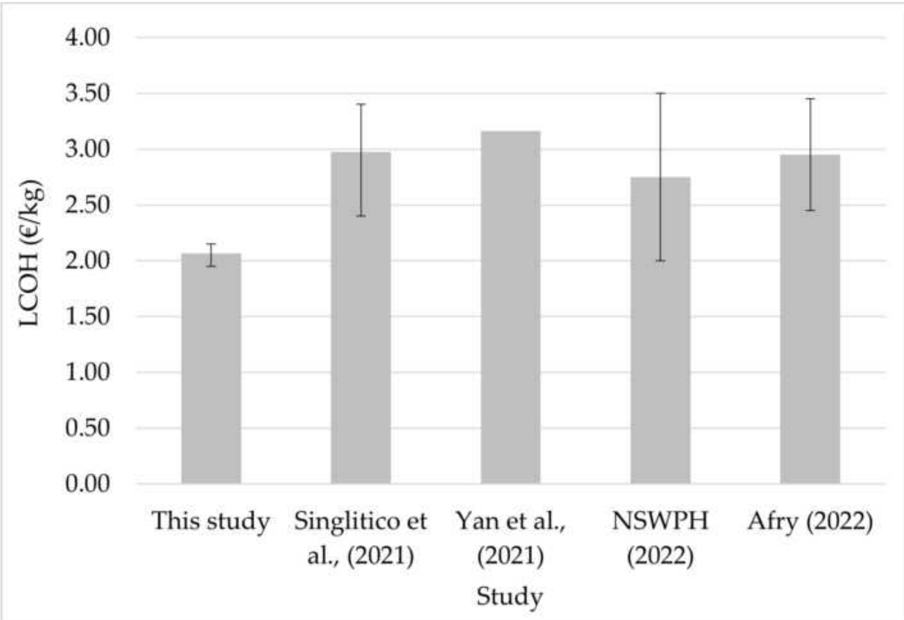

Figure 32: Comparison of LCOH (in €/kg) to values found in literature for offshore hydrogen production and transportation to shore.

2. The EHB report assumes a pipeline capacity use of 75%, whereas this study assumes it is 100%. When comparing to a 100% capacity utilisation in the previous EHB report [161], the values are more comparable: a new hydrogen pipelines is around 21 c€/kg H2 and repurposed pipelines are around 9 c€/kg H2.

The share of network costs in the LCOH for the electricity grid scenarios varies between 0.53 to 0.71 €/kg H2. Although this is difficult to compare, a comparison of the network investment costs can be made to the recent study by Jansen et al. [78]. Here, investment costs of 20 - 30 B€are expected for the transmission infrastructure of a 30 GW NS electricity grid hub, connecting all countries. Extrapolating this to this project (103 GW), this would be around 60 - 90 GW. The costs in this report are slightly higher, around 87 - 116 B€. However, when applying the LCF to the results with spatial complexity, the values vary between 65 - 82 B€, similar to [78]. This suggests that the cost values found in this study are a good estimation.

6.1.2 Spatial complexity

The *E* scenario is the cheapest scenario out of all scenarios. However, the feasibility of this network is called into question, as the resulting network has a very large length and spatial footprint as seen in Figure 33 below. The resulting network intersect multiple high-cost spatial uses at multiple points, such as the large ecological area (Doggers Bank) shown in the figure. Furthermore, relatively low capacity and long distance connections such as between BE and Scotland are unlikely to be realised as they are not feasible (see further discussion below). A real similar network would incur greater losses as well, as the individual edges have greater lengths, which increase the electrical losses [150]. However, this is not shown in this study, as a singular energy loss value is used for all distances.

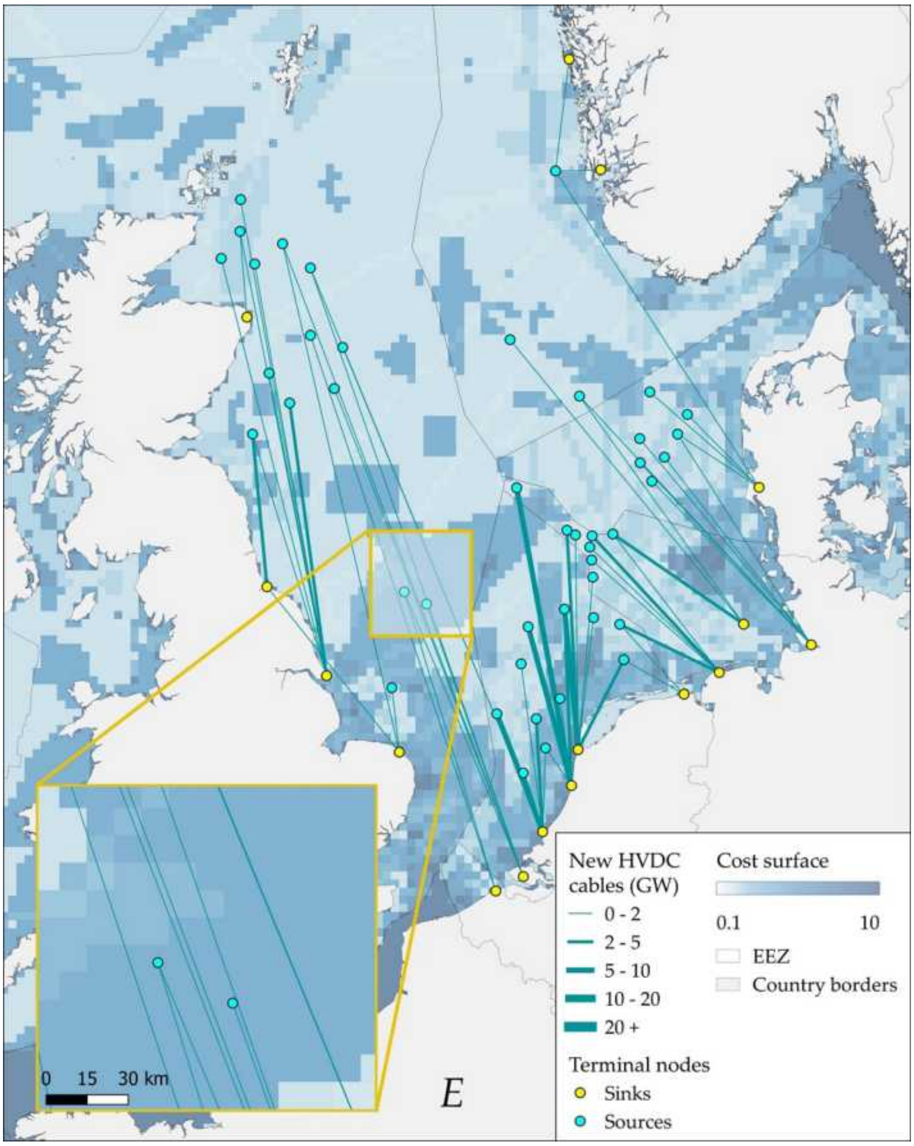

Figure 33: Electricity grid (scenario E), intersecting multiple high-cost areas in the cost surface.

The capacity-length increase from a greenfield to spatial uses approach is similarly found in the results of Boerhout [127]. Although difficult to model, this consideration of spatial uses is very important, especially with the future increase in OWF and protected areas in the NS. Specifically, the EU Biodiversity Strategy for 2030 states that 30% of the sea must be protected and 10% of the sea must be protected from multi-use, meaning no infrastructure could be placed in it [162]. MSP can be an important tool to integrate these areas and the suggested infrastructure connections. In fact, this study is intertwined with MSP, as it uses the spatial inputs defined by NS-region countries' respective MSPs, and proposes possible infrastructure routing options, which, in turn, could be used as inputs for updating ensuing MSPs. During a recent conference by the European MSP Platform, some of the key takeaways were 1) social and environmental aspects must be taken into account, 2) it will be very challenging to integrate all the future OWF, and 3) there needs to be rapid adaption and imagination to protect biodiversity [163]. The large infrastructure networks visualised in this study complement and reinforce the key takeaways from this conference. The interaction of MSPs and network planning should play an integral role in the future planning of protected areas and OWF.

6.1.3 Reusing infrastructure

The benefit of reusing existing O&G pipelines in the NS is apparent, leading to around a 40% decrease in network costs for an interconnected hydrogen network, even though the total capacity-length increases. This reinforces the results found by Boerhout [127] for the Dutch NS. However, on a system level, this saving is very small, due to the small percentage of pipeline cost in the system cost. An unaccounted benefit (in this study) for reusing pipelines is that it is less intrusive on the surrounding environment, which is an important aspect considering the increase in protected areas [120]. The electricity scenarios do not, and likely will not benefit from a reuse potential in the NS, except through corridors. Designating wide, internationally interconnected electricity corridors which allow placing of multiple cables would be extremely beneficial for an offshore electricity grid. This would limit the routing deviations and thus decrease costs and spatial footprint of connections. Furthermore, further research could elaborate on the real cost savings of reusing corridors and preferred cable and pipeline routes which are defined in MSPs. This would lead to different network topologies and costs.

The resulting maps give ideas on the main trunklines and main reuse potential of both hydrogen and electricity. However, these routes must not be considered as final, optimal routes, but rather indications of seemingly beneficial connections for countries in the NS region, which can feed in to discussions on future infrastructure planning. A similar, more detailed approach was completed for The Crown Estate, where different interactions of offshore electricity cable set-ups with spatial uses were considered [164]. For more robust results, a Monte Carlo-type modelling approach such as by Huisman [66] could be used to identify the most used corridors and connections. Nevertheless, for hydrogen pipelines, a few commonly made connections are:

- From the OWF in the German EEZ towards the south east, connecting to Dornum.
- Reuse of the Nybro pipeline (corridor) from the Danish OWF to Nybro.
- Reuse of the Dutch pipeline corridors, going from west to east.

Interestingly, these connections (and specifically connections from the *HIInt* scenario) reinforce the connections which are sketched out by the EHB report seen in Figure 34:

- From the German OWF towards the south east.
- A similar connection hub in the North of the NS.
- Connections between Bacton (south east of UK) with Zeebrugge (BE) and with Den Helder (NL).
- Use of the Langeled pipeline from the coast of the UK towards the northern hub, with a new connection to the Berwick Bank OWF on the way.
- Connection of the Sørlige Nordsjø (Norwegian OWF) to the north-south backbone.

For the electricity cables, a few connections commonly seen are:

- From the OWF in the German EEZ towards the south east, connecting to Dornum.
- From the north of the UK EEZ, down to the south along the coast, reusing a possible future electricity cable corridor.

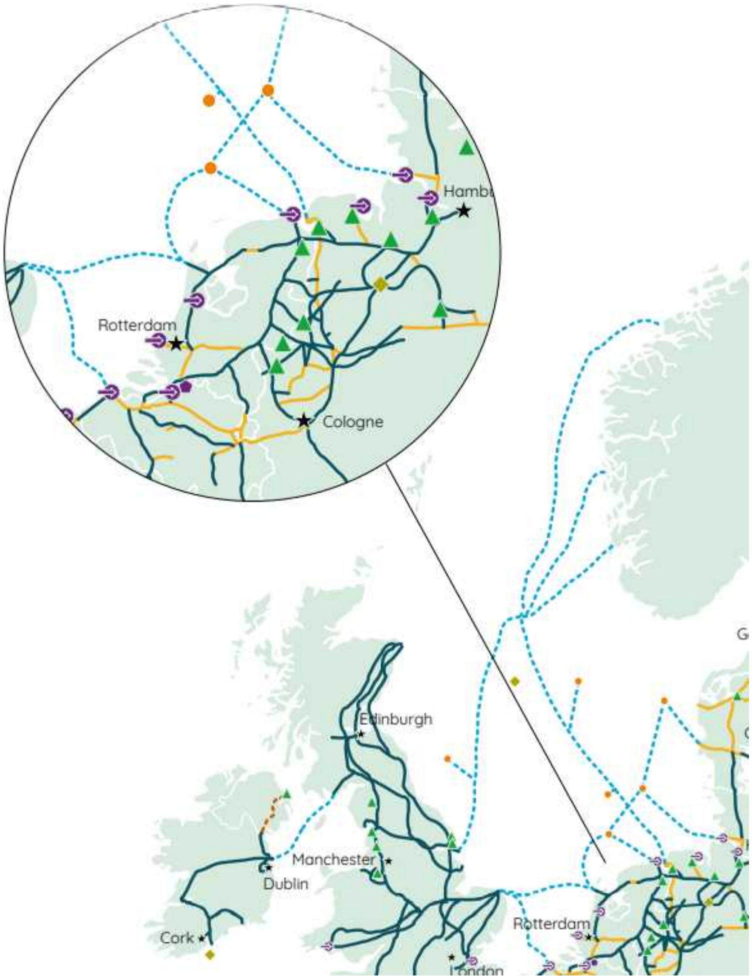

Figure 34: Outlined connections in the NS in the EHB report [59].

The sensitivity analysis shows that significant onshore connections are made when onshore connections are allwoed, and also shows which sinks may not need an offshore connection, such as Maasvlakte in NL. Although the effect on the system cost is very small (0.4%), it does decrease network costs by 22%. Additionally, the spatial footprint in the NS would be decreased significantly. On the other hand, reusing onshore pipelines may be more expensive [56, 59], which would favour a greater reuse of offshore pipelines. The same is true for onshore electricity cables, which could reduce the costs significantly in favour of offshore electricity grids. However, this might be slightly less likely, as much of the onshore grid is already overloaded in the NS-region, and is expected to worsen in the future. For example, Brown et al. [165] estimate a need of grid expansion of up to 6.5 times the current capacity to meet the needs of a fully renewable electric system. Existing onshore networks will need to be included in further research. To facilitate this, accurate onshore data on existing infrastructure locations, capacities and reuse costs should be made publicly available.

6.1.4 Interconnection between countries

For electricity grids, the costs increase with forced interconnection in comparison to forced isolation, as the cable length is significantly higher. However, it must be noted that this is purely from an investment perspective, and that the results are not a conclusive reason to avoid interconnection. In fact, interconnection between countries can provide energy security, possibilities of offshore trading, and grid balancing/flexibility [68, 72, 76]. These benefits are harder to quantify (besides grid balancing), and were not considered in this study. Nevertheless, the results do show that careful planning of interconnection is needed to avoid high costs. This planning includes the routing of infrastructure, but also which countries to interconnect, as well as the capacity of the interconnections. This is an interesting avenue for further research, where a range of scenarios of interconnecting different pairs or sets of countries could be done, such as a NL-DE-DK only scenario, based on the NSWPH and the Esbjerg Declaration [81, 14]. Additionally, to avoid high investment costs of additional converters, connections could be further specified to countries which use the same voltage levels for offshore wind farms and subsea cables.

Careful planning of interconnection design is needed as well to avoid the unbalanced allocation of costs to each country [72, 73]. This is exemplified in this study through a simple approach where each country must pay for the technology which takes place in its country. The results show that DK, NO and the UK countries pay disproportionate amounts of the costs, in comparison to the benefits which they receive from the interconnected network. Similarly, NO also benefits from an isolated approach, rather than an interconnected one. This is particularly interesting, as when interconnection takes place, the far-offshore Norwegian OWF are not connected to their own sinks, and rather connect to some other part of the network, suggesting that interconnection would be useful on this occasion. Yet, the costs increase when deploying an interconnected network, compared to an isolated one, as they must invest in large capacity-distance connections. This example exemplifies the limitation of the modelling (further discussed below) as well as in the approach of forcing countries to pay for the technologies within their own EEZ. However, it also sparks an interesting conversation about how interconnected network costs could be allocated between countries. Here, future policies may be useful to define that countries should pay costs which are reflected in their expected benefits e.g., by restricting the change in expected LCOH costs between countries to a certain percentage.

Interconnection is challenging to implement, increasing the time and costs of projects, as more procedural aspects need to be taken into account. For example, it took around 13 years to plan the Nord Stream pipeline, as it had to route through numerous EEZ of (non-)European countries [166]. Planning of the Nord Stream 2 pipeline also took 7 years, even though it was being constructed next to the first connection. In the NS, there are 8 different EEZ, with large parts being owned by NO and the UK (two non-EU countries). Considering this aspect of time and the 2050 decarbonisation goals, interconnections should be planned carefully and executed quickly, to reduce the time and costs of projects. It could be argued that hydrogen pipelines may be more beneficial in this sense, as the interconnection largely already exists between countries, possibly reducing the procedural aspects when compared to new interconnections. On the other hand, pipelines require full inspection and adaption on a case by case basis, before being able to transport hydrogen [167]. Future research could include this regulatory time-dimension aspect for 2050 decarbonisation when comparing interconnected hydrogen networks and electricity grids.

In this study, it is assumed that regulations exist to facilitate this interconnection. In reality, much regulatory support and harmonisation is strongly needed to facilitate interconnection on a NS-level [80, 72]. Additional hurdles are expected when considering system integration of electricity grids and hydrogen networks. In a recent NSE conference on this topic, it was made clear that there is a distinct lack of regulatory frameworks which support energy hubs or infrastructure connections between countries and sectors, on a national and EU level [168, 169]. Similar results are also seen on an international level, where the United Nations Convention on the Law of the Sea (UNCLOS) [170] does not give specific support on these aspects [171]. This suggests that rapid development of regulations is needed to support this integrated interconnection approach. The 3 GW offshore energy island in the Danish NS will be an interesting case to observe these developments, as it is planned to be operational in 2030, with international connections made in the following years.

Besides the regulatory support, challenges also face the actual planning of energy infrastructure interconnection as it is inexorably linked to the harmonization of MSP. Some harmonisation for MSPs is already done following the Espoo Convention, which requires countries to investigate the effects of near-border projects at an early stage of implementation [171, 172]. Examples of these are the alignment of OWF locations and shipping routes between NL, DE and DK (see Figure 16 and 17). More collaboration between NS-region countries on an MSP level is necessary, as was similarly concluded in the recent European MSP conference [163]. This could be done by defining wide corridors for cables and pipelines as is done by the Belgian and German MSPs. Specifically, policies should be developed where these corridors can be harmonized across countries, creating a future offshore backbone for energy transportation.

6.2 Limitations

6.2.1 Cost surface and least cost paths

Using spatial uses to create routing networks is an interesting approach to including stakeholder preferences in spatial energy modelling, as connections are created which avoid high-cost zones such as ecological areas. Similar exercises of prioritisation of spatial uses using stakeholder inputs is seen in the literature such as by Middleton et al. [173]. In a NS-context it is done by ARUP [174] for OWF in the UK, as well as during the creation of the German MSP [175]. These types of exercises must be done cautiously, as weighing values are contended and reaching a general consensus which fulfils all stakeholders needs is difficult. In reality, routing through the defined 'high societal-cost zones' may only cause modest increases in monetary costs [176]. This begs the question of which monetary cost is greater, routing around a protected area, or undertaking the extra procedures, time and costs required to route through it. This cost increase is difficult to represent and model as values vary on a case by case basis, as was found by Thoonsen [128]. In fact, Middleton et al. [173] point out that no studies had generated cost surfaces using real cost values. Further research would do well to establish some common values for installing infrastructure.

In this study, weighing values are extrapolated from the Dutch EEZ to the rest of the NS EEZs. Importantly, NS-region countries have differing views and priorities on spatial uses and infrastructure [177]. Efforts were made (see Appendix B) to reach out to the maritime authorities to provide opinions and expertise on weighing values of spatial uses. Expanding the scope proved difficult as MSP authorities were unable to fully participate in the short time period of the project. Discussions were completed (see Appendix B) with the European MSP platform [177], the Danish Maritime Authority (DMA) [178] and the Marine Management Organisation (MMO) of the UK [176]. It was found that:

1. Commenting on weighing values for spatial uses is unpractical without the collaboration of multiple ministries and stakeholders, similarly as what is done for MSP.

2. Policy documents on MSPs can offer clues and ideas on the prioritisation of spatial uses.

Although good suggestions were given on the importance of differing spatial uses, it was decided not to manually change the weighing values as not enough information was provided. Further research could solely focus on successfully collecting expert input from all countries and completing this analysis, similarly done for OWF in the NS [179], in the UK EEZ [174], and in Turkey [180]. For pipelines, the Nord Stream projects may be useful for this as examples of long connections intersecting the EEZ of multiple European countries [166]. More updated reports for the Nord Stream 2 projects were also available, but are currently removed due to the postponement of the project, following the invasion of Ukraine by Russia.

Not all spatial uses are considered in the cost surfaces. Fishing, a widespread important activity in the NS is not included as it a dynamic activity. This makes it difficult to pinpoint exact locations to it, or to apply a weighing value. An attempt of this was made by Gușatu et al. [179], where ‘intense’ fishing locations were chosen based on the density of fishing hours in certain areas. This approach could be adopted in future research. Physical changes in the sea are also left out of scope of this study, such as the bathymetry or substrate type, which also has effects on the routing and costs of infrastructure. This has been attempted onshore by Johnson and Ogden [93], who included slope in their optimisation of a hydrogen pipeline. However, as with other spatial uses, the costs associated with physical changes are difficult to capture as they vary on a case by case basis.

Reusing infrastructure can also cause extra costs due to crossings, where a pipeline or cable must cross one or the other [181]. This could be implemented by including other infrastructure in the creation of cost surfaces, or by identifying line features as barriers/corridors within cells when using LCPs [106]. On the other hand, synergies could be created, where cables and pipelines could use the same corridors, as is suggested by the German and Belgian MSP areas. Telecom cables could be included in this analysis as well, as they are also widespread in the NS [182]. Lastly, other spatial effects of installing technologies on large scale such as electrolysers are not considered, which would take up a further 2 km^2 in the NS [151], without taking the required 500m buffer zone into account [170]. It is important to include this as well if to have a holistic, MSP-like view on all spatial uses and offshore infrastructure. The resolution of the cost surface was simplified in comparison to the work by Boerhout [127] from 1 to 10 km grid cells, to ensure a moderate solution time for the candidate networks and ONL model. A higher cell count means that LCPs have to consider more cells before finding an optimal answer (see Section 3). The LCP approach could be further improved by introducing a 32-cell neighbourhood instead of 8, which decreases costs by 8% and creates a more accurate route [116, 183]. The A* algorithm can complete LCPs, more accurately as is done by Balaji and Rabiei [111]. Using this algorithm would also reduce the amounts of unexpected routing deviations created from the QGIS Least-Cost-Path algorithm, such as in the connection seen between the Norwegian OWF and sink in Figure 35. The A* algorithm could do this as it is a more targeted approach, simultaneously reducing the costs as well as the distance from its target.

Using cost surfaces and LCPs creates overestimated bends in output maps, where clear 90°turns are seen, as is seen below in Figure 35. In reality, transmission pipelines have a minimum bend radius of 1000 times the diameter of the pipeline [184, 185]. The effects of these bends on the capacity-lengths and costs were moderate, where the system LCOH decreases around 3% when dividing the interconnected electricity scenario (*EIInt*) by the LCF ($\sqrt{2}$). It is suggested that these bends are taken into account in future research by techniques such as Laplacian smoothing [186, 128] or by ArcGIS smoothening algorithms [111]. However, Antikainen [183], argues that the cost-saving effects of improving LCPs to be more accurate are small in comparison to the uncertainties of using the approach itself. An alternative method to avoid this LCP approach completely could be by using the obstacle function of the model by Heijnen et al. [129], where the optimisation solution space is limited by prohibiting the model to route through certain areas. This reaches a similar goal as the LCP approach in this study, especially for very high-cost areas (such as nature areas), as the LCP rarely route through them. This approach is seen in Heijnen et al. [187], and is currently being undertaken for hydrogen networks in the NS by Van Tongeren [188].

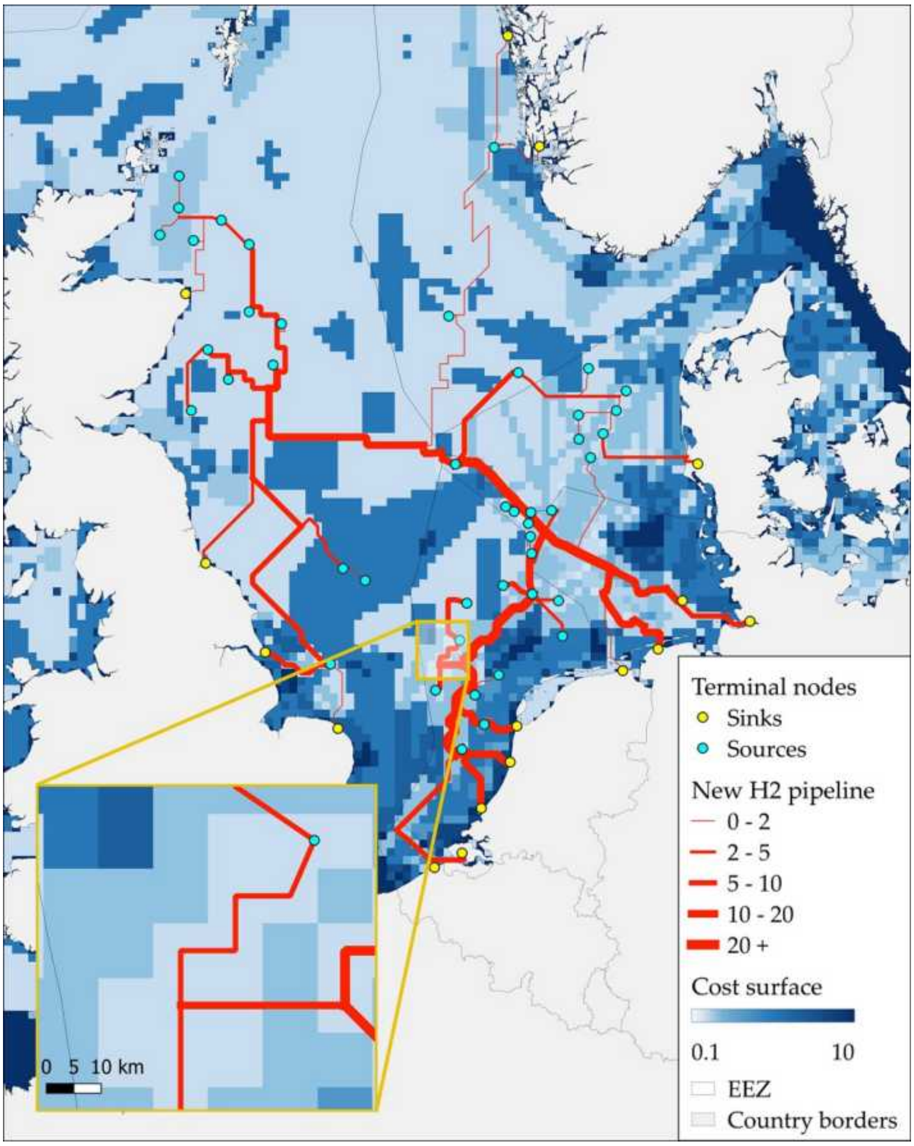

Figure 35: Overestimated 90° bends in HSpa scenario.

6.2.2 Optimal network layout

Decreasing the resolution of the cost surface also reduces the amount of node pairs for the ONL model [129], which is useful for smaller sets of data, with 10s to 100s of nodes. The number of node pairs in this project is in the thousands, causing model runs of several hours. Consequently, further research could attempt to reduce the amount of input nodes to the optimisation, such as by using the smoothing or obstacle approach defined above.

To find optimal networks, the ONL model uses an 'edge-swap' algorithm which iteratively swaps high-cost connections to a different connection while maintaining capacity, to see if a lower total network cost can be reached. This procedure does not guarantee a global minima, and could be improved by using an improved technique such as the High Valency Shuffle from Yeates et al. [131], where multiple edges are swapped at once, reaching more optimal solutions.

The ONL requires that total supply = total demand for all nodes in the optimisation, which leads to unrealistic long-distance, low capacity connections between Scotland and BE/NL in Figure 33. These type of connections are unlikely to materialise in reality, as they would more likely connect to a closer point. Here, a similar approach as by Heijnen et al. [187] could be used, where the expected worth of pipeline connections is calculated. The optimised network is a maximisation of that worth, thus low-worth connections are deleted. A similar approach is used by Huisman [66] where connections between sources and sinks are only made if it leads to a positive net present value (NPV) for that connection. These approaches could reduce overinvestments in capacity, and possibly result in networks with more realistic topology, without overly increasing the model complexity and running time.

6.2.3 Existing infrastructure

Editing was required to the existing pipelines dataset from EMODnet due to the impreciseness of the data. Automated QGIS tools (Snap to grid, Simplify, Delete duplicate geometries, Explode) were used to create a complete network from the dataset (Figure 36), which is required as an input to the ONL model in the methodology of this study. Automation was used as the dataset is very large (thousands of pipelines), yet means that there might be faulty or lacking pipeline connections. Efforts were made to prevent this through additional manual editing of the data, but there is no guarantee that the attempts were exhaustive. For further research purposes, EMODnet and NS-region countries should work together to improve the datasets on offshore infrastructure.

Edits were also made to add possible connection points from the sources to the existing infrastructure. This was done by creating nodes along the O&G infrastructure and running LCPs between these nodes and the sources. This allowed identification of points along the existing infrastructure were it is beneficial for a connection. After identification, minutely-angled artificial inflection points were created in the infrastructure. This allows the candidate networks model to identify these inflection points as a new edge segment, which is necessary to create the correct node pairs as inputs for the ONL. However, this manual approach means that not all connection points are inserted in an optimal location, and leads to differences in the visual results, such as between the *EIInt* and *EIIso* scenarios. Here, *EIInt* uses the existing infrastructure node data whereas the *EIIso* uses the LCP routing data, yet both follow the same route and have the same cost savings of doing so. Additionally, the real location of these connection points could be dependant on bathymetry, proximity to existing offshore O&G platforms or type/quality of pipeline. Future research could simplify and autonomise the approach of creating connecting points from sources to existing infrastructure, as well as include other criteria such as the ones mentioned above.

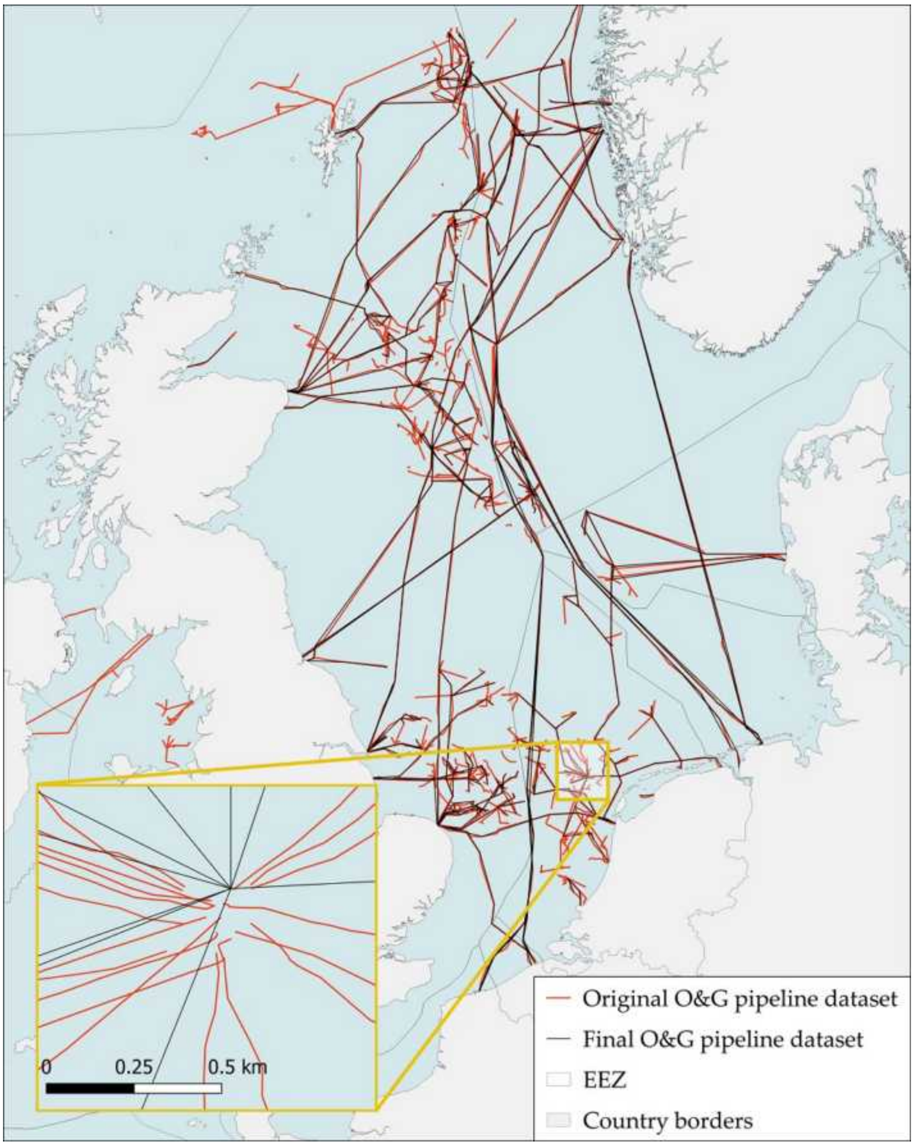

Figure 36: Example of the changes between starting and final dataset of offshore O&G pipelines.

The HHV of hydrogen was used to convert the pipeline diameter to capacity and the compressor powers required leading to a slightly lower cost (15% compared to using lower heating value (LHV), as hydrogen has a higher energy content per mass. However, as both components have very low costs, the effects on the total LCOH are negligible. Additionally, pipelines may have a higher diameter to capacity conversion if they are able to transport at a faster flow rate (e.g. 50 m/s) [136], which would lead to reduction of needed capacity in pipelines. It is likely that this would decrese the total capacity-lengths and costs of the hydrogen network in the NS, but further research is required to confirm this.

For O&G pipelines, it is optimistically assumed they will all be possible to reuse starting from 2040, which might not be the case, as currently only DK has pledged to stop O&G production in the NS [189]. Additionally, existing pipelines may be used for the transportation of CCS. For the electrical infrastructure, it is assumed that all the planned and search areas reported by 4C Offshore will be realised, which is highly likely to differ in the future. It is uncertain whether corridors can be reused as well. For example, in the UK, there is currently no regulatory backing for multi-use of electrical infrastructure corridors [176]. Further research should concentrate on detailing when and which infrastructure (corridors) could be reused for the purposes of bringing energy to shore. Additionally, regulatory and policy support are required to promote this multi-use of infrastructure corridors.

6.2.4 System boundaries and scenarios

As the model is static, it is assumed that all infrastructure is built at once. This will not happen in reality, as construction of large projects of pipelines alone take 2-3 years to realise [166], without taking into account the OWF and other infrastructure. A modular build out such as suggested by NSWPH [160] will be more probable, which provides and answers a more natural growth in supply and demand. This growth is not constant either, with fluctuations on the scale of seconds to years. Fluctuations also vary spatially across the NS, as there are slight variations in wind speed [190]. To account for this, maximum supply and demand values were chosen, i.e., the pipeline and cable infrastructure were designed to be able to transport the maximum rated power output of the OWF. Although this ensures no curtailment, it also might lead to overinvestments in capacity. Further research could find more applicable infrastructure capacities by using more detailed supply (through wind speeds) and demand (specific industrial cluster processes), to resize the infrastructure to more appropriate capacities. In fact, this could further benefit the case for offshore hydrogen, as electrolyser could be downsized (sometimes running on overcapacity [27]) and pipeline capacities could decrease (while using their linepacking ability for short term storage [191]) leading to decreases in cost.

The approach to supply and demand in this study is to normalise the demand of hydrogen to the supply, on the basis that onshore demand will always be greater than offshore supply. This is useful, as it reduces the need of finding exact demand data, which is highly uncertain due to the diverse and contested uses of hydrogen [35, 192]. The approach places more importance on the spatial difference of hydrogen demand, which is easier to define compared to exact values due to the locations of existing industrial hubs and population densities [153]. However, this approach disregards the spatio-temporal variability of hydrogen supply and demand, where certain regions and countries might develop their offshore hydrogen supply and demand at different time horizons. For example, in NL, Gasunie [193] have planned a hydrogen backbone for 2030, which is contrasted with NO, where plans are not nearly as ambitious or developed [59].

To account for the spatio-temporal dependency of infrastructure investments and supply and demand patterns, it is possible to use a step-wise approach (e.g. 2030, 2040 and 2050), where the model inputs can be set to the expected supply and demand each year. Additionally, it would be possible to use the infrastructure built in 2030 as an input for 2040, and so forth. To go even further, the model could take into account future increases in demand, and invest in over-capacitated infrastructure connections to account for the expected demand. Such an approach is done by Middleton et al. [115]. However, this becomes a very complex MILP optimisation, which usually take very long to find an optimal solution [194]. Even then, the optimal answer is highly unlikely to be the real network, considering the future uncertainties of hydrogen and network development [195]. These uncertainties can be taken into account by following a Monte-Carlo type approach for supply and demand, such as such as by [66]. However, due to the optimisation running time, it was not practical to run a large number of simulations in this project.

Manually choosing terminal nodes (sources and sinks) also limits the scope of outputs to the model. By 2040, other OWF areas will be defined, and some speculated OWF may be cancelled. Furthermore, other offshore energy components such as floating solar (e.g. Oceans of Energy [196], wave, and tidal energy may also become a significant part of an offshore energy system. Energy islands were also left out of scope when determining the source nodes. Future research should attempt to tackle this as they are likely to play a key role in interconnection in the NS, supporting a hub-and-spoke network design. Additionally, it would significantly change the routing and costs, as more pre-defined pathways would be chosen. Determining the sinks for offshore connections could be improved by finding the onshore transport capacities, as mentioned previously. Lastly, the scope excluded offshore storage in salt caverns as well as offshore O&G platforms. Knowing that hydrogen storage in salt cavern in the NS is a very attractive option (see [32]) it would be beneficial to include this in the optimisation, creating connections to these areas. Similarly, the reuse potential of offshore O&G platforms for electrolysers or converters could also be considered, providing synergies and decreasing costs.

7 Conclusions and recommendations

7.1 Conclusions

The aim of this thesis project was to design and compare hydrogen networks with electricity grids in the North Sea (NS), taking into account spatial complexities, the potentials of reusing existing infrastructure and the effects of interconnection. Such networks will be vital in the coming years to transport the vast amounts of future offshore wind energy to shore, aiding NS-region countries in reaching their decarbonisation goals by 2050. To fulfil the aims of this thesis, a number of research questions are answered.

1. *How do spatial complexities and the reuse of existing infrastructures affect energy infrastructure routing and network costs when compared to a greenfield approach?*

Spatial complexities increase the capacity-length of a network by around 50% to 90%, when compared to a greenfield approach. This is because the network must route around defined high cost spatial uses, which increases the length. This also leads to cost increases in comparison to the greenfield approach. These trends are seen both for the hydrogen networks and electricity grids. Reusing existing infrastructure increases the capacity-length of the networks, compared to the scenarios with spatial uses. However, the cost decreases due to the potential of reusing infrastructure at lower costs than new investing in infrastructure.

- For the hydrogen network scenarios, costs for reusing are 40% less than the scenario with spatial uses, and even 10% cheaper than the greenfield approach, due to 84% of the network reusing the existing oil & gas (O&G) pipelines in the NS. Of the reused pipelines, 68% require upgrades in capacity.
- For the electricity grid scenarios, the costs are still higher when reusing infrastructure corridors compared to the greenfield approach, as only small savings are made when reusing corridors. Compared to the scenario with spatial uses, the costs are around 5% cheaper, while 60% of the network is created using infrastructure corridors.

2. *How does the size and investment costs of the network vary when countries are interconnected via their offshore energy networks, compared to an isolated approach?*

The network capacity-length decreases in size when isolated compared to interconnected, with a 28% decrease for the hydrogen networks, and a 37% decrease for the electricity grids. For the electricity grid, the cost is 16% cheaper for an isolated approach. For the hydrogen network, the costs do not show a significant decrease from an interconnected to isolated scenario. The reason for this is that the interconnected scenario increasingly benefits from reusing existing infrastructure at lower costs, due to the moderate degree of O&G network interconnection which already exists in the NS. So, although the capacity-lengths are higher while interconnected, the costs remain similar. Importantly, this study does not suggest that interconnection of electricity grids is not beneficial, but shows that interconnection should be planned carefully to avoid sunk costs, overcapacitated connections and asymmetrical investment costs between countries.

3. *How do the spatial and economic properties change between an interconnected hydrogen network compared with an interconnected electricity grid?*

Hydrogen networks on the whole lead to greater connections of capacity-lengths due to the cost-benefits of increasing capacity. Electricity grids lead to more star-like networks as they do not share such a benefit. In terms of routing, hydrogen networks prefer pathways which follow the existing O&G network as well as areas designated in marine/maritime spatial plans (MSP)s for placing pipelines. Electricity cables also follow areas defined in MSPs, as well as the possible future corridors of electricity cables. Looking at the network investment costs only, hydrogen pipeline networks are cheaper (ranging between 14 - 21 B€) than electricity grids (ranging from 87 to 116 B€). Crucially, these costs cannot be considered separately, as they are part of a larger hydrogen production system. The system LCOH does not vary significantly across all scenarios, suggesting that off- and onshore hydrogen production and transportation are competitive.

- The main reason for this flatness is that savings from hydrogen networks instead of electricity grids are counteracted with the high costs of offshore electrolyser platforms.
- The LCOH varies in all scenarios from 1.95 to 2.15 €/kg of hydrogen in 2040.
- When considering sensitivities, offshore and onshore hydrogen production still remain competitive with each other.

And finally, this can lead us to answer the main research question.

Considering spatial complexities and uncertainties, what are the most suitable energy network configurations for producing hydrogen in the North Sea region in 2040?

Large connections will be seen between the Netherlands, Germany and possibly the United Kingdom (UK), as they have the largest expected hydrogen demand. Reusing existing O&G pipelines infrastructure (corridors) such as the Dutch pipelines will lead to significant cost savings for hydrogen networks. For electricity grids, direct corridors such as the northeast to southwest defined area in Germany will be useful to decrease the capacity-lengths and thus costs of electricity cables. The most suitable network configurations will include both hydrogen pipelines and electricity networks, as they are cost competitive. Other deciding factors than the LCOH should be used when deciding which infrastructure should be installed at specific locations.

7.2 Recommendations

Taking into account the literature, the discussion and the conclusions, a number of recommendations can provided.

Short term, national level:

- In the Netherlands, Gasunie should expand their the scope of their recent backbone plans to offshore. Significant cost savings could be made by reusing the pipelines in the Dutch NS. The Netherlands could become a leader in this field, providing valuable information to feed policies and regulations in other NS-region countries.

Medium term, European level:

- Knowing electricity grids and hydrogen networks are cost competitive, promote integrated hub-and-spoke energy islands between the Netherlands and Germany due to high future hydrogen demands. This simultaneously provides benefits of both systems such as flexibility, cost savings and lower onshore network investments.
- This promotion should be done through regulatory support (which is currently lacking) and careful subsidisation of energy islands.

Long term, North Sea level:

- Investigate the interaction of spatial complexities, infrastructure planning and actual installation costs. Doing this will provide a better understanding of how routing and costs increase when considering NS spatial uses.
- Using this knowledge, define broad interconnection corridors for future infrastructures between countries. This can be done by using MSP (on an European or global) level, such as the infrastructure corridors defined in the Belgian and German MSPs.

Modelling and further research:

- Include the dynamic spatio-temporal aspects of hydrogen supply and demand in NS infrastructure modelling, which can reduce the amount of overinvestments in capacity. In tandem, use a step-wise approach to modelling, where inputs such as available O&G infrastructure, offshore wind farms and other energy sources vary year by year as they become available.
- Ensure future modelling only makes offshore connections to onshore sinks if it is a benefit by including onshore transmission connections. This will reduce the amount of sunk cost in offshore investments, leading to more realistic and cost-effective network topologies in the NS.

Using these recommendations, it will be possible to develop and plan a targeted future hydrogen production and transportation system in the North Sea in order to reach 2050 decarbonisation goals at low costs.

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Appendix

A Models

The cost surface model and candidate networks model are used in PyQgis. The scripts for both models are provided and stored by the University.

The ONL network model from Heijnen et al., [129] was provided by the author, and was downloaded on request from a TU Delft repository. Specifically, the model was adapted to suit the needs of this work.

- **Module: *user interface*** - Addition of a new binary variable '*routecosts*', set to True or False.
- **Module: *general procedures*** - Variable *routecosts* added to following submodules: *existing connections from file, routing network, draw routing, complete routing length graph, euclidean length graph, add routing path.*
  - Submodule: *routing network* - weight between nodes set as route costs if *routecosts* = True.
  - Submodule: *routing length graph* - weight between edges set as Dijkstra path length.
  - NEW submodule: *total real cost* - calculates cost based on length of edges, not the weight defined, in order to get a distance based cost. Similar to total cost submodule, but defined graph as an euclidean weighted graph first.
- **Module: *step 3 initial topology*** - Variable *routecosts* added to following submodules: *initial network, min length steiner tree, ming length steiner tree with existing, steiner tree 2.*
- **Module: *step 4 minimum cost spanning tree*** - Variable *routecosts* added to following submodules: *min cost spanning tree, next delta tree.*
- **NEW module: *step 7 qgis*** - final result (NetworkX graph) is converted to a pandas dataframe. Node attributes from the final results are also converted to a different dataframe. Both dataframes are merged based on the source and target values. These intermediate results are exported to csv. Using the the x, y, x1 and y1 values (two points in space), linestrings are created. Using these sets of linestrings, a geodataframe is created, which is then exported as a shapefile.

To sense-check the new binary variable in the model, it was analysed on small sample data, as shown in Figure 37. As the figure shows, the *routecosts* variable was added correctly.

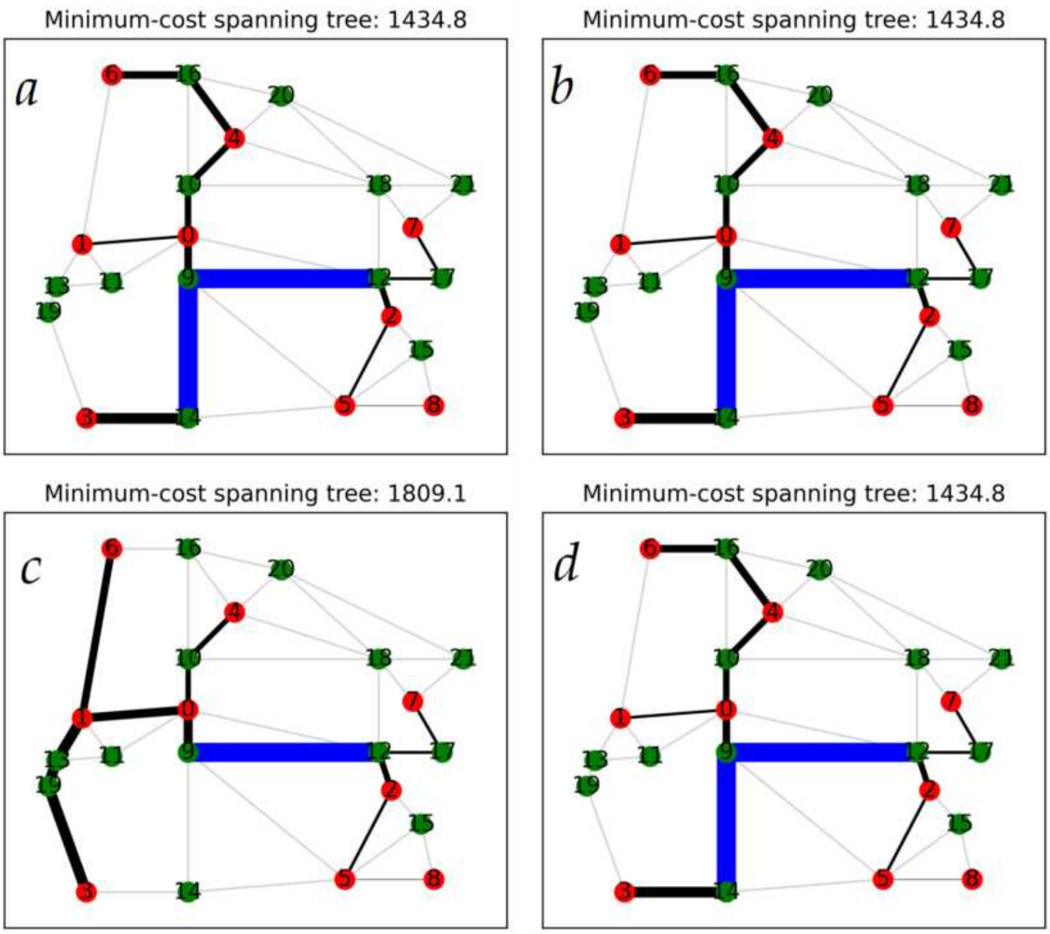


Figure 37: ONL sense-check, using the new routecosts variable. In a, the model is ran with routecosts = True, but with the edge weights are set as euclidean distance. In b, the model is ran again with no weights (meaning the euclidean distance is used), showing the same result. In c, routecosts = True and a very high weight is applied to the node connection of 3-14, resulting in a change in the network. In d, routecost = False, resulting in the euclidean distances being used again and the result being the same as a and b.

B Data collection

B.1 One-pager

Figure 38 below shows the one-pager that was sent to the MSP authorities to attempt to collect inputs for the weighing values of spatial uses.

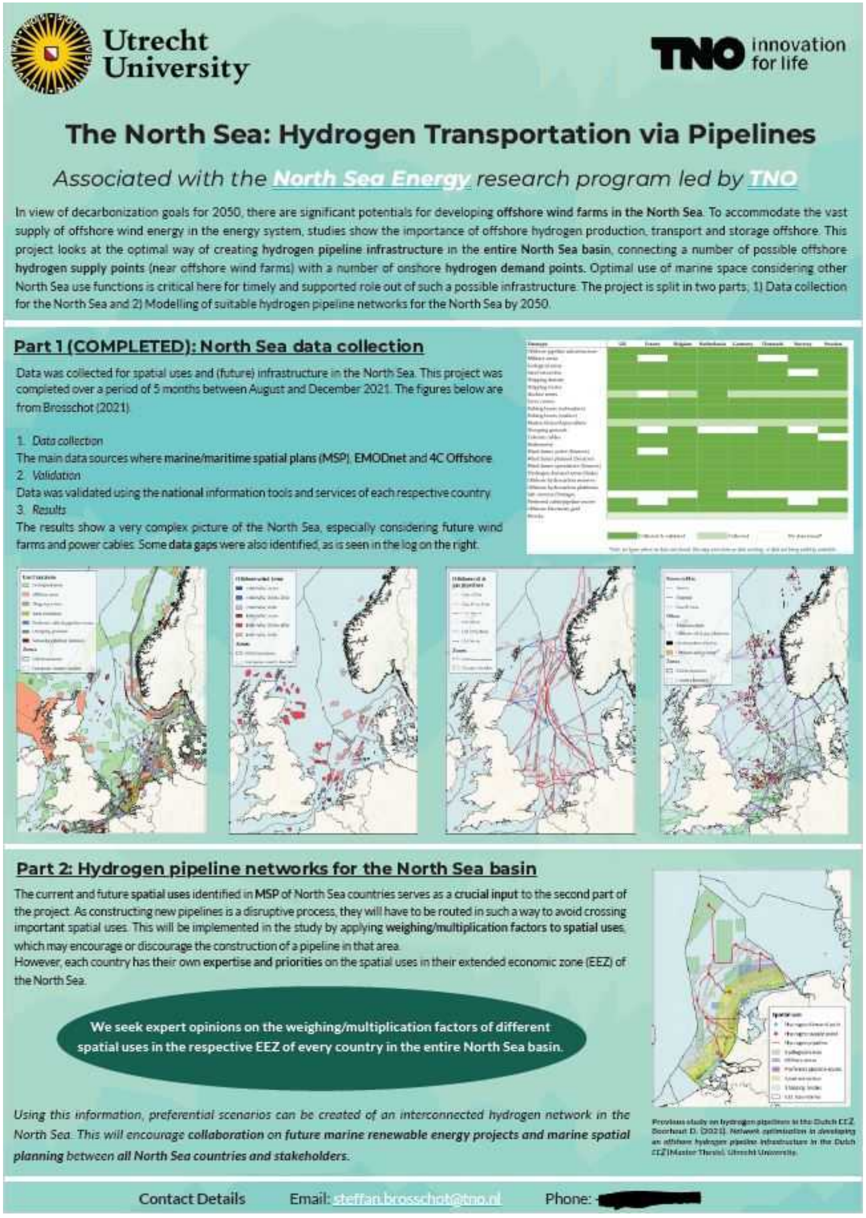


Figure 38: One-pager which was sent to marine authorities of NS-region countries.

B.2 Interviews

Meeting 10-5-22 [176] Carl Jönsson (UK – MMO), Steffan Brosschot.

- Crown Estate - Owners of the subsea in the English marine area. Have a data portal with all available data.
- Marine spatial plans (led by policy documents) tell a lot about the compatibility of certain areas with each other.
- Defence (military) areas are missing some data. See English Marine Plans – page 252 for defence area.
- General comment – MMO normally look at a wider view, including community issues (of landing points), as well as tourism and others. The MMO try to expand the scope to a societal view.
- On the weighing values:
  - The UK do not prioritise areas. They take a more holistic view of things which are compatible or not compatible. Spatial uses are thought more in terms of soft and hard uses, where soft means it is more compatible.
  - Ecology – seems to be quite high in current numbers. Is important, but has been in previous modelling considered a soft use.
  - Sand & aggregate extraction – considered a hard use, not very compatible with laying infrastructure and should be higher.
  - Military – no comments.
  - Reusing corridors – Are heavily protected. Not easily reused. However, government are looking to increase the co-location and co-existence of activities. So reusing corridors could very likely be an option in the future.

Meeting 8-6-22 [177, 178] Jesper Jakobsen (Denmark – DMA), Patrycja Enet (European MSP Platform, MSP Assistance Mechanism North Sea Focal Point), Steffan Brosschot.

- Danger and exercise areas are available in the marine spatial plan now.
- It is challenging to provide specific comments on the weighing values
  - Need all agencies to be involved
  - Too early to provide details and comments, because the agencies do not know how much of an effect such infrastructure installations would have on the agencies. More information is needed on how the network would affect the spatial uses.

- Executive orders in the MSP as well as the MSP zones distribution can provide more information on the prioritisation of areas.
  - Page 33 of the explanatory notes.
  - `https://havplan.dk/en/page/info`

B.3 Techno-economic data

Figure 39 below displays the conversion from inch to capacity used in this study [136]. The lower value of 20 m/s was used (red line).

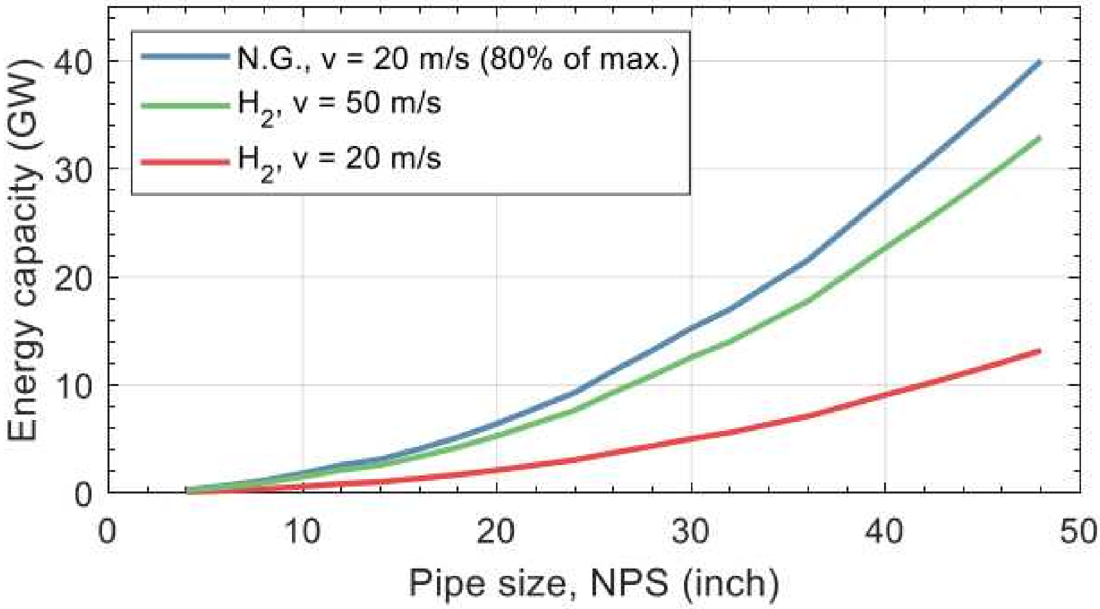


Figure 39: Pipeline inch to capacity conversion [136].

Figure 40 shows the relationship between cable capacity and cost, showing a linear relationship. This is why the cost-capacity coefficient of cables is given a value of 1 in the methodology of the ONL model.

Figure 41 below shows the average pipeline cost comparison of the dataset source used in this study with the Danish Energy Agency [151], for the same range of capacities. The values are very similar.

Figure 42 shows the cost differences between the electrical infrastructure cost values used in this study, and the cost values defined by Härtel et al., [154]. Specifically, the values are compared to the average parameter set that is defined, as well as the dataset costs including the average error. The graph shows that the values are roughly similar to the datasets.

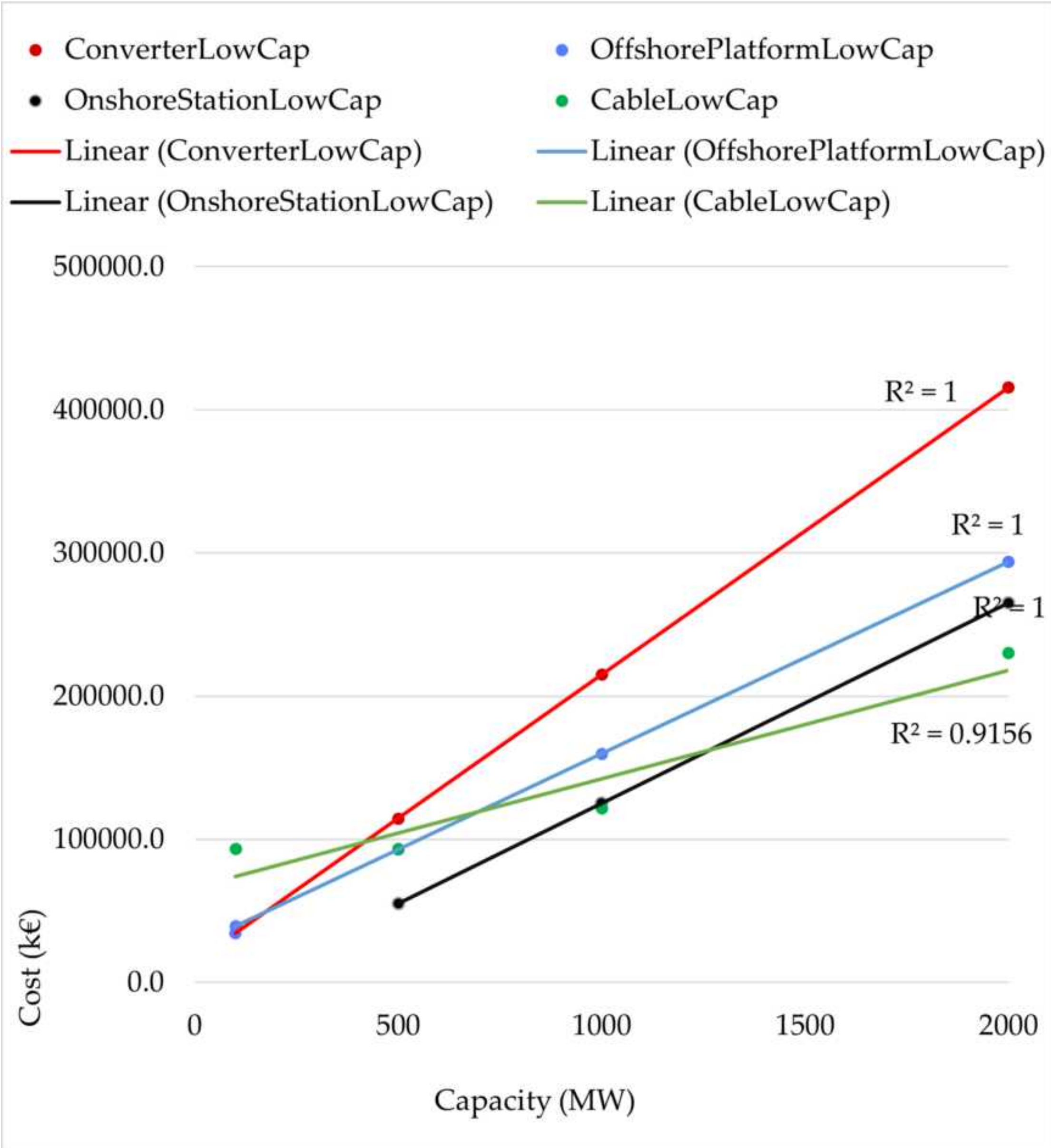


Figure 40: Relationship between cable capacity and costs. Derived from internal TNO data on existing projects [21].

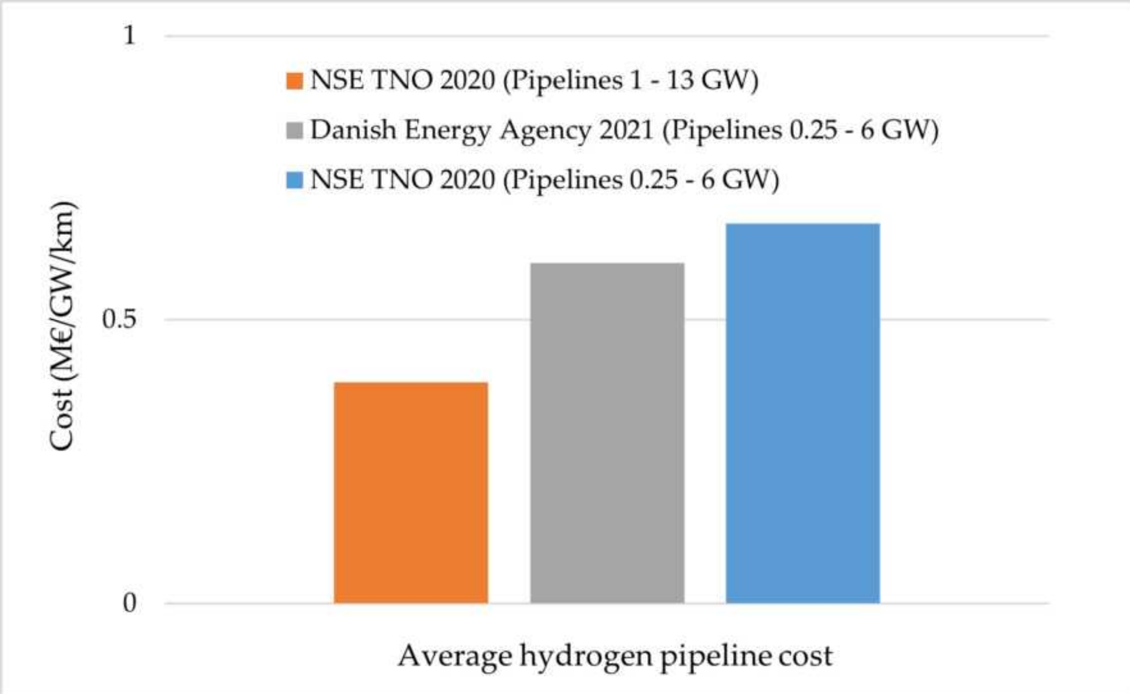


Figure 41: Hydrogen pipeline cost comparison from NSE TNO data to the Danish Energy Agency (in M€/GW/km).

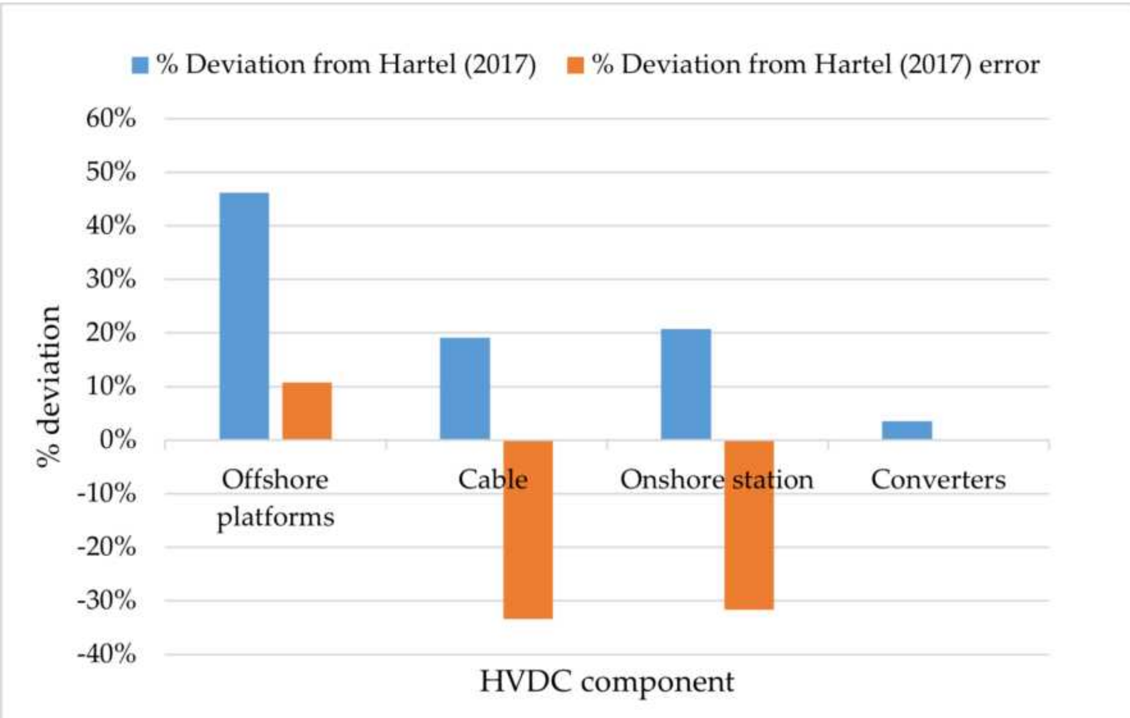


Figure 42: HVDC cable cost comparison. % Deviation of NSE TNO data from Härtel et al., [154]. The average dataset is taken as well as the change in dataset when considering the average error of components, as calculated in the study.

B.4 Hydrogen demand

As the comparison in Table 14 below shows, the values in the compared studies are quite similar to the ones assumed for UK, Norway, Belgium and Denmark in this study. However, for Germany and the Netherlands, the roles have been reversed. This is due to demand only being taken from the coastal areas of all countries for this study, meaning much of the inland demand in Germany is not taken into account (see Figure 43). It is assumed here that the inland hydrogen demand is provided from elsewhere.

Table 14: Comparison of spatial differences in hydrogen demand per country from studies to this study. Values in italic are estimated based on the FCOH current use.

Country	Source Fuel Cells & Hydrogen Observatory [197]	EHB 2050 [161]	TYNDP GA 2050 [198]	TYNDP DE 2050 [198]	This study [153]
Belgium	10%	9%	10%	8%	2%
Denmark	1%	2%	2%	3%	2%
Germany	41%	46%	57%	53%	21%
Netherlands	31%	13%	14%	19%	61%
Norway	5%	5%	5%	5%	1%
UK	12%	24%	12%	12%	13%

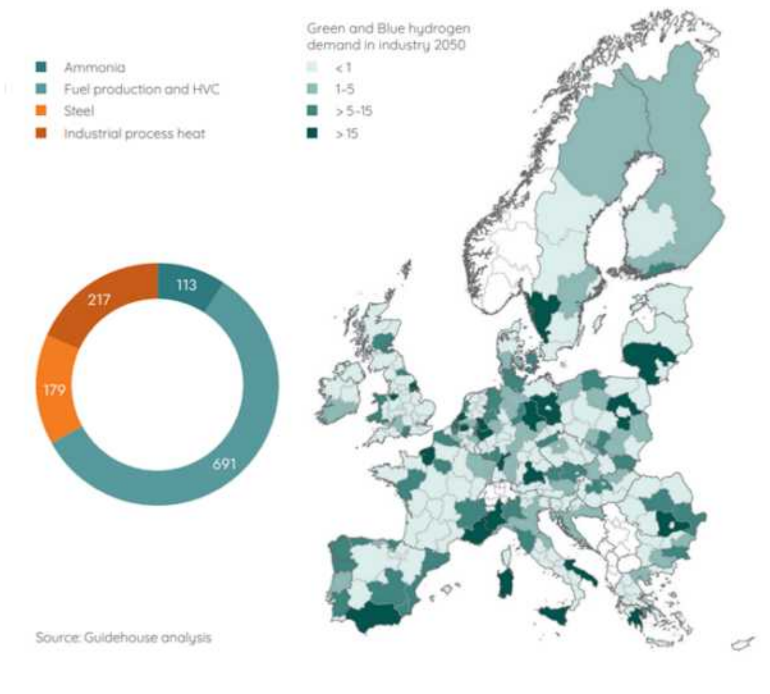


Figure 43: Hydrogen demand in 2050 per NUTS-2 level in the EHB report [161].

B.5 Spatial uses

Table 15: Table of spatial uses used in study with sources. Data gathered during internship project for TNO.

Data	Countries	Last edit	Links
Offshore oil & gas pipelines	All	29-11-2021	TNO internal (NSE Atlas)
Ecology	All	30-11-2021	TNO internal (NSE Atlas) https://kartkatalog.miljodirektoratet.no/Dataset/Details/702
Sand extraction	All (except N)	2-12-2021	TNO internal (NSE Atlas) https://www.emodnet-humanactivities.eu/view-data.php https://overpass-turbo.eu/ https://environment.data.gov.uk/DefraDataDownload/?mapService=MMO/MarineLicencesAndApplicationsPolygon&Mode=spatial https://www.bsh.de/EN/TOPICS/Offshore/Maritime_spatial_planning/maritime_spatial_planning_node.html
Military areas	All (except D, F)	1-5-2022	TNO internal (NSE Atlas) https://www.emodnet-humanactivities.eu/view-data.php https://overpass-turbo.eu/ https://www.bsh.de/EN/TOPICS/Offshore/Maritime_spatial_planning/maritime_spatial_planning_node.html https://marine.gov.scot/maps/nmpi https://kartkatalog.geonorge.no/
Shipping routes	All	30-11-2021	TNO internal (NSE Atlas) https://www.emodnet-humanactivities.eu/view-data.php https://overpass-turbo.eu/ https://environment.data.gov.uk/DefraDataDownload/?mapService=MMO/HighDensityNavigationRoutes&Mode=spatial https://www.bsh.de/EN/TOPICS/Offshore/Maritime_spatial_planning/maritime_spatial_planning_node.html https://datahub.admiralty.co.uk/portal/home/index.html https://environment.data.gov.uk/DefraDataDownload/?mapService=MMO/ImportantNavigationRoutesPS2&Mode=spatial
Offshore electricity grid	All	1-5-2022	TNO internal (NSE Atlas) https://www.emodnet-humanactivities.eu/view-data.php https://www.4coffshore.com/windfarms/
Preferred cable and pipeline routes	All (except F, N)	24-11-2021	https://www.emodnet-humanactivities.eu/view-data.php https://environment.data.gov.uk/DefraDataDownload/?mapService=MMO/MarineLicencesAndApplicationsPolygon&Mode=spatial https://www.bsh.de/EN/TOPICS/Offshore/Maritime_spatial_planning/maritime_spatial_planning_node.html https://maps.rijkswaterstaat.nl/dataregister/srv/eng/catalog.search#/metadata/a41aee23-b7f6-4591-b9dc-5b51b0730a44 https://www.havochvatten.se/planering-forvaltning-och-samverkan/havsplanering/havsplaner/ladda-ned.html
Offshore wind farms (Sources)	All	1-5-2022	TNO internal (NSE Atlas) https://www.emodnet-humanactivities.eu/view-data.php https://marine.gov.scot/maps/nmpi https://www.4coffshore.com/windfarms/ https://www.netzentwicklungsplan.de/de https://ens.dk/service/statistik-data-noegletal-og-kort/download-gis-filer https://ens.dk/ansvarsomraader/vindenergi/fakta-om-vindenergi https://www.nve.no/energi/energisystem/vindkraft/vindkraft-til-havs/
Onshore pipeline docking points (Sinks)	All	1-5-2022	

C Other results

C.1 Cost surfaces

Figure 44 and 45 show the cost surfaces used for scenarios.

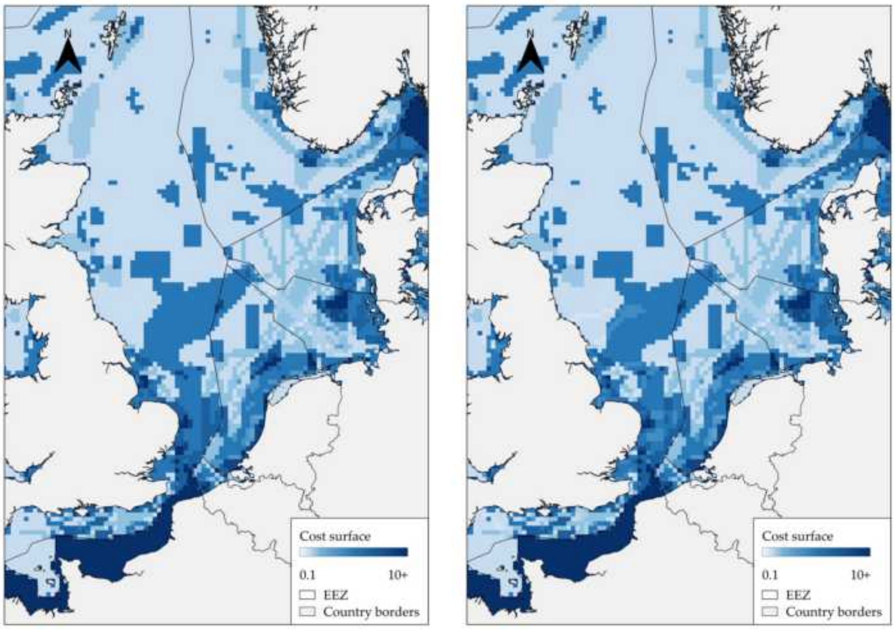


Figure 44: Cost surfaces for scenarios HSpa (left) and ESpa (right).

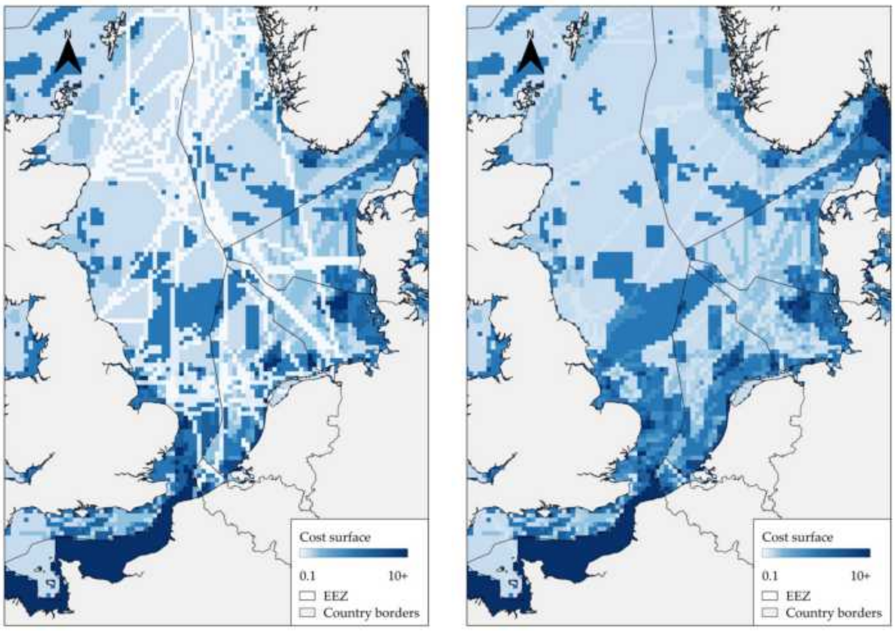


Figure 45: Cost surfaces for scenarios HIInt and HIIso (left) and EIInt and EIIso (right).

C.2 Optimal networks

Figure 46 below shows the results of the integrated scenarios.

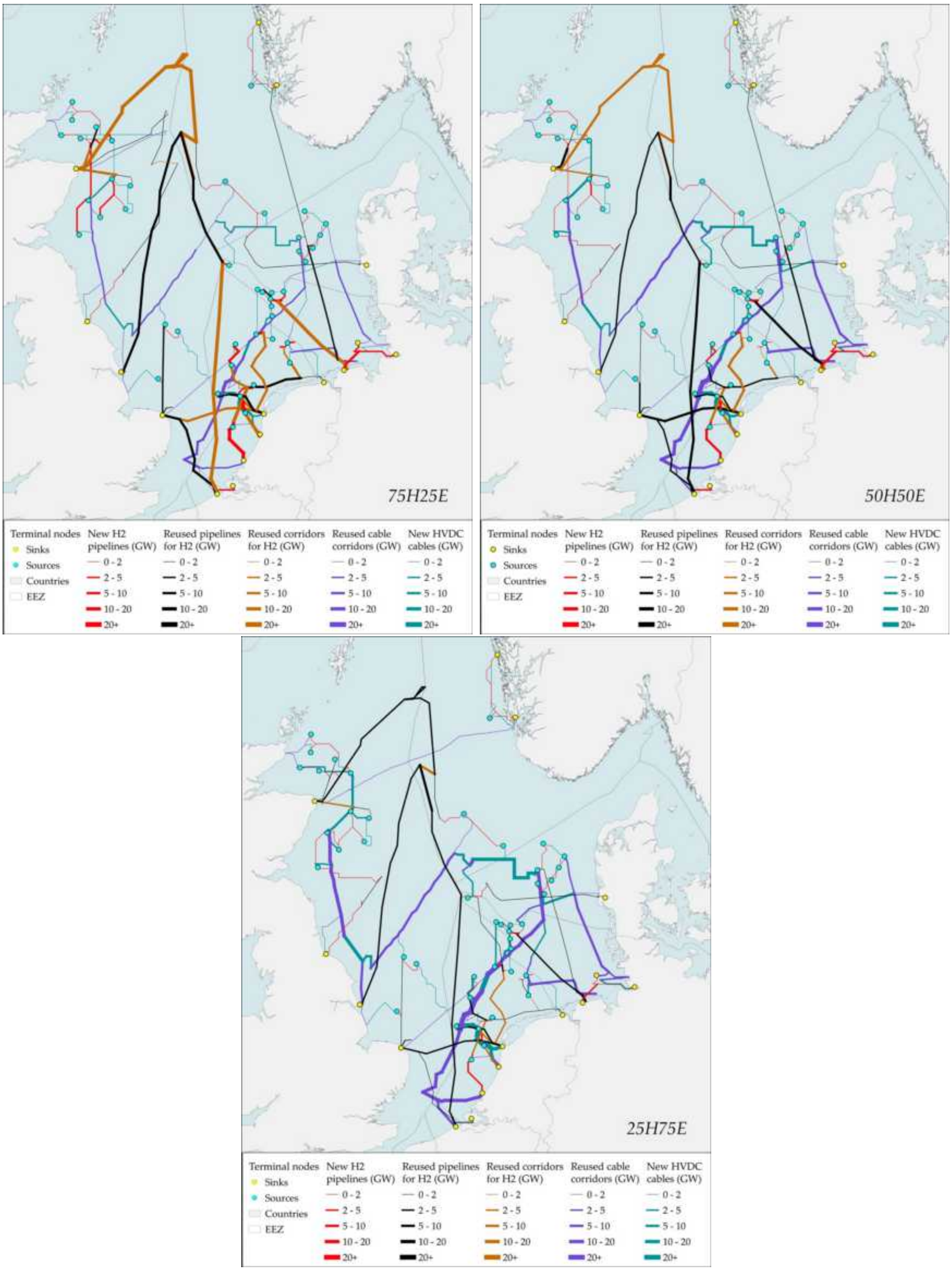


Figure 46: Resulting networks from the integrated scenarios (scenario name is stated on each figure).

C.3 Total infrastructure capacity lengths

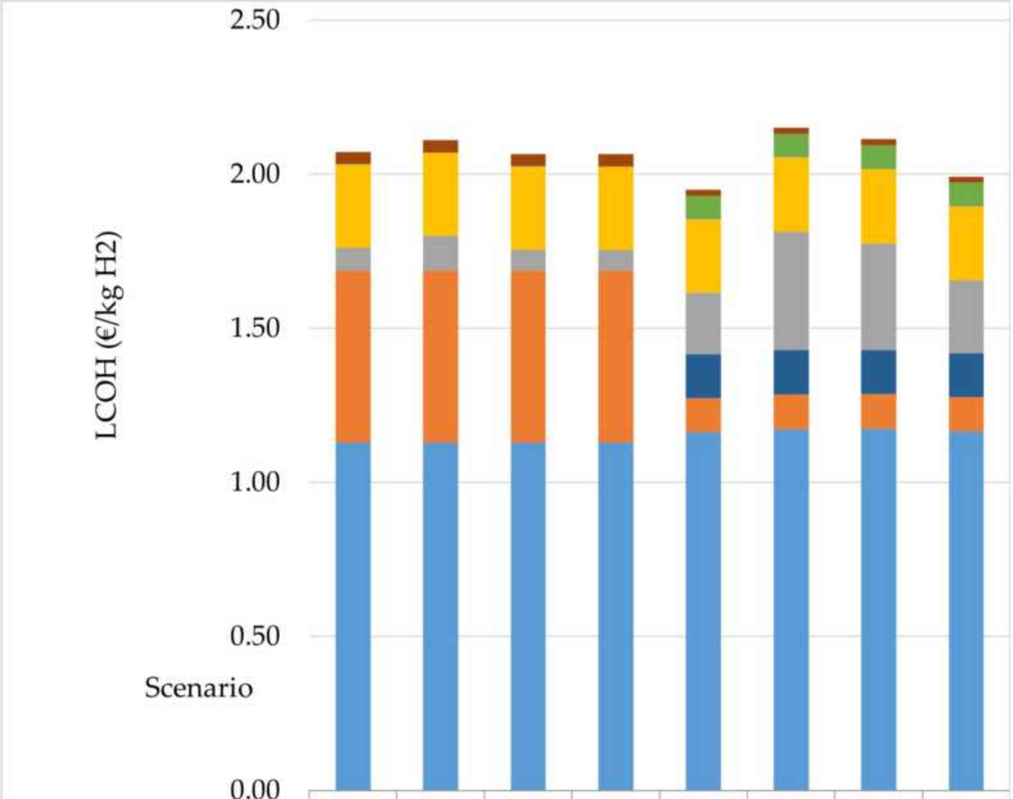
Table 16 below shows the total infrastructure capacity lengths (TICL) in TWkm for the interconnected scenarios and the isolated scenarios.

Table 16: TICL result comparison for interconnected IInt vs isolated IIso per country.

System	Country	Scenario *IInt*			*IIso*		
		TICL (TWkm)	TICL (Reused) (TWkm)	TICL (Corridors) (TWkm)	TICL (TWkm)	TICL (Reused)	TICL (Corridors)
Hydrogen	NL	23	10	9	13	4	5
	DE	11	2	7	7	3	3
	DK	4	0	4	1	0	0
	NO	26	16	8	3	2	0
	UK	29	17	8	24	9	13
Electricity	NL	22		14	14		4
	DE	9		7	7		
	DK	22		16	2		1
	NO	18		13	1		1
	UK	10		2	17		13

C.4 Levelized cost of hydrogen

Figure 47 shows the complete LCOH breakdown for all scenarios.



	H	HSpa	HIInt	HIIso	E	ESpa	EIInt	EIIso
Compressor	0.04	0.04	0.04	0.04	0.02	0.02	0.02	0.02
Onshore station	0.00	0.00	0.00	0.00	0.07	0.07	0.07	0.07
Desalinisation unit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrolyser	0.27	0.27	0.27	0.27	0.24	0.24	0.24	0.24
Network	0.07	0.11	0.07	0.07	0.20	0.38	0.35	0.24
Converter	0.00	0.00	0.00	0.00	0.14	0.14	0.14	0.14
Platform	0.56	0.56	0.56	0.56	0.11	0.11	0.11	0.11
OWF	1.13	1.13	1.13	1.13	1.16	1.17	1.17	1.17

Figure 47: Full breakdown of LCOH from every scenario.