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DECARBONIZING FREIGHT TRANSPORT:

ECONOMIC ASSESSMENT OF DIRECT SEAWATER ELECTROLYSIS FOR MARITIME HYDROGEN PRODUCTION

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ABSTRACT

The use of hydrogen and its derivates is essential for the decarbonization of freight transport, including ports and maritime logistics. Ensuring sufficient hydrogen production is therefore crucial; yet in regions with limited access to renewable and cheap energy, such as Germany, many ports rely on hydrogen imports to meet their needs. Even though large-scale hydrogen imports are necessary to meet future hydrogen demand at competitive prices, current geopolitical developments, such as the war in Ukraine and conflicts in the Middle East, highlight the vulnerability of global supply chains. Therefore, an additional local production is required to ensure resilience and independence. For the production of green hydrogen, sufficient amounts of water and renewable energy are essential. Commonly, electrolysis requires high-purity freshwater. In the near future, this reliance may cause challenges for global drinking water supply, especially but not only in arid regions. In response, the SeaEly project aims to use seawater directly as feedstock for electrolysis. This approach leverages the abundance of seawater worldwide and reduces energy consumption by eliminating the need for water pre-treatment. To achieve the project's goals, special membranes are being developed to withstand the high salinity of seawater in oppose to other current research projects focusing on the indirect seawater electrolysis. The economic effects of using seawater instead of freshwater for electrolysis, and of using different electricity sources depending on its location along the German North Sea coast, are analyzed in this work. For electricity demands, grid, renewable and surplus energy from local windfarms are considered through an analysis of the 2024 redispatch data. Overall, this analysis gives insights into the viability of Germany as a hydrogen production location. The analysis results indicate that hydrogen can be produced at minimum production costs of 4.4 €/kg in Brunsbüttel by utilizing existing wind energy surpluses.

1. INTRODUCTION

Northern Germany's emerging hydrogen production capacity and rapidly growing demands play a crucial role in the decarbonization of maritime logistics. As one of Europe's central gateways for global trade, the region offers large ports, extensive hinterland connections and energy-intensive maritime activities. Moreover, North

Germany lies at the intersection of key TEN-T corridors, such as the Scandinavian-Mediterranean and North Sea-Baltic corridor [1]. Green hydrogen and its derivatives offer a promising solution for reducing emissions from ships, port equipment, and logistics chains the electrification potential is only very limited. At the same time, strong local demand from the shipping and port industries is creating the economic pull needed to accelerate production, infrastructure development and technology deployment. The hydrogen ecosystem in northern Germany is therefore crucial for achieving climate targets and ensuring the competitiveness and resilience of maritime logistics in a decarbonizing global economy [2].

The five northern German federal states Bremen, Hamburg, Mecklenburg-Western Pomerania, Lower Saxony and Schleswig-Holstein aim to become internationally leading regions for green hydrogen. In this regard, the federal states have collaborated to formulate a unified hydrogen strategy focusing on production, import, and use of green hydrogen. The goal is that by 2027, at least 500 MW electrolysis capacity is to be installed. Until 2030, a tenfold increase to at least 5 GW is intended [2].

Currently, existing electrolysis technologies split only highly alkaline electrolytes derived from purified freshwater, via alkaline electrolysis (AEL), or purified freshwater alone by using membrane-based electrolysers equipped with proton exchange membranes (PEM) [3]. However, high purity freshwater makes up less than 1% of the global water resources [4]. In Germany, the increasing deployment of electrolysis could already exacerbate regional freshwater constraints. With further global scale-up, this challenge is likely to become even more pronounced in arid regions such as Africa, the Middle East, Southern Europe, Australia, and Western North America [4, 5]. Accordingly, it is essential to find a more sustainable way to supply the electrolysis process with water. An obvious alternative to freshwater is seawater, which accounts for 97.5% of the world's water reserves [6]. While the use of seawater does not negatively impact global freshwater availability, it can also be combined with the use of maritime renewable energy sources (RES) [4]. However, seawater contains fluctuating concentrations of salts, organic matter, microorganisms and dissolved gases, causing corrosion, side reactions and system degradation within a few hours of operation [4, 5, 7].

Currently, there are two approaches for the use of seawater: the direct seawater electrolysis (DSE) and the indirect seawater electrolysis (ISE), which combines electrolysis with seawater purification [4]. The economic viability of DSE vs. ISE is subject of ongoing discussions [4, 8, 9]. DSE is considered promising due to lower system costs, simpler operation, better scalability and a broader application potential [4]. While conventional electrolysers can in principle be used for ISE following desalination, there are currently no commercially available technologies that enable DSE. However, different sources state that the purity of freshwater derived from reversed osmosis is not compatible with the purity required for current electrolysis technologies such as PEM [5]. Therefore, additional water pre-treatment will be required. The objective of this work is to give insights into the economic opportunities of DSE. While this study analyses the most promising locations along the German North Sea coast, the model developed in the study can be extended globally to a large number of other locations, taking into account specific location factors such as transport options and the availability of RES.

Besides AEL and PEM, Anion exchange membrane electrolysis (AEM) is an emerging electrolysis technology, which operates with low-concentration alkaline solutions (≈ 1 M KOH) and uses anion-conducting polymer membranes. This technology promises lower cost and improved environmental performance in comparison to PEM and a decreased corrosion risk in contrast to AEL due to milder electrolytes. This makes AEM technology interesting for further development for DSE. However, AEM is still at lower Technology

Readiness Level (TRL) and may impair the stability and durability of membranes and catalysts under alkaline conditions. [10-14]

2. METHODOLOGY

2.1 Site selection

The five most promising regions for DSE along the German North Sea Coast are selected through a simplified site analysis. Therefore, aspects such as water availability, hydrogen storage facilities, potential hydrogen off takers, logistic accessibility, infrastructure, connection to the hydrogen core grid and availability of renewable energy (and surplus energy) are mapped.

Although the choice of location is mainly evaluated qualitatively, factors such as logistical connections, availability of seawater or brackish water, the presence of wind farms and the general availability of land carry more weight than factors such as the presence of industrial off takers and potential hydrogen storage facilities. Since the use of surplus wind energy is a main focus of this work, redispatch data from the year 2024 is analyzed through site-specific redispatch data for different windfarms. In cases where the plant-specific redispatch data cannot be assigned to a specific location, a location is estimated based on the plant operator and plant distribution. Solar redispatch is not considered in this work.

2.2 Economic Assessment

After the selection of potential production locations, the techno-economic assessment is conducted through a simulation model using AnyLogic simulation framework. Before starting the simulation, several variables must be selected to define the scenario of interest. The simulation model operates at an hourly time resolution, with all experiments conducted over a 20-year horizon to capture both short-term dynamics and long-term system evolution. The model was validated through systematic comparison with experimentally reported literature data. The model performs simulations over 20 years, in hourly resolution.

2.2.1 Electrolysis

First, the electrolysis technology is chosen. It is distinguished between AEL, PEM and AEM, whereas AEM is further divided into conventional AEM using freshwater or desalinated seawater and seawater AEM (DSE) using seawater or brackish water directly. The type of electrolysis defines the specific capital expenditure (CAPEX), operational expenditure (OPEX) and maximum yield. At this stage, these values are derived from literature [15-20]. In order to better quantify the impact of different water and energy sources, these are considered separately from OPEX. As there is currently no available literature data on DSE the CAPEX is provisionally equated with that of conventional AEM. Furthermore, the production capacity in MW is entered into the model, affecting the maximum hydrogen production per year. These values are not directly dependent on the location. The calculations for water and electricity requirements per MW of electrolysis capacity are based on Get H2 [21]. General assumptions for the following calculations can be found in Table 1.

Table 1. Basic assumptions for the economic model. This includes the minimum utilization rate for each electrolyser, the efficiency at full load operation, expected plant lifetime in years, and average stack lifetime in hours. [14, 22-24]

Technology	Min. utilization rate %	Efficiency at full load operation %	Plant lifetime a	Stack lifetime h
AEL	100	50% - 78%	20	100,000
PEM	5	50% - 83%	20	80,000
AEM	5	57% - 69%	20	35,000

Technology	Min. utilization rate %	Efficiency at full load operation %	Plant lifetime a	Stack lifetime h
DSE	5	57% - 69%	20	35,000

The minimum utilization rate refers to the minimum utilization at which an electrolyzer can be operated in dynamic mode. This is a guideline value that is assumed to be the same for PEM, AEM and DSE. In this case, it is assumed that AEL cannot be operated dynamically without further restrictions, which is why the minimum utilization rate is 100%. However, current findings show that AEL electrolysers can also be operated dynamically, which is not covered by this model.

2.2.2 Source of Water

Furthermore, the source of water can be selected. It is distinguished between seawater, brackish water, freshwater or distilled water. In all cases except DSE, the water is pre-treated to meet the standards required for electrolysis. Only distilled water does not require further treatment. In the model, the use of drinking water is priced at 4.02 €/m^3, while the price per m^3 of distilled water is 9.6 € [17, 25]. Based on Dokhani et al. [26], the cost of desalination of seawater equals 1.56 €/m^3. In the model, the same value is assumed for brackish water. According to Alwan et al. [27], the cost of further treatment of fresh water is 26.88 €/m^3. This value is assumed for all electrolysis processes except DSE.

2.2.3 Source of electricity

A further input variable within the model is the source of electricity. In dependence on the production locations, the following scenarios can be analyzed:

Scenario 1: No use of surplus electricity: In this scenario, the use of surplus electricity is not considered. Instead, electricity from the local grid, 100% green electricity from the grid (purchased through Power Purchase Agreements (PPA) or electricity produced on-site from wind or solar. The costs of electricity varies depending on the selection. According to Kost et al. [28] the costs for generating onshore wind energy in Germany lie between 0.04 €/kWh and 0.09 €/kWh, whereas the cost for generating solar electricity in northern Germany vary between 0.78 and 0.14 €/kWh. At this point, the model does not allow for a combination of self-generated wind and solar energy. The electrolysers operate at full load capacity, achieving the maximum yield.

Scenario 2: Surplus and grid electricity: In this scenario, the available electricity surpluses are being used. The respective values are for each site are analyzed based on redispatch data from 2024 reported by Netztransparenz.de [29]. Only after the surpluses have been exhausted, additional electricity purchased or self-generated electricity used for further hydrogen production. In this scenario, the electrolysers operate at full load capacity. Since there is currently no pricing schemes for surplus wind energy, but only compensation payments for curtailments of surplus wind energy, various pricing schemes can be assumed, which are discussed further in Section 3. While it can be argued that surplus energy could be free of charge and in many cases even result in negative prices for the grid operator, this pricing model assumes the minimum costs for the generation of onshore wind energy, corresponding to 0.04 €/kWh. The reason for this is that additional infrastructure is required to utilize these surpluses, such as grids directly from the wind turbines to the electrolysers, as well as electrical storage facilities that serve as short-term storage for fluctuations. Precise data on what this additional infrastructure must look like and what capacity must be stored temporarily is not yet available.

Scenario 3: Predominant use of surplus electricity: If available amounts of surplus electricity at the specific site are exhausted, grid electricity (grey or green) is purchased only until the defined minimum utilization rate of the electrolyzer is reached.

The minimum utilization rate can be found in Table 1. In addition, it is possible to conduct a series of experiments under the same conditions at all locations. For this purpose, the same type of electrolyzer and the same type of water are used at each location.

2.2.4 Transport

The model assumes that the hydrogen produced will be transported from the production site to the nearest feed point of the planned hydrogen pipeline via pressurized hydrogen containers at 500 bar with a storage capacity of 400 kg of hydrogen. Depending on the location, the containers can be transported either by rail or by lorry. The economic assumptions are depicted in Table 2. To calculate the transport costs it is crucial how far the distance to the next feed-in point is, and what costs must be estimated for the purchase and maintenance of the H2 containers. The feed-in duration of one hour per container is assumed.

It is possible to limit the number of containers (limited number of trailers). In this case, the model only generates the maximum specified number of trailers/containers per location, even if this means that a trailer/container for H2 transport may not be available at all times and therefore not all of the hydrogen produced can be fed into the grid. If, on the other hand, the number of trailers/containers is not limited, the simulation will show the number of trailers/containers used per location in the evaluation. The loading process takes one hour per container. The transport occurs immediately after either the containers have been completely filled. If rail infrastructure is available at the considered site, the containers will be transported by rail.

Table 2. Basic assumptions for the transport of gaseous hydrogen at 500 bar using trucks or rail equipped with hydrogen containers. Values are based on Meyer-Larsen et al. [30]

Transport mode	Ø Speed [km/h]	Transport capacity [kg H2]	Basic costs [€] / Rate [€/km]
Truck	40	2	150 / 1.5
Rail	70	18	0 / 41

To make the appropriate assumptions for the required transport pathway, geodata was created for potential feed-in points along the planned hydrogen core network. Hydrogen produced in WNo will be transported to BHV, which is the closest feed in point. The distance and duration of travel is calculated accordingly.

2.2.5 Yield

For the cost calculation, the electrolysis itself is viewed as a time-consumer. The yield, determined for each electrolysis technology, accounts for partially fluctuating utilization under scenarios relying exclusively on surplus electricity, exclusively on grid electricity, or on a combination of both when surplus supply is inadequate. If only surplus energy is used and the electrolysers cannot be operated at 100% capacity, the yield is calculated using the efficiency curve shown in Figure 1.

The illustrated efficiency curve is based on the operation of a PEM electrolysers. Since similar curves under comparable conditions are not available for AEL, AEM or DSE, the PEM curve is used as a generic proxy. For AEL, AEM and DSE, the curve is vertically shifted to reach the full-load efficiencies as depicted in Table 1.

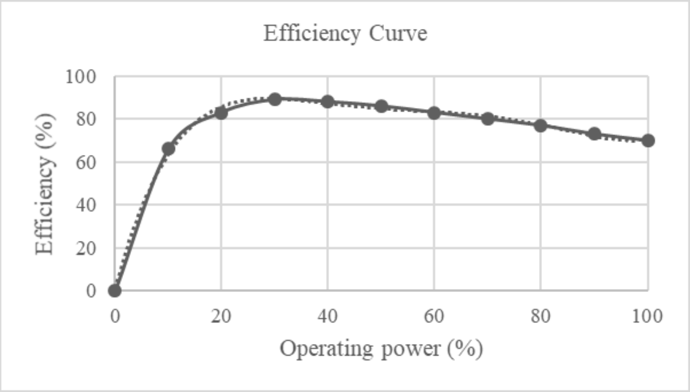

Figure 1: Simplified efficiency curve for PEM from Astriana et al. [31]. An adjacent polynomial function was created based on the data. [31, 32]

The yield calculated for the corresponding electrolyzer specifies how often one ton of H2 is produced per year, which triggers the transport process and subsequent feed-in to the hydrogen core network. Depending on the parameter selection for an experiment and the data import, the maximum yield of the electrolyzer varies based on the production location.

In addition to investment and operating costs, the Levelized Cost of Hydrogen (LCOH) also includes the costs of electricity and water incurred for the electrolysis process. The total hydrogen price also includes transport costs to the feed-in point and trailer/container costs.

3. RESULTS & DISCUSSION

Before analyzing the differences between the various locations, the direct influences of the various electrolysis technologies as well as the influence of different energy sources on the LCOH are analyzed.

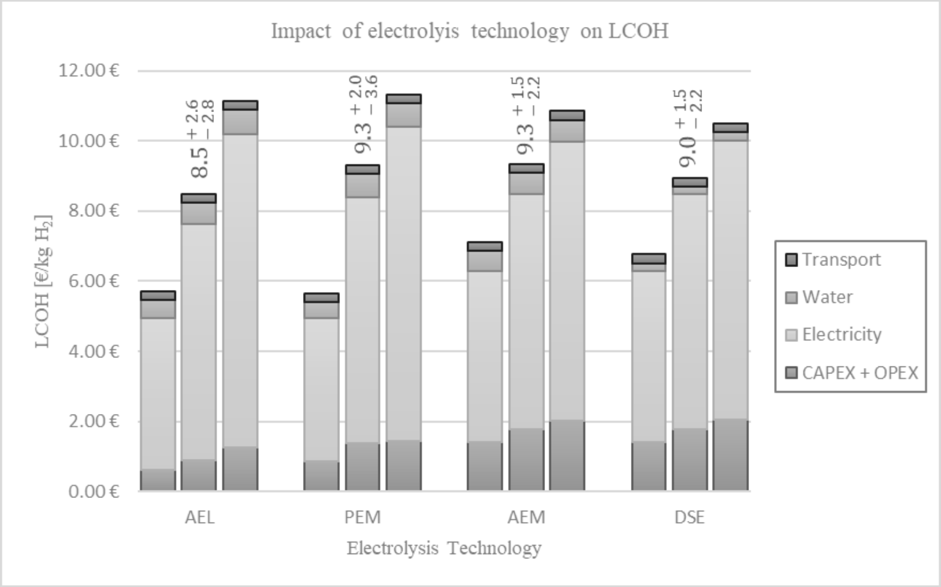

Figure 2: Assessment of the economic impact of the electrolysis technology. The stacked columns show the respective share of the individual cost components (CAPEX + OPEX, water, electricity and transport) of the total Levelized Cost of Hydrogen (LCOH) in €/kg H2. Three stacked columns are shown for each technology, indicating the average value, as well as the minimum and maximum LCOH. The different technologies include alkaline electrolysis (AEL), proton exchange membrane electrolysis (PEM), anion exchange membrane electrolysis (AEM) and direct seawater electrolysis (DSE).

As depicted in Figure 2, one key difference between the LCOH lies in the CAPEX and OPEX (excluding electricity and water). The CAPEX and OPEX lowest for alkaline electrolysis with a value of 0.88 €/kg of hydrogen caused by its less expensive materials and TRL. CAPEX and OPEX are highest for AEM and DSE with 1.78 € per kg H2.

Due to the lack of empirical data and the ongoing technological development, DSE is assumed to have the same CAPEX as AEM. However, given the currently low TRL, the CAPEX of first-generation DSE prototypes is expected to significantly exceed these values. The assumptions therefore represent optimistic projections for future DSE costs at a higher TRL. In addition, the model assumes that the stack durability of DSE will be comparable to that of AEM. Taking into account various side reactions as described in various studies on DSE, such as chlorine evolution reactions, oxygen evolution reactions, biofouling and the overall low durability due to complex ion composition in seawater, the stack lifetime of DSE is certainly significantly shorter than that of AEM [3-5, 7-9, 33]. Nevertheless, current research in the field of DSE focuses on design adaptations of electrocatalysts, electrodes and interfaces with passivating ion/protective layers, tailoring of chloride adsorption sites, inhibition of hydroxide ions binding to Mg^{2+} and Ca^{2+}, and the use of anti-corrosion materials, which aim to significantly improve the stack lifetimes of DSE [33].

At full load operation, PEM shows the lowest efficiency of 60.0%, whereas AEL reaches an efficiency of 62.5% [34]. AEM and DSE are expected to reach an efficiency of 63.0% at full-load operation [34]. Therefore, the cost of electricity reach slightly higher values for PEM, resulting in LCOHs of 7.03 €/kg in comparison to AEL with 6.75 €/kg H2 and AEM and DSE with 6.69 €/kg H2. The cost for freshwater and pre-treatment for AEL, PEM and AEM differ only slightly with an average value of 0.63 €/kg H2. This value decreases for DSE, which uses free-of-charge seawater. The costs of 0.17 €/kg H2 originate from the operational water for which freshwater is used. In this scenario, the same location is assumed for all electrolysers to simplify the comparison. Therefore, the cost for transport equals an average value 0.25 €/kg H2 for all technologies, assuming transport by truck to the closest hydrogen core network point.

In the worst-case scenarios, in addition to the extra 20% on all key parameters, an average utilization rate of 80% is assumed. Based on current knowledge, the assumption that electrolysers can be operated exclusively with fluctuating renewable energy and still run continuously at a utilization rate of 100% are likely to be too optimistic due to dynamic constraints. However, the effects of these inaccuracies are relativized to a certain extent due to the efficiency behavior depending on the utilization rate, as shown in Figure 1. It can be concluded, that the price of electricity has most significant impact on the LCOH with a share of 71% to 79%. The cost for water contributes to only 7% to 8%. Using seawater for the electrolysis, the share of cost attributed to water can be reduced to less than 3%. In the economic model, the same pre-treatment price is assumed for brackish water and seawater. While this assumption may not be realistic due to different ion concentrations in both water sources, the overall magnitude of cost for pretreatment are expected to be adequate.

For the base-scenario in Figure 2, the use of electricity from the German power grid is considered. In July 2025, the share of renewably sourced energy in the national grid reached 67.5% [35]. However, to produce green hydrogen, the use of 100% renewable energy is required. Using PPAs, all plants could potentially be operated with 100% renewable energy. However, this would increase the LCOH by 260% due to the higher costs of electricity as illustrated in Figure 3. Alternatively, it is possible to operate the electrolysers with renewable energy produced on-site. In this case, electricity production costs are treated as equivalent to electricity costs. Since different locations and weather conditions influence the cost per kWh, a distinction is made between a minimum and a maximum electricity generating price. For solar energy, the resulting LCOH lie between 6.9 and 11.0 €/kg. However, the lowest LCOH can be achieved using wind energy, resulting in 4.8 to 7.0 €/kg.

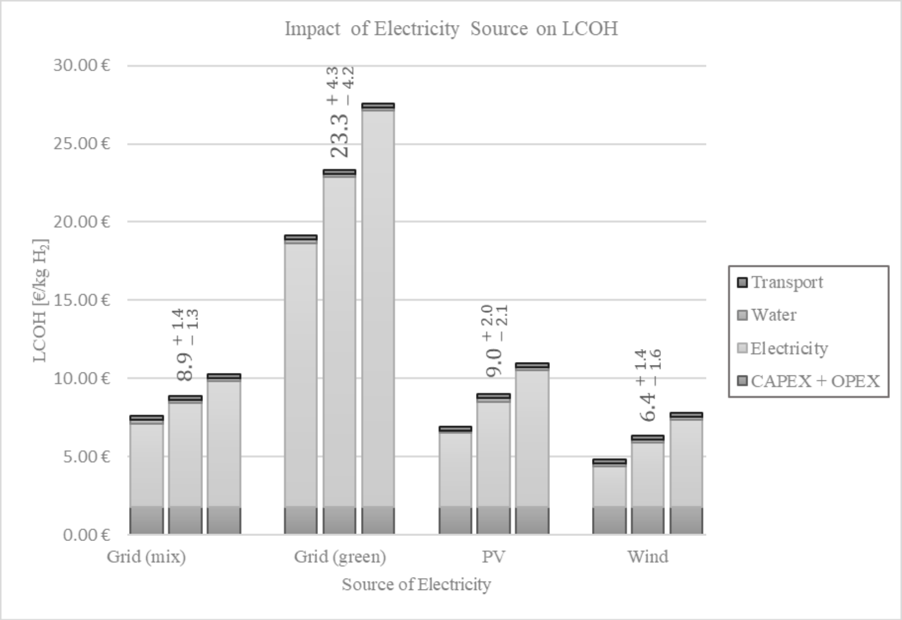

Figure 3: Assessment of the impact of different electricity sources on the Levelized Cost of Hydrogen (LCOH) for direct seawater electrolysis (DSE), including electricity from the German grid, purchase of 100% renewable electricity and the cost of operation PV or wind plants with a minimum and a maximum operation price. The stacked columns show the respective absolute share of the individual cost components (CAPEX + OPEX, water, electricity and transport) of the total LCOH in €/kg H2. Three stacked columns are shown for each technology, indicating the average value and the minimum and maximum LCOH.

Due to the large impact of the price of electricity on the LCOH, different sources of electricity are analyzed. However, when considering potentially available wind energy surpluses, the specific production location is decisive. To select locations for the following economic assessment, the North Sea Coast region is analyzed by taking into account existing or planned hydrogen infrastructure including hydrogen pipelines and storage capacities, potential industrial hydrogen offtakers, the access to renewable energy including onshore and offshore wind and availability of seawater or brackish water. In Figure 4, the five promising locations are marked with circles. The location Wurster Nordseeküste is further divided into Wurster Nordseeküste (WNo) and Bremerhaven (BHV). While the locations Bremen (HB), Hamburg (HH) and BHV offer the advantages of existing hydrogen infrastructure, good logistical connections and short distances to potential offtakers, the locations Wilhelmshaven (WHV), WNo and Brunsbüttel (BB) were selected due to their direct access to seawater as well as the large availability of renewable electricity. Considering hydrogen not only as a future fuel for hard to abate sectors, but also as a mobile energy storage solution, the grid-friendly production of hydrogen is essential. This entails that hydrogen is produced predominantly at times of oversupply of renewable electricity. To obtain more information on the times, locations and amounts of oversupply, the northern German redispatch data is analyzed in this work.

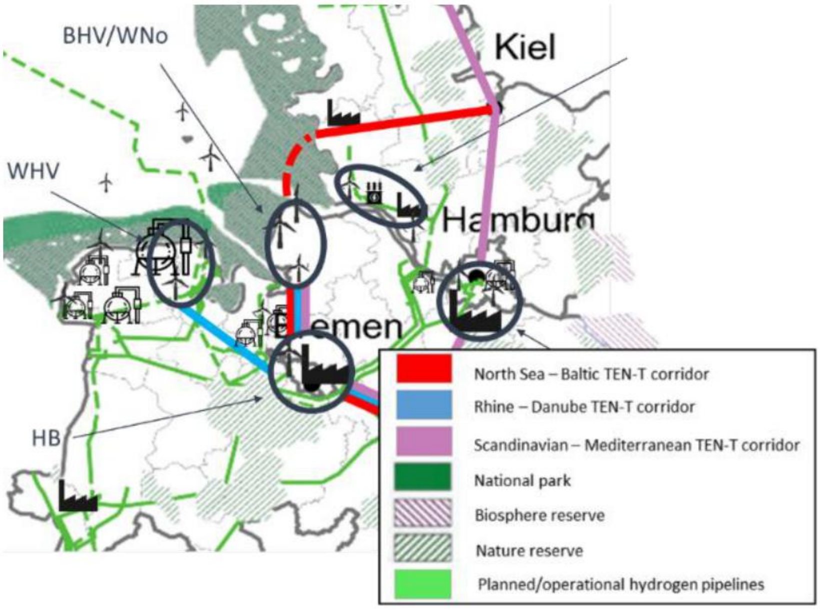

Figure 4: Preliminary selection of promising seawater electrolysis locations along the German North Sea coast. The figure includes the planned or partly operational hydrogen pipeline in northern Germany, TEN-T corridors, protected areas, potential hydrogen off takers, storage facilities and wind parks.

The analysis shows the largest redispatch measures in the locations WHV and BB. Especially in BB, the large amounts of surplus energy partly results from the landing of offshore wind energy at the port of BB [36]. Less redispatch occurs in the area of WNo. However, because the individual plants could not always be clearly assigned to a specific location, some inaccuracies are to be expected, particularly in the WNo region. For the cities of BHV, HB and HH no redispatch data was reported during 2024. This may be due to the fact that the wind turbines in these cities were assigned to other regions, such as Lower Saxony and therefore cannot be specifically attributed to the locations. On the other hand, however, it is also possible that there are not actually too many redispatch measures in these cities. According to Heitkoetter et al. [24], redispatch is directly linked to the regional energy demand and the installed capacity. Therefore, redispatch measures usually occur in regions where energy demands are low. In places where energy demand is continuously high, for example in industrial cities of BHV, HB, and HH, redispatch does not occur frequently.

While this model assumes costs for wind energy surpluses comparable to the minimum costs for the production of onshore wind energy, various assumptions are conceivable for the pricing of wind energy surpluses, which may be based on infrastructure costs and compensation payments for feed-in bottlenecks. Prior to 2021, as part of feed-in management, all curtailed renewable energy plants, as well as nuclear power plants, were compensated under the Renewable Energy Sources Act [37] if their feed-in was reduced to stabilize the grid. Since Redispatch 2.0 (October 2021), a uniform procedure has been in place in accordance with Section 13a of the German Energy Industry Act (EnWG) [38], which covers all generation and storage plants above 100 kW (as well as smaller remote-controlled plants). These operators continue to receive financial and accounting compensation for lost revenue. Plants below the threshold or without remote control capability, on the other hand, are often no longer taken into account. Redispatch 3.0 is currently being discussed, dealing with the question of whether producers above 100 kW should also no longer receive compensation [39].

One argument in favor of allowing surplus energy to be used free of charge is that this energy would otherwise remain unused, while grid operators currently provide compensation for curtailment in the case of plants with capacities exceeding 100 kW. On the other hand, it is foreseeable that network operators will no longer cover the cost of the outage if the surplus energy is used elsewhere. Accordingly, financial incentives must be created for wind turbine operators to make surplus electricity available for electrolysis purposes. In addition, cables running directly from the electrolyzer to the wind farms and sufficient battery storage capacity are required to utilize the surplus energy. While PEM and AEM in particular can respond relatively quickly and flexibly to fluctuations in production, battery-based intermediate storage of the energy will be essential. Both will contribute to the costs for surplus electricity.

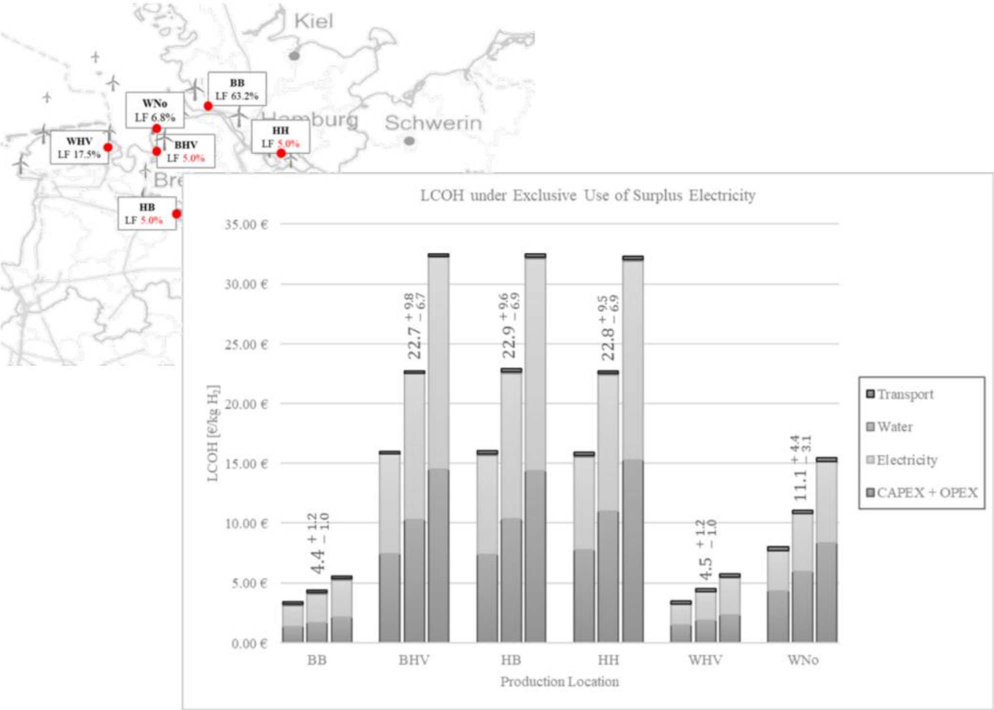

Figure 5: Location specific Levelized Cost of Hydrogen (LCOH) for the exclusive use of surplus electricity for direct seawater electrolysis (DSE). The stacked columns show the respective absolute share of the individual cost components (CAPEX + OPEX, water, electricity and transport) of the total LCOH in €/kg H2. Three stacked columns are shown for each location, indicating the average value and the minimum and maximum LCOH.

As an alternative to using surplus electricity, which is compensated for by grid electricity at 100% utilization, this work also analyses the exclusive use of surplus energy. The results are illustrated in Figure 5. When operating electrolysers dynamically, the highest efficiencies can be observed at 30% capacity as depicted in Figure 1. However, below a load factor of 30%, the efficiency drastically decreases. A minimum utilization rate is set at 5% since operation below this threshold might not only cause a significant loss of efficiency but may also negatively affect the overall lifetime of the stacks. Therefore, if the supply of surplus energy is not sufficient for a utilization rate of 5%, grid electricity is used to compensate the set minimum. This is the case for BHV, HB and HH, where no redispatch measures are reported. Since the overall efficiency decreases significantly below the optimum of 30%, the operation at 5% results in high CAPEX and OPEX in relation to the H2 yield. Therefore, LCOH reach 22.7 €/kg to 27.9 €/kg H2. In these cases, a total shutdown of the plants would be justifiable.

Alternatively, a more profitable option here would be to use the excess energy solely as compensation for continuously available energy sources in order to operate the electrolysers more efficiently.

The lowest LCOH with a value of 4.4 €/kg H2 is observed in BB where a 10 MW electrolysers can operate at an average utilization rate of 63.2% by exclusively using surplus electricity. However, WHV with an average utilization rate of 17.5% reaches competitive LCOH of 4.5 €/kg.

4. CONCLUSION

Referring back to the debate on the competitiveness of DSE, the analysis results conclude that the purely economic added value of DSE is indeed negligible. However, this does not detract from the environmental benefits of DSE. This study concludes that, in northern Germany, coastal locations such as Wilhelmshaven, Brunsbüttel, and the Wurster Nordseeküste are particularly valuable sites for future green hydrogen production due to their excellent supply of wind energy. Moreover, sites at these locations ensures reliable access to seawater. If the focus is on directly coupling wind turbines with electrolysers to utilize surplus energy in the future, then decentralized, compact electrolysis units are particularly advantageous. This in turn argues in favor of DSE over ISE. However, this presupposes the successful testing and maturing of technologies for DSE to higher TRL. In addition, further regulatory framework conditions are required to enable the utilization of surplus energy.

At this stage, the simulation model uses solely literature data to analyze the potential hydrogen production costs. Especially for DSE, literature data for commercial electrolysers is not available yet. Even though the required remaining research regarding DSE as well as the low TRL would lead to disproportionately high CAPEX for DSE at this point in time, significant cost reductions are expected as the TRL increases. Future findings regarding the DSE should be used to validate the assumptions in the model. Furthermore, future work should focus on defining viable pricing schemes for surplus wind energy as well as overcoming the technical hurdles in operating electrolyzers with surplus electricity as well as further fluctuating renewable energy sources. While brine disposal strategies and further environmental effects of DSE exceed the scope of this work, it is important to include this in the overall assessment of the DSE.

In the near future, the port ecosystems are expected to heavily rely on hydrogen and its derivates where both serve not only as a mobile energy storage medium but also as a fuel for heavy duty applications such as port equipment, port rail, trucks, and vessels. Ports will therefore need to focus on establishing sufficient bunkering and supply infrastructure. The results of this work confirm that DSE can help northern German seaports meet part of their own hydrogen demand in an economically competitive way. Furthermore, DSE can help regions with cheaper renewable energy expand their hydrogen export opportunities without affecting regional fresh water availability.

5. ACKNOWLEDGEMENTS

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