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WHITE PAPER

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**NOVEMBER 2020**

WHITE PAPER

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PRELIMINARY OVERVIEW FOR AN IMMEDIATE DECARBONISATION OF MARITIME TRANSPORT


| | |
|---|---|
| Alessandro Singlitico | Center for Electric Power and Energy, Department of Electrical Engineering, Technical University of Denmark, 2800 Kongens Lyngby, Denmark. Contact author: alesi@elektro.dtu.dk |
| Nicolas J. B. Campion<br>Marie Münster | Department of Management, Technical University of Denmark, Engineering, Produktionstorvet, Building 424, 2800 Kongens Lyngby, Denmark |
| Matti Koivisto<br>Nicolaos A. Cutululis<br>Cathy J. Suo | Department of Wind Energy, Technical University of Denmark, Frederiksborgvej 399, 4000 Roskilde, Denmark |
| Kenneth Karlsson | Energy Modelling Lab ApS, C/O EnergyHub Sundkaj 125, 2150 Nordhavn, Denmark |
| Torben Jørgensen<br>Jeppe Eimose Waagstein | Bornholms Energi & Forsyning, Skansevej 2, 3700 Rønne, Denmark |
| Maja F. Bendtsen | Rønne Havn, A/S, Sydhavnsvej 12, 3700 Rønne, Denmark |

# ACKNOWLEDGEMENT

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# EXECUTIVE SUMMARY

Bornholm plays a central role in the future offshore power expansion in the Baltic Sea and as a node between future interconnections between countries. The necessity to store/convert surplus power puts Bornholm in position to be the first natural energy hub. Bornholm can be not only the centre for electrical equipment such as substations but also a centre for P2X production from offshore wind power. The production of electrofuels through P2X technologies can penetrate the transport sector in Bornholm, the hardest to decarbonise, starting with the high-speed ferries to Ystad and Køge, which use in Rønne Havn as their base. The needs to comply with existing and imminent stricter regulations create the necessity for an immediate transition, before a fleet renewal. Therefore, this study investigates the conversion of the hydrogen, produced using offshore wind electricity, into methanol, whose use as a fuel is mature and does not require substantial changes to the fleet.

In this work, three placements for a P2X facility, with a size able to satisfy Rønne Havn demand, are investigated: inside the wind turbines, in Bornholm and Copenhagen.

The following results are reached.

- The fuel demand for the ferries in Rønne Havn, including all the operations in the port, is estimated to be 237,000 MWh per year (equivalent to 23,300 $m^3$ diesel per year).
- The high consumption of the high-speed ferry currently used creates a barrier to the direct electrification of the ferry, due to the high capital cost of the battery and low energy density.

- If the electrolyser can access only the electric energy from a 2 GW offshore wind power park near Bornholm, the cost of producing hydrogen in Bornholm is lower than the case in which it is produced in Copenhagen or inside the wind turbine, with a cost of 3-4 €/kg.
- The cost of producing $H_2$ in Bornholm and transmitting it via a pipeline to Copenhagen is on the same range of producing the hydrogen in Copenhagen.
- The production of hydrogen in Bornholm benefits the utilisation of the HVDC line transmitting the remaining electricity to Copenhagen.
- The cost of producing hydrogen is in line with the cost of green $H_2$ in Europe (2.8-3.6 €/kg), but it is higher than its fossil counterparts, grey $H_2$ (0.8-2.9 €/kg) and blue $H_2$ (1.35-2.6 €/kg).
- The amount of $CO_2$ potentially available from biomass, currently combusted in CHP plants and potentially available for anaerobic digestion, is estimated to be equivalent to 31,423 tonnes per annum, from which 22,853 tonnes per annum of methanol can be produced, equivalent to 126,325 MWh. Therefore, the $CO_2$ is the limiting reactant in the methanol production if the plant is placed on Bornholm.
- If the access to the public grid is guaranteed to maintain the production of methanol without shutdowns, a 62.4 MW electrolyser followed by a methanol plant would be required to satisfy the demand for ferries Rønne Havn. However, a 27.6 MW electrolyser would produce the amount of hydrogen that can be converted to methanol, considering the limited $CO_2$ sources.
- If the methanol production is placed in Bornholm to satisfy Rønne Havn demand, the green fuel can be produced at 800 €/t, in the case there is no limitation of $CO_2$ sources, or at 867 €/t in case of limited $CO_2$ sources.
- If all the by-products of the electrolysis, oxygen and heat are sold, the cost of production of methanol is reduced to 590 €/t, or 660 €/t in case of limited $CO_2$ sources.
- The cost of the methanol produced in Bornholm is in line with cost ranges for green methanol (260-1,060€/t.). However, the costs result higher than the selling price of fossil methanol ca. 275 €/t.
- In conclusion, the placement of the P2X facility results to be more cost-effective in Bornholm, in the case of only-hydrogen production. However, if hydrogen is

converted into methanol, the larger access to $CO_2$ sources would favour the placement of the methanol production plant in Copenhagen.

- The access to low-cost electricity from renewables and the efficient use of by-products are vital for the production of electrofuels able to compete with the existing fossil counterparts.

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## ABBREVIATIONS

| | |
|---|---|
| AC | Alternate current |
| AEL | Alkaline electrolyser |
| CF | Capacity factor |
| DC | Direct current |
| GHG | Greenhouse gas |
| HFO | Heavy fuel oil |
| HVDC | High voltage direct current |
| LCOE | Levelised cost of electricity |
| LCOH | Levelised cost of hydrogen |
| MGO | Marine gas oil |
| NECA | Nitrogen emission control area |
| OWPP | Offshore wind power park |
| PEMEL | Proton exchange membrane electrolyser |
| SECA | Sulphur emission control area |
| SOEL | Solid oxide electrolyser |
| VSC | Voltage source converter |
| WT | Wind turbine |

# 1 WHY WE WROTE THIS PAPER

The Danish Parliament has recently approved the plan to expand with 6 GW the offshore power in Denmark, of which 1 GW wind farm, and two Energy Islands, one in the North Sea of 3 GW and one around Bornholm of 2 GW. This agreement has the goal to abate 3.4 million tonnes of $CO_2$ equivalents in 2030, while boosting the economic recovery with a green transformation of the industry. The energy from the islands will also eventually be utilised by Power-to-X (P2X) technologies that can store or convert electricity into green fuels. The agreement includes a tender to support the establishment of large-scale P2X plants with a total capacity of 100 MW. The new agreement also contributes to a greener transport sector and funds will be targeted for projects relating to charging stations, heavy transport, ferries, etc. [1].

This White Paper aims to provide a preliminary overview of the effects of the placement of P2X facility, considering a 2 GW offshore power expansion around Bornholm, which aims to immediate decarbonisation of maritime transport, in the specific case of Rønne Havn. The three alternative P2X placements discussed in this paper are (i) inside the wind turbine, (ii) on Bornholm, and (iii) in Copenhagen (Figure 1).

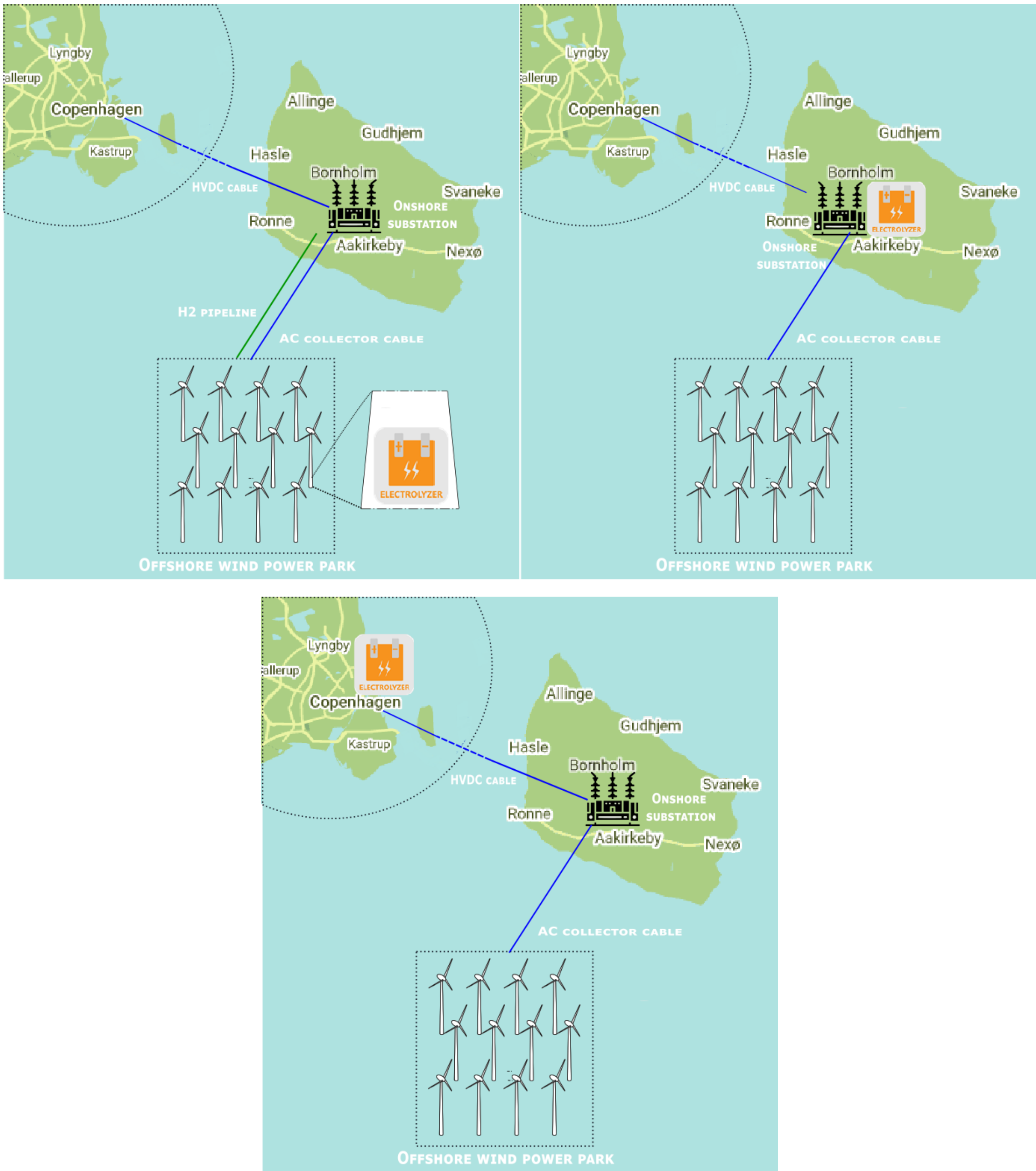


Figure 1. Alternative placement for the P2X facility (e.g. electrolyser): (i) inside the wind turbine, (ii) on Bornholm, (iii) in Copenhagen.

## 1.1 WHITE PAPER OUTLINE

In Chapter 2, an overview of the shipping sector is provided. The economic and environmental impact and the current regulations and targets are described. The position of Denmark regarding P2X technologies deployment, and the targets of the island of Bornholm and Rønne Havn are presented.

In Chapter 3, a description of the main challenges regarding the power system expansion of 2 GW around Bornholm. Among which, the energy losses to which large offshore wind power parks are subjected, costs and feasibility of the integration of the system and interconnections to over-sea countries.

In Chapter 4, the cost of the produced hydrogen ($H_2$) and the cost of the electricity delivered onshore are investigated for the three possible placements, in the case the of the power and the P2X infrastructures run in parallel, over the 2 GW offshore wind power farm.

In Chapter 5, the electrolyser is assumed to be connected to a public grid and the $H_2$ is assumed to be converted into methanol and the cost of its production is investigated for the three possible placements. The theoretical amount of $CO_2$ available in Bornholm for producing methanol is estimated. Moreover, the impact of selling by-products of the electrolysis (oxygen and heat) is explored.

In Chapter 6, the pros and cons of the three placements are listed, and additional alternative visions for P2X technologies in Bornholm are presented for future investigations.

# 2 BACKGROUND

Maritime transport is the backbone of international trade and the global economy, around 80% of global trade by volume is carried by sea [2]. The maritime sector is a relevant portion of the Danish Economy. Denmark has 2.55% of the global fleet economic value 2019, 13th country in the world [4]. Moreover, Danish maritime companies account for the employment of 100 thousands persons, of which 60% directly employed, corresponding to 3.4% of the total employment in Denmark. The value produced accounts for DKK 350 billion, corresponding to 8.9% of the overall Danish economy [5].

## 2.1 ENVIRONMENTAL IMPACT OF THE SHIPPING SECTOR

The greenhouse gas (GHG) emissions of shipping have increased from 977 million tonnes in 2012 to 1,076 million tonnes in 2018 (9.6% increase), of which 1,056 million tonnes are $CO_2$ emissions. The share of shipping emissions in global anthropogenic emissions is 2.89% in 2018. Emissions are projected to increase to 90-130% of 2008 emissions by 2050 for a range of plausible long-term economic and energy scenarios [3].

In 2018, in the EU 138 million tonnes of $CO_2$ are emitted by the shipping sector, 3% of total EU emissions, which are likely to grow in the future. 70% of the fuel consumed was heavy fuel oil (HFO), the remnant from the distillation and cracking process of crude oil, distinguished for the low cost and the heavier environmental impact when compared to other fuel oils [4].

At present there are no IMO regulations on $CO_2$ emission; however the shipping industry have volunteered to reduce emissions by 40% in 2030 and 70% in 2050 compared to 2008; and a reduction of the total annual GHG emissions by at least 50% by 2050, compared to 2008 [5]

Besides the $CO_2$ emissions, other pollutants are subjected to restrictions. Besides a global sulphur cap, there are specific emission control areas with stricter regulation in regions that are more sensitive to pollution. There are sulphur emission control areas (SECAs) with a 0.1% sulphur limit located in the Baltic Sea, North Sea, the English Channel, and waters 200 nautical miles from the coasts of the USA and Canada [6][7]. NOx-emissions are also regulated. Engines installed on ships on or after 1 January 2016 operating in nitrogen emission control areas (NECAs) need to comply with Tier III NOx emission standards, between 2.0 - 3.4 g NOx/kWh, depending on the engine's rotation per minute (rpm) [8].

## 2.2 THE RISE OF P2X

The shipping industry has a growing interest in fossil-free fuels to comply with regulations. For ships built after 2020, there is IMO regulation putting a cap on NOx emissions, meaning that the ship cannot use either marine gas oil (MGO) or heavy fuel oil (HFO) without additives, which reduce the NOx emission. Adding additives is expensive and will require additional supplies to the engines, therefore many ships will instead be built to sail on alternative fuels such as LNG, ammonia or methanol, which will not cause the same NOx emissions.

In addition to the electrification, plans for the conversion of power into renewable fuels to decarbonise also the transport sector have been announced. A partnership between Copenhagen Airports, A.P. Møller-Mærsk, DSV Panalpina, DFDS, SAS and Ørsted has been formed to develop an industrial-scale production facility to produce sustainable fuels for road, maritime and air transport in the Copenhagen area in three stages. During the first phase, a 10 MW electrolyser, producing renewable hydrogen ($H_2$) used directly to fuel busses and trucks, is going to be operational. In phase two, a 250 MW fed by the offshore wind power from Bornholm, will be combined with carbon capture technologies in the Greater Copenhagen area to produce renewable methanol for maritime transport and renewable jet-fuel for the aviation sector. In phase three the capacity of the electrolyser would be extended to 1.3 GW and capture more $CO_2$. The project has the potential to displace 5% of fossil fuels at Copenhagen Airport by 2027 and 30% by 2030 [9]. Another study by A.P. Møller-Mærsk and Lloyds Register [10] confirms that the best opportunities for decarbonising shipping lie in new sustainable energy sources, among which, alcohol, biomethane, and ammonia. In August 2020, another partnership between Alfa Laval, Hafnia, Haldor-Topsoe, Vestas and Siemens-Gamesa released a study regarding ammonia utilisation as a maritime fuel, concluding that ammonia is an attractive and low-risk choice of marine fuel both in the transition phase towards a more sustainable shipping industry and as a long-term solution [11].

## 2.3 BORNHOLM – THE ENERGY ISLAND

The Danish island of Bornholm, lying in the Baltic Sea, is going to be at the heart of this offshore wind power expansion. Already at the forefront of a green transition, Bornholm has embraced the green agenda for over 30 years [12], setting very ambitious goals:

- By 2025, Bornholm has to be a 100% carbon-neutral energy production.
- By 2032, Bornholm will be a zero-waste society.
- By 2035, Bornholm will be a zero-emission island.

The electricity production on Bornholm integrates 37 MW wind turbines, 23 MW PV and 3 MW biogas, for a total capacity of 63 MW. Moreover, a 60 MW cable connects the island to Sweden. The annual heat and power generation is shown in Table 1.

Table 1. Annual heat and power generation in Bornholm (2018)[13].

| | POWER | HEAT |
|---|---|---|
| SEA CABLE TO SWEDEN | 10,000 MWh /<br>103,000 MWh (export/import) | |
| COMBINED HEAT AND POWER PLANT | 40,000 MWh | 115,000 MWh |
| WASTE INCINERATION | | 50,000 MWh |
| LARGE WIND TURBINES | 85,000 MWh | |
| SMALL WIND TURBINES | 1,000 MWh | |
| LARGE PV | 15,000 MWh | |
| SMALL PV | 8,000 MWh | |
| HEAT PLANTS | | 137,000 MWh |
| BIOGAS | 9,000 MWh | 6,000 MWh |

The transport sector remains one of the most important $CO_2$ contributors. However, to date, only the path of transport electrification has been explored, but there is no project concerning fuel substitutions with renewable alternatives such as P2X. Being in the centre of a GW-scale expansion of offshore wind power makes Bornholm a strategic area, as a node for interconnections and storage/conversion of power, with the chance to fully decarbonise its energy demand and become a net exporter of electrofuels. The vision of Bornholm as an energy island was firstly introduced in November 2019, by Ørsted, which envisioned Bornholm as the centre point of a proposed new interconnection between Denmark and Poland.

## 2.4 STUDY CASE: RØNNE HAVN

Because of its favourable position close by a future offshore wind power park (OWPP), Rønne Havn can be a potential site for P2X production, along with the existing visions and plans for large-scale P2X production in Copenhagen.

Rønne Havn A/S (Figure 2) is the largest traffic and commercial port on the Danish island of Bornholm with more than 3,000 ships calling at the Port every year. It is a landlord port, meaning that the port provides the infrastructure (dredging, quays and terminal paving) whilst part or all of the superstructure is owned and financed by private companies which are also employing the stevedoring labour.

Figure 2. Aerial photograph of Rønne Havn.

Regularly scheduled ferries connect Rønne to mainland Denmark, Sweden and Germany. Bornholmslinjen operates a catamaran (high-speed passenger ferry) to Ystad (Sweden), from where there is a direct train line to Copenhagen (Denmark). There is also daily a direct ferry line to Køge, and seasonal connection to Sassnitz in Germany. The current catamaran consumes 13.2 $m^3$ of MGO on one return-trip. With four daily return trips, 365 days a year the annual fuel consumption is 19,272 $m^3$ or 195,996 MWh per year. A total energy consumption, including all the operations in the port, is equivalent to 237,000 MWh per year (equivalent to 23,300 $m^3$ diesel per year) [14].

In this case, the replacement with a fully-electric ferry would be less favourable than other fuel alternatives, due to the low energy density of batteries (and a consequential high volume and weight requirement) and the high capital costs [15]. In fact, a new catamaran, arriving in spring 2022 would be ready for alternative fuel, making it the obvious candidate to be a first customer for renewable fuels that can be produced in Rønne.

The short-term ambition of Rønne Havn A/S is to decarbonise its operations in the port and to comply with the regulations, with the future vision to provide alternative fuels for the rest of the vessels in the port and potentially vessels passing by and bunkering (see Figure 3).

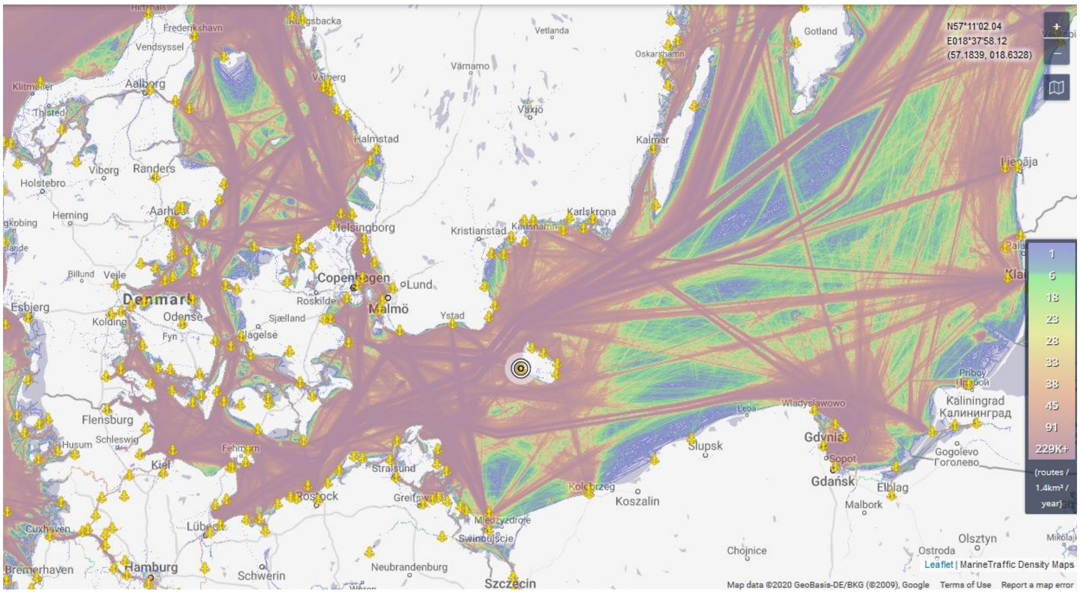


Figure 3. Marine traffic surrounding Bornholm (https://www.marinetraffic.com).

# 3 OFFSHORE POWER EXPANSION IN THE BALTIC SEA

Current wind power peak in Denmark was 6,121 MW in 2018, of which 4,420 MW of onshore and 1,701 MW of offshore wind power, respectively. The total power peak capacity of Denmark is 15 GW [16], while Bornholm power capacity is 55 MW.

## 3.1 WIND ENERGY RESOURCES

The Baltic Sea is foreseen to experience major offshore wind development, with 83 GW of installations in the WindEurope 2050 offshore wind vision [17]. Although mean wind speeds are somewhat lower than in the North Sea, capacity factors (CFs) in the Baltic Sea are comparable to the North Sea, with most locations reaching high CF of more than 0.5 (see Figure 4). Resource assessments in both Global Wind Atlas [18] and New European Wind Atlas [19] cover the whole of Baltic Sea. Besides, e.g., sea depth assessment is required to find the optimal OWPP location.

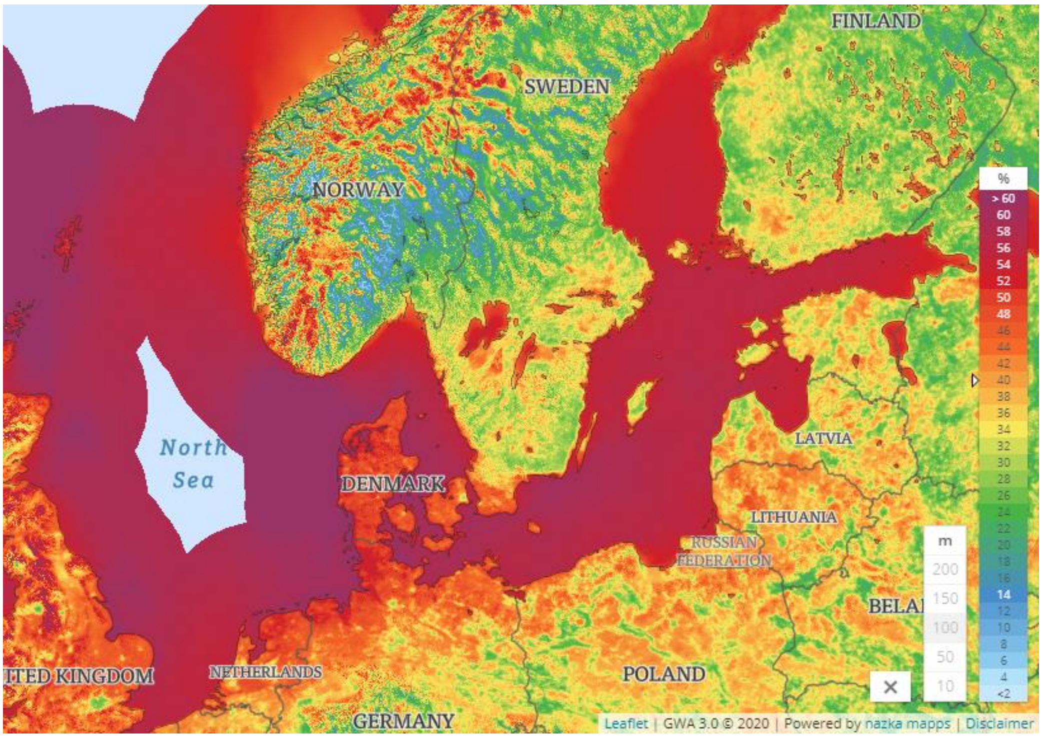


Figure 4. Capacity factors in the Baltic Sea and the North Sea, assuming 100 m hub height and IEC Class I turbine. Wake or other losses are not considered [17].

### 3.1.1 LARGE-SCALE WAKE LOSSES

The CFs shown in Figure 4 do not take wake and other losses into account. When multi-GW installations are located in a small geographical region, wake losses can get very large. In [20], wake losses up to around 50% for the German North Sea were found. Although such high losses are for scenarios with tens of GW of offshore installations, even on a 2 GW level, wake losses need to be considered. In addition to wake losses inside a farm, farm-to-farm wakes need to be analysed if OWPPs are located close to each other. The Weather Research and Forecast model can be used for such modelling [21], and even engineering wake models can be applied to model farm-to-farm wake losses [22].

### 3.1.2 WIND GENERATION VARIABILITY

In addition to the CF, generation variability is important when assessing system impacts. In [22], scenarios with 4.4 GW of offshore wind in Belgium were studied. Due to the limited size of the Belgian offshore area, generations from the OWPPs are highly correlated. This leads to large aggregate generation ramps, which can be challenging for the power system. Similar behaviour can be expected if the 2 GW of installations is located within a small region. Generation variability also impacts on revenues from electricity markets. As more wind generation is installed to the system, market prices tend to get negatively correlated with wind generation: this leads to lower revenue when generation is high. Co-location of power generation and P2X could provide solutions for maximising market revenue, e.g., by operating the P2X when electricity prices are low or even zero. Meteorological reanalysis data are used in wind generation variability modelling [23,24]. Inclusion of stochastic simulation, as applied, e.g., in the CorRES software [25], allows accurate modelling of also the high-frequency variability.

## 3.2 OFFSHORE POWER TRANSMISSION INFRASTRUCTURE

Bornholm can act as an onshore energy hub, collecting and evacuating the offshore wind energy installed in the area around it directly to the Greater Copenhagen area on Zealand, by building transmission capacity between Bornholm and Zealand. At the same time, Bornholm's proximity to Poland enables the construction of a connection from the island to Poland, establishing an interconnection between Denmark and Poland. The interconnector, defined as a direct link, is included in the TYNDP 2018 [26]. Currently, the only connection of Bornholm is to Sweden via a 60 kV AC 60 MW submarine cable. The distance between Bornholm and Zealand is around 150 km, which makes the HVDC transmission technology the preferred choice.

If the HVDC transmission is planned only for evacuating the offshore wind produced around Bornholm, then a standard point-to-point interconnector will be required. This is considered a mature technology, with several links operating already around the world and the Northern Seas.

The main drivers for choosing the detailed technical configuration are the technology limits, i.e. submarine cables current limit and onshore AC network operating constraints such as the maximum loss of infeed, which today is 600 MW. For a 2 GW offshore wind installed capacity, none of the constraints is very hard to overcome. Detailed investigations performed in the PROMOTioN project indicate that a 2 GW, 320 kV HVDC transmission between Bornholm and Zealand will have a CAPEX of around 290 k€/MW. When considering also an interconnector to Poland, the technical configuration will be a DC hub (multi-terminal DC grid) in Bornholm. This configuration will allow for more efficient use of the transmission capacity. If a larger loss of in-feed is allowed, i.e. 900 MW instead of 600 MW, the same analysis indicates a reduction of the CAPEX of around 20% [27].

### 3.3 POSSIBLE INTEGRATION WITH P2X

Modern WTs are designed to comply with strict grid code (mainly on reactive power) set by the Transmission System Operators (TSOs), which has drastically increased the cost of design, manufacture and testing of the WTs. For WTs “dedicated” to P2X production, the need to comply with grid codes should be re-evaluated, as these WTs will not be connected to the main grid, with the potential of large cost savings. The early stage of development does not allow for numerical estimation of the cost reduction potential, but it should be considered in any future detailed analysis.

# 4 P2X – INTEGRATION WITHIN THE OFFSHORE POWER SYSTEM

## 4.1 ELECTROLYSER PLACEMENT

As previously mentioned, a 2 GW expansion of offshore power is 36-fold greater than the peak capacity of Bornholm and one-third increase of the current wind power capacity in Denmark.

P2X generation offers the possibility to absorb the surplus power, convert it to chemicals that can be stored for a longer period, and be used to decarbonise non-electrical sectors, such as transport. Figure 5 shows an example of how the P2X technologies can be used to absorb the power peaks ("peak-shaving") of the OWPP.

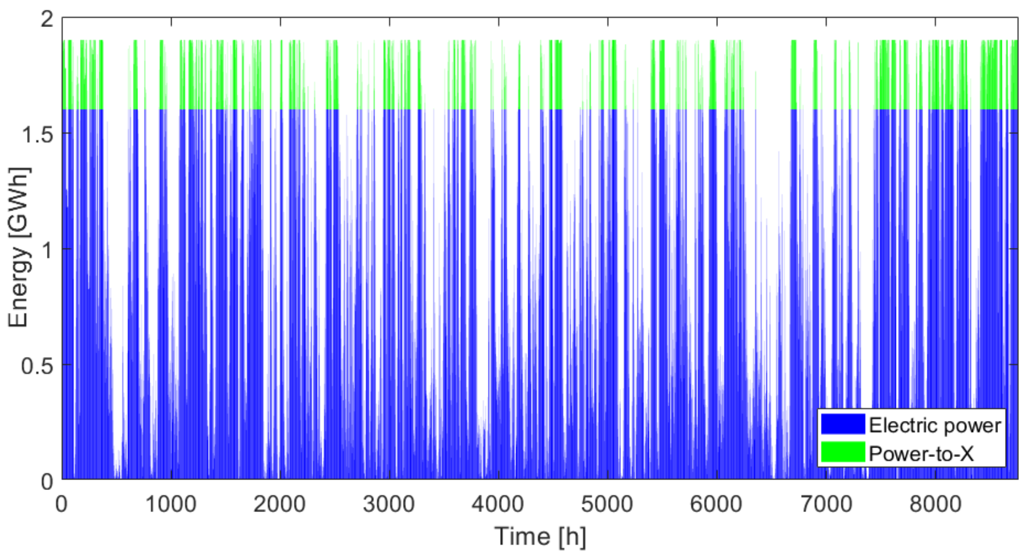


Figure 5. Example of an hourly power profile of a 2 GW OWPP, with a representative P2X facility used to shaved the power peaks. In green, the hourly electricity absorbed by the electrolyser system. In blue, the electricity delivered onshore.

The placement of the electrolyser is key to determine the $H_2$ infrastructure and possible synergies with the offshore power system and connection to the shore. The three alternative placements for the electrolyser initially introduced are described as follows.

i. In-turbine electrolyser: the electrolyser is placed inside the tower of the WT. A pipeline connects the WTs on the same AC cable array. The pipelines converge in one single pipeline at the level of the offshore substation and then the $H_2$ is transmitted to shore.
ii. Electrolyser in Bornholm: the power of the OWPP is fully transmitted to Bornholm and an electrolyser is placed in the proximity of the HVDC substation. The $H_2$ can be further compressed and transferred to Copenhagen via a pipeline.
iii. Electrolyser in Copenhagen: the power from the OWPP is transmitted to Bornholm, where an HVDC substation is placed, and then transmitted to Copenhagen through an HVDC transmission line and then converted there into $H_2$.

An upstream placement of the electrolyser would increase the CF of the downstream power infrastructure transmitting the remaining power, not converted into $H_2$. Therefore, in the case of placing the electrolyser in-turbine, the inter-array grid inside the OWPP, the export cable from the OWPP to Bornholm, and the HVDC transmission from Bornholm to Copenhagen would increase its CFs, thus reducing the cost per unit of electricity delivered onshore. In the case of the placement in Bornholm, an increase of the CF would be registered only for the HVDC line. Moreover, an upstream placement would allow the electrolyser to access to electricity with lower production costs. For instance, the cost of production of the electricity of the OWPP transmitted in Bornholm would be lower than the cost of the electricity of the OWPP transmitted to Copenhagen, because not including the HVDC transmission. Therefore, if the electrolyser is assumed (i) to be connected only to the OWPP and not to the public grid, and (ii) to internalise the cost of the electricity consumed, the more upstream the lower would be the cost of the electricity consumed.

Even if a pipeline for transferring $H_2$ would cost less than a cable used for transmitting the equivalent amount of electricity absorbed by the electrolyser, the electrolyser is a relatively expensive piece of equipment (for a 10 MW electrolyser the cost is estimated to be ca. 600 €/kW of power input [28]). Moreover, its energy $H_2$ output is 63-70% [29] of the electrical input.

The size of the electrolyser would also impact on the economies of scale, significant for ~10 MW scale, but weaker for ~100 MW [30]. Therefore, the larger the electrolyser the lower the cost per unit of power. Moreover, the larger the electrolyser used to absorb the power peaks, the higher the number of hours of operations over its lifetime. In other words, more energy produced per unit of capacity installed.

Regarding the alternative placements, also the footprint of the electrolyser would play a role. An alkaline electrolyser would occupy 0.095 $m^2$ per kW of input electricity [29] (e.g. an NBA basketball court of 28.7 m x 15.2 m would contain an electrolyser of 4.6 MW). However, a proton-exchange membrane electrolyser would require half of the area, but a higher water purity. More compact designs would need to be envisioned, especially in the case of the in-turbine placement, while for the other placements on-land the space limitation might be less strict.

## 4.2 PRELIMINARY $H_2$ COST ESTIMATION

A preliminary cost analysis has been performed, to evaluate the cost of the $H_2$ produced and to compare the three possible placements.

A representative hourly power profile has been used to model the large-scale offshore wind generation in the Baltic Sea (near Bornholm). Wake losses are assumed to be low/modest. Availability losses and other non-wake losses are assumed 5% of the power.

The OWPP is assumed to consist of large offshore WTs (10 MW) [31], combined in arrays of 8 WTs. An export cable of 20 km is assumed from the OWPP to Bornholm, while the HVDC line from Bornholm to Copenhagen is assumed to be 150 km long. Alkaline electrolyser (AEL) is chosen as reference technology for the conversion of power to $H_2$ in this analysis, as it is a more mature technology compared to the proton exchange membrane (PEMEL) and solid-oxide electrolyser (SOEL), and it would require water less pure than it would be required by a PEMEL.

In this model the size of the electrolyser is calculated from 0 to 1.9 GW (0.1 GW is assumed to be lost as previously mentioned) for the three placements, the complementary part of the power is assumed to be delivered to Copenhagen. In the calculation of the cost of $H_2$ infrastructure electrolyser, compressors, desalination units and pipelines are included.

Figure 6 shows the levelised cost of the $H_2$ (LCOH) produced considering the three alternative placements, and scaling the size the electrolyser total installed capacity from 100 MW to 2 GW (full $H_2$ conversion of the power). The effects of the economies of scale are significant in the in-turbine case. For instance, a total installed capacity of 100 MW means having a 500 kW electrolyser in each WT, compared to a single 100 MW electrolyser in the other two scenarios. Furthermore, considering a minimum of 10 cm diameter [32], for small installed capacities the pipelines are oversized in proportion to the volume of $H_2$ transmitted, resulting in high LCOH. The results show that the production of $H_2$ in Bornholm results also more cost-efficient than the placement in Copenhagen because of the cost of the lower cost of the electricity consumed by the electrolyser, which does not include the cost and the energy losses of the HVDC transmission.

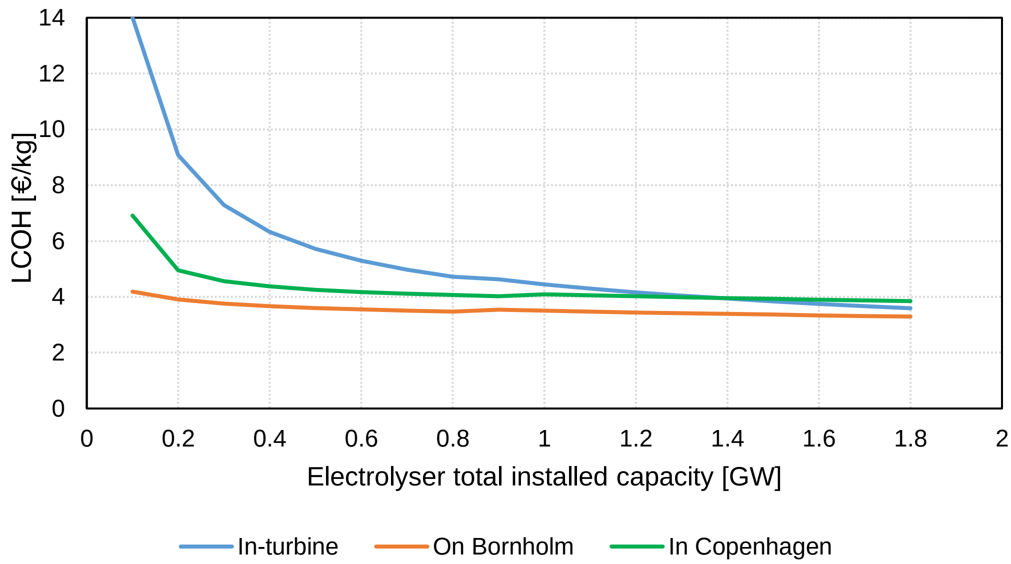


Figure 6. Levelised cost of the $H_2$ (LCOH) variation with the electrolyser total installed capacity along with a 2 GW OWPP by type of placement.

Figure 7 shows the results in case it is assumed that for the in-turbine placement, the $H_2$ is transmitted in a cable able to transfer both electricity and $H_2$ (no cost values are available for this type of technology, in an optimistic case the cost of the $H_2$ pipeline would be avoided and an increase in the cost of the design of the combined transmission would be accounted, e.g. 2%). This configuration would result in a significant cost reduction compared to the separated transmission of power and $H_2$, due to a reduction of the installation costs (two installation costs in the case of parallel transmission and one installation cost in the case of a combined transmission). However, this technology is not ready today.

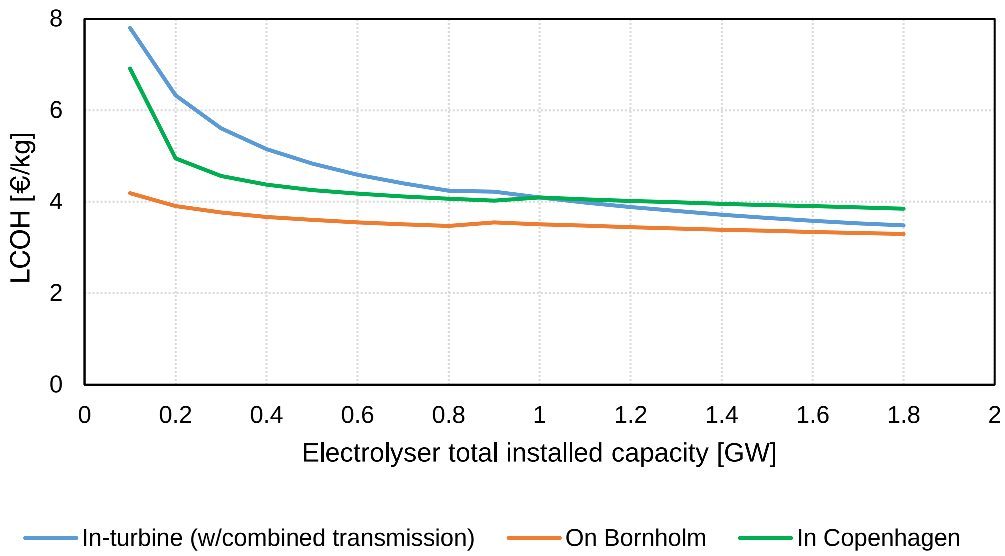


Figure 7. Levelised cost of the $H_2$ (LCOH) variation with the electrolyser total installed capacity along with a 2 GW OWPP by type of placement if a combined transmission is assumed in the in-turbine configuration.

Figure 8 shows the results in the case the $H_2$ produced in Bornholm is then transferred to Copenhagen via a pipeline. The cost of the $H_2$ produced in Bornholm and transferred to Copenhagen is comparable to the cost of having an electrolyser in Copenhagen. However, the cost of the $H_2$ in Bornholm would be the same as in Figure 7.

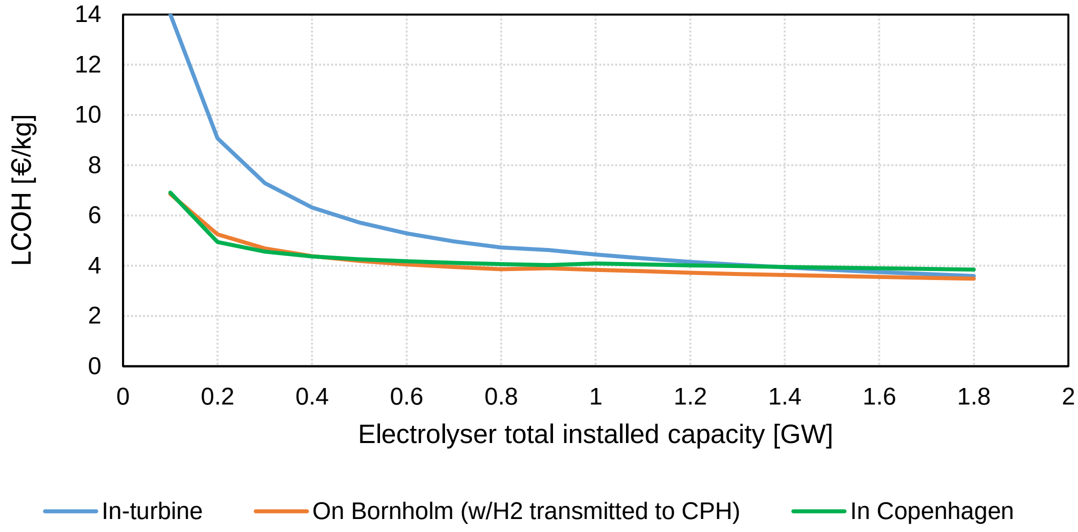


Figure 8. Levelised cost of the $H_2$ (LCOH) variation with the electrolyser total installed capacity along with a 2 GW OWPP by type of placement if the H2 produced in Bornholm is then to be transferred to Copenhagen.

These preliminary results show that $H_2$ produced from a 2 GW OWPP can have a cost from 3 to 4 €/kg from large to small capacities of the electrolyser, if produced in Bornholm. This can be delivered to Copenhagen via a pipeline with a cost from 3.5 to 7 €/kg. However, a dedicated pipeline is only beneficial if the production of $H_2$ is sufficiently high.

However, it is important to mention that current bulk production of $H_2$ is generated from steam reforming of natural gas, grey $H_2$, and its cost is 0.8-2.9 €/kg. With additional carbon capture, generating the so-called blue $H_2$, its cost is estimated to be 1.35-2.6 €/kg [33]. In Europe, electrolysis from renewables is estimated to produce green $H_2$ at a cost in the range of 2.8-3.6 €/kg [29].

Beyond the improvement of the singular technologies, to be competitive the $H_2$ production infrastructure needs further improvement, such as:

- access to cheap electricity (derived from cost reductions in the WT or the offshore power grids),
- integration of by-products, heat and oxygen ($O_2$),
- maximisation of the capacity factor of the electrolyser.

## 4.3 IMPACT ON THE COST OF THE ELECTRICITY DELIVERED TO COPENHAGEN

In this section, the cost of the remaining electricity, not consumed by the electrolyser in the three placements, and delivered to Copenhagen is presented.

Figure 9 shows the levelised cost of the electricity (LCOE) delivered in Copenhagen by changing the size of the electrolyser for the three different placements (e.g. if the total installed capacity of the electrolyser is 1 GW, the power delivered is 0.9 GW). If the electrolyser is placed in Copenhagen, the LCOE would be the same for any capacity installed of the electrolyser, since the offshore power infrastructure is not subjected to any change for any size of the electrolyser installed. If in Bornholm, the electrolyser could shave the peaks of the electric energy produced by the OWPP. Therefore, a reduced capacity of the HVDC transmission would be needed to transfer the remaining electricity from Bornholm to Copenhagen. By shaving the peaks, not only the capacity of the HVDC transmission is reduced, but also its CF is increased, therefore increasing the energy transferred per capacity installed. This would decrease the cost per unit of energy. If the electrolyser is placed in-turbine, also the inter-array grid and the export cable connecting the OWPP to Bornholm would have an increased CF. This latter analysis, however, does not take into account that the installation cost of the inter-array grid is dependent also on the length of the cable, so for the in-turbine configuration the cost reduction of the LCOE might be over-estimated.

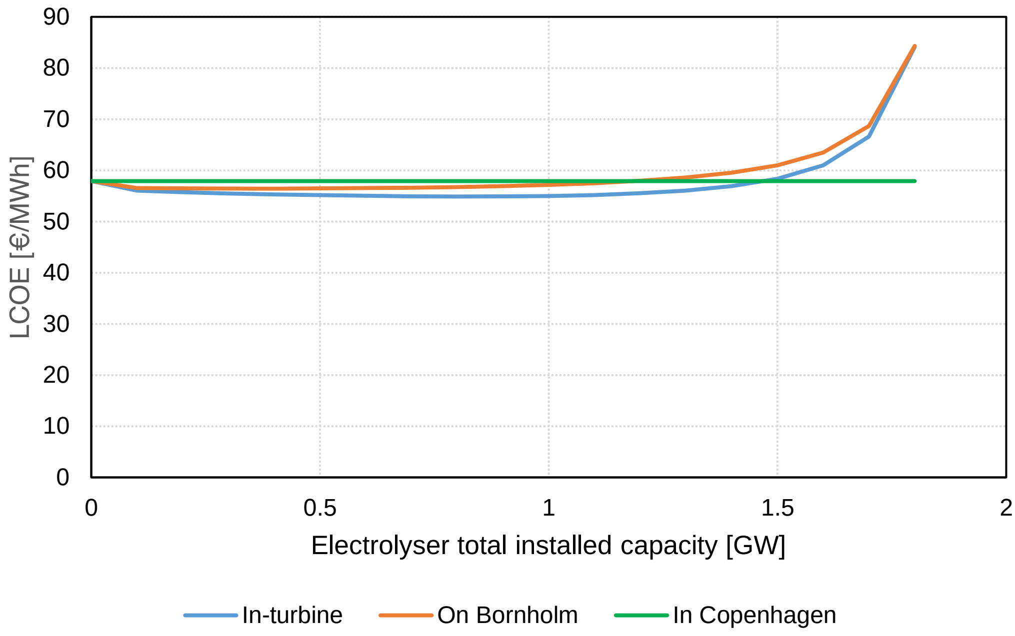


Figure 9. Levelised cost of the electricity (LCOE) variation with the electrolyser total installed capacity along with a 2 GW OWPP by type of placement. Note: for an electrolyser total installed capacity equal or greater than 1.9 GW, all the power is converted to $H_2$ (due to 5% of wake losses considered that limits the capacity to 1.9 GW).

A deeper investigation on the integration between the power and the $H_2$ infrastructures, regarding new topologies and new design of the equipment involved would undoubtedly have the double benefit of reducing the electricity and the $H_2$ cost of production.

# 5 P2X – INTEGRATION WITHIN THE ENERGY SYSTEM

## 5.1 MARITIME FUEL ALTERNATIVES

Although $H_2$ based on wind power is a zero-emission fuel, high equipment costs, lack of bunkering infrastructure, and low density, make the use of $H_2$ as fuel an extremely challenging short-term solution.

Therefore, for a more immediate application, $H_2$ needs to be converted into other chemicals such as ammonia ($NH_3$) or methanol ($CH_3OH$) [15].

Ammonia is produced by several large ammonia production plants worldwide, producing more than 170 million tonnes per year [15]. Ammonia has the potential to become a carbon- and sulphur-free energy carrier. The existing infrastructure and market ensure a solid base for its production from renewable power. The recent "Ammonfuel – an industrial view of ammonia as a marine fuel" [11] covered cost, availability, safety, technical readiness, emissions and the elimination of risks related to future environmental and climate-related regulations and requirements for the ammonia production paving the way to its use as a fuel in the medium- and long-term future. However, the maturity of ammonia is low as an alternative fuel. Moreover, toxicity and lack of a bunkering infrastructure at Rønne Havn represent a barrier for using ammonia as an alternative marine fuel on the new ferry at Rønne [15].

Methanol is the simplest alcohol with the lowest carbon content and highest $H_2$ content of any liquid fuel, it is on the top five traded commodities with an annual global production of 110 million tonnes and over 90 methanol plants. A global terminal infrastructure is in place and ready to supply the global marine industry. However, dedicated bunkering infrastructure for ships is currently limited. In the port of Gothenburg (Sweden), Stena Lines has created a dedicated area for bunkering the vessel Stena Germanica. In Germany, the first methanol infrastructure chain, from production to consumption on board the inland passenger vessel MS Innogy, was launched in August 2017 [15].

Methanol is liquid at ambient temperature and pressure, as opposed to the other renewable alternatives. Moreover, methanol fuel systems consist of mature technologies, already used in the maritime industry, which makes new-build and retrofit systems achievable for ship-owners.

Methanol can be produced via the catalytic hydrogenation of $CO_2$.

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$

A limiting factor for the production of methanol is the access to $CO_2$, whose origin has to be from sustainable biomass (e.g. from residual biomass or organic waste) or air. Renewable carbon-based fuels can already be used in the existing fleet with small modifications, as chemically identical to the fossil counterparts currently used, so a replacement can start right away. While, if aiming for ammonia, the fleet will need to be replaced, which is expected to take off shortly before 2030.

A brief comparison of chemical and physical properties of alternative fuels is presented in Appendix A – Fuel properties.

## 5.2 CARBON SOURCES IN BORNHOLM

To ensure the production of carbon-based fuels, renewable sources of carbon are necessary. The biomass in Bornholm is the main resource. Two types of biomass can be identified: (i) dry biomass, which can go through thermochemical treatment (such as combustion and gasification), and (ii) wet biomass, whose water content is too high for an efficient thermal treatment and which is biologically processed (e.g. through anaerobic digestion) [34].

In the case of Bornholm, dry biomass is combusted in combined heat and power plants. For this analysis, it is assumed that all the biomass is $CO_2$ neutral. The annual amount of biomass currently processed and the estimated amount of $CO_2$ emitted considering full combustion are shown in Table 2.

Table 2. Dry biomass currently used and estimated emissions.

| | Mass [t/y] | Estimated $CO_2$ produced [t/y] |
|---|---|---|
| Straw | 18,790 | 2,662 |

| | | |
|---|---|---|
| Chips | 58,558 | 9,092 |
| Imported chips | 19,300 | 2,997 |
| Total | 96,648 | 14,750 |

Analogously, Table 3 shows the potential wet biomass in Bornholm and its estimated $CO_2$ that can be extracted from the biogas produced.

Table 3. Wet biomass potential amount in Bornholm and estimated $CO_2$ in the biogas. See Appendix, for the assumptions

| | Mass [t/y][35] | $CH_4$ energy content [MWh] [35] | Volume $CH_4$ [$m^3$/y] | Volume $CO_2$ [$m^3$/y] | Mass $CO_2$ [t/y] |
|---|---|---|---|---|---|
| Liquid manure | 547,536 | 70,908 | 7,130,413 | 5,833,975 | 11,376 |
| Deep litter | 29,731 | 17,592 | 1,769,028 | 1,447,386 | 2,822 |
| Garden waste | 8,920 | 4,479 | 450,402 | 368,511 | 719 |
| Other | 16,758 | 8,674 | 872,246 | 713,656 | 1,392 |
| Total | 602,945 | 101,653 | 10,222,089 | 8,363,528 | 16,309 |

Considering dry biomass currently combusted and the potential wet biomass that can be digested, the theoretical annual amount of $CO_2$ is 31,423 tonnes. This amount of $CO_2$ can lead to a production of methanol up to 22,853 tonnes per annum (126,325 MWh). Details of this estimation are presented in Appendix B – CO2 potential. Moreover, it is important to notice that this is the upper limit of available $CO_2$, the carbon capture technology would be able to capture only a part of it.

## 5.3 METHANOL PRODUCTION SYSTEM INTEGRATION

In this section, the possibility of producing methanol using the $H_2$ from electrolysis and available $CO_2$ sources is investigated, considering also the integration of the $H_2$ infrastructure with the existing energy system, thus including the connection to the power grid, and the possibility to buy electricity from the grid and sell the electrolysis by-products: heat and $O_2$. The system is designed to satisfy Rønne Havn energy demand of 237,000 MWh the ferries with base in Rønne Havn, equivalent to 43 kt of methanol per year. Figure 10 presents the business model considered for this part of the study.

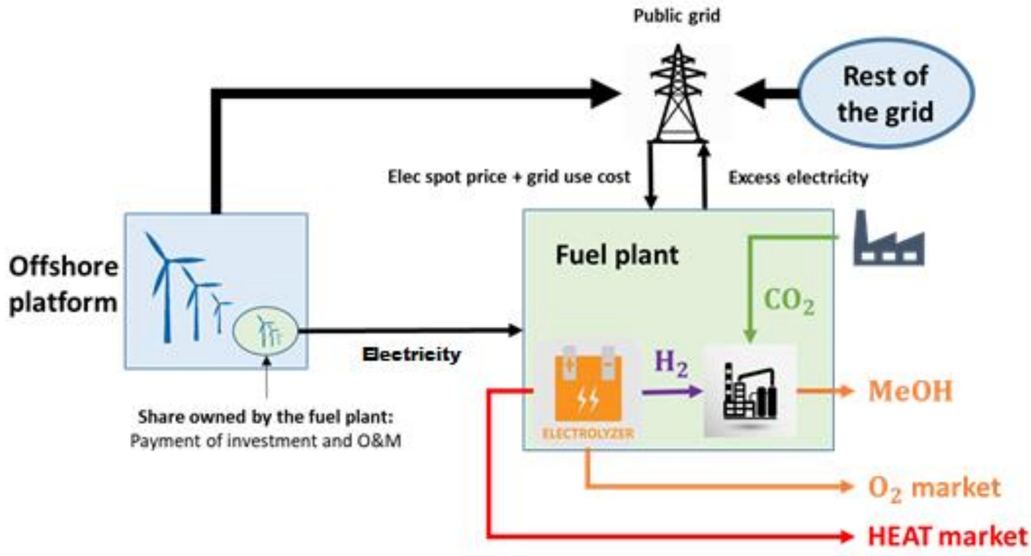


Figure 10. Schematic representation of the fuel production plant business model.

The business model considers that the fuel production plant owns a share of the offshore wind park. When available, the electricity coming from that share is used. To own a share of the wind park, the owner of the fuel production plant pays the investment, the O&M cost and the grid connection corresponding to the capacity acquired. Aside from that, the plant can buy electricity from the public grid at normal price. If the system produces more electricity than needed in some hours, it is possible to inject this excess electricity to the grid. The electricity is injected into the grid.

When onshore, the plant interacts with the electrical public grid according to two different policies:

i. Full priority: the electricity from the grid is always available in any quantity and it is always possible to inject electricity surplus. The price of electricity is determined according to the electricity spot price plus the distribution, transmission and taxes cost (16.65 €/MWh). When the price of the grid electricity is lower than the cost of production of the electricity from the OWPP, the electrolyser consumes the electricity from the grid and the power from the OWPP is injected into the grid.

ii. Limited access: electricity from the public grid can only be used when there is a production higher than the demand. Reversely, it is not possible to inject electricity when the global demand is already higher than global production (import of electricity). In Copenhagen, the grid availability is estimated using current electricity import/export from Nordpool DK2. In Bornholm, the grid availability is determined on import/export data specific to Bornholm. In both cases, the electricity produced by the 2 GW offshore farm is added to the current global production without increasing the electricity demand. This is an approximation, and further investigation is needed to detail the grid availability profile in an interconnected European context.

The following considerations can be made:

i. Electrolyser in-turbine (Figure 11): this configuration is assumed to be without access to the public grid, and no access to heat and $O_2$ demands. A large $H_2$ storage system is necessary to meet the minimum load requirement of the methanol plant. For this study, the $H_2$ is assumed to be stored in-land inside tanks pressurised at 800 bars.

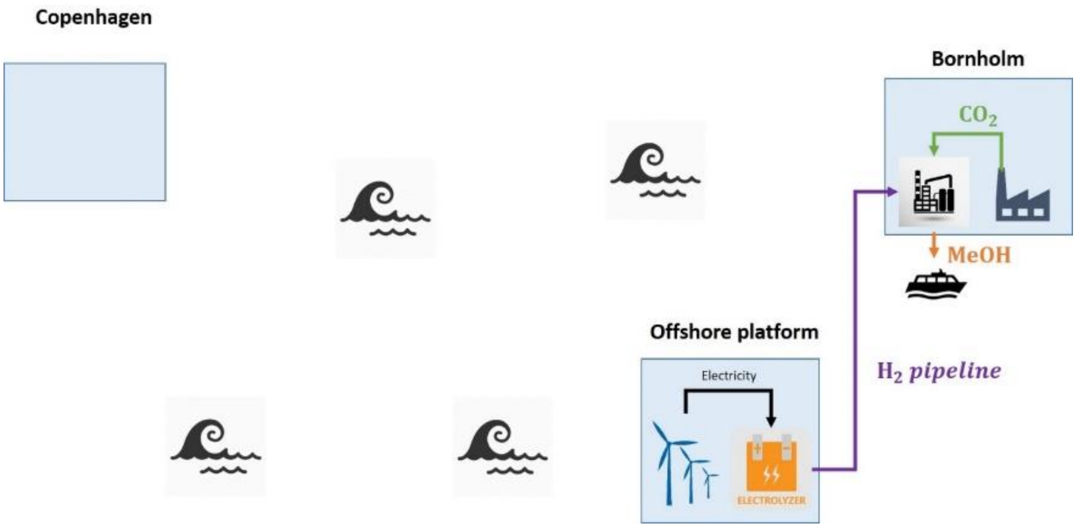


Figure 11. Schematic representation of scenario 1: in-turbine electrolysis integrated with methanol production in Bornholm.

ii. Electrolyser in Bornholm (Figure 12): the electrolyser is assumed to be connected to the public grid on top of the connection with the OWPP. It is possible to sell excess heat and $O_2$.

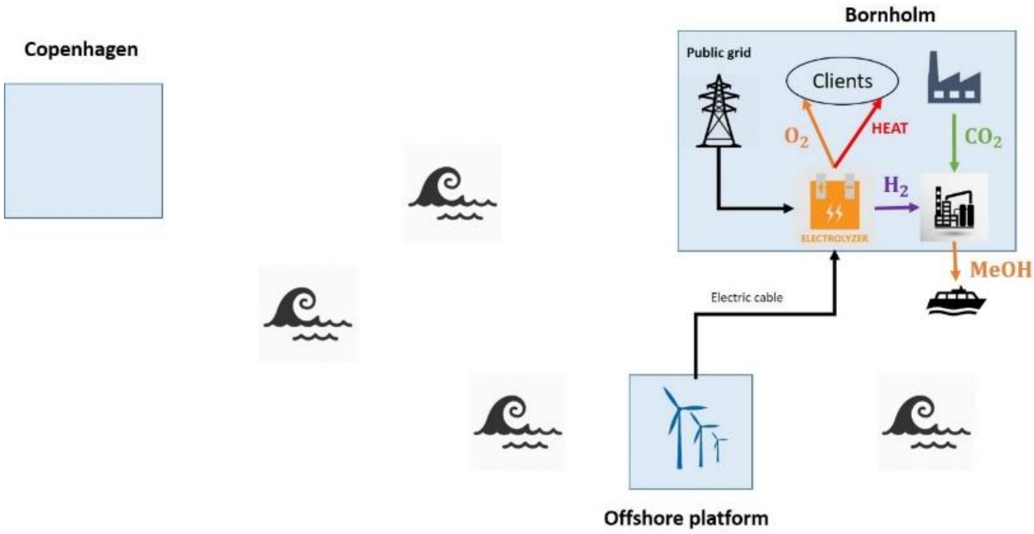


Figure 12. Schematic representation of scenario 2: electrolysis and methanol plant in Bornholm.

iii. Electrolyser in Copenhagen (Figure 13): this scenario implies high grid connection cost between Bornholm and Copenhagen, which the fuel producer would need to cover to access to the electricity from OWPP. It is possible to sell excess heat and $O_2$.

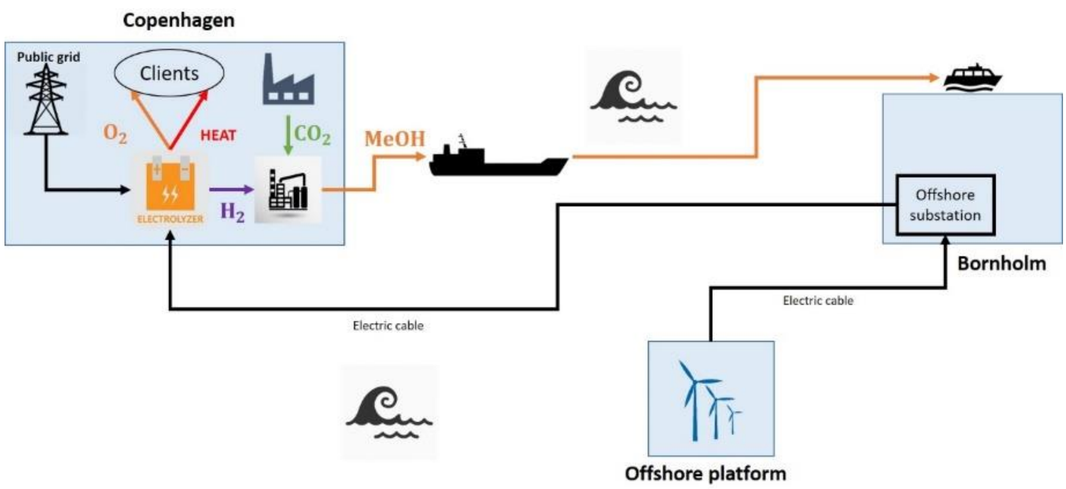


Figure 13. Schematic representation of scenario 3: electrolyser and methanol plant in Copenhagen.

Figure 14 shows the detailed fuel production system under study. Each unit of the energy system is characterised by their technical specifications (efficiencies, flexibility ranges or electrical consumption) and economics parameters (annualised investment cost, operation and maintenance, etc.). The different units optimally interact with each other to reach the lowest fuel production cost.

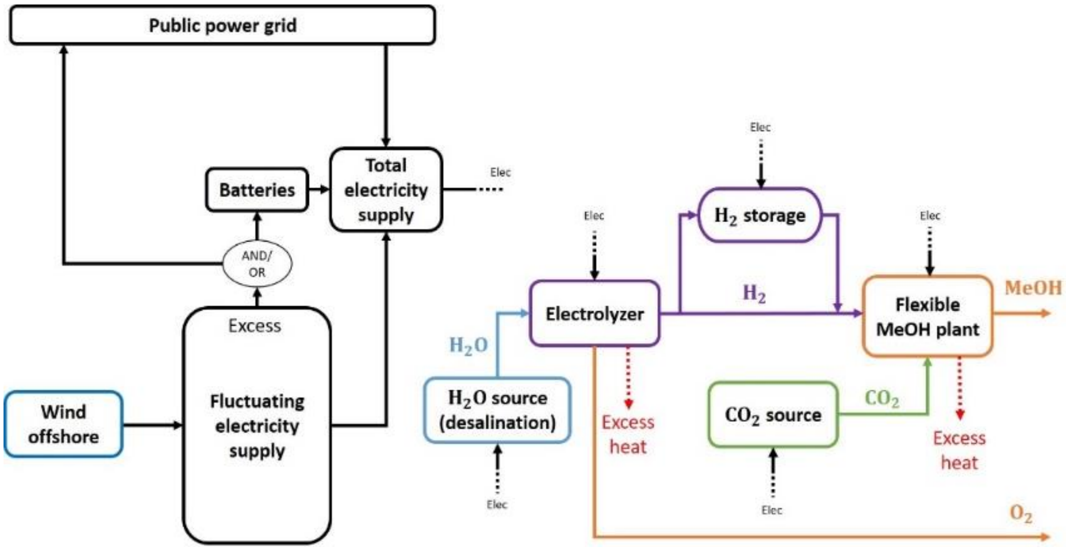


Figure 14. Schematic representation of the energy/mass exchanges in the model.

As presented in Figure 15, the model uses techno-economic data and power profiles, which are publicly available as input and aims to minimise the total fuel production cost. Solving the model determines the installed capacities, the hourly mass/energy flows and the trade of by-products/raw materials that lead to the lowest fuel production cost given the input data set.

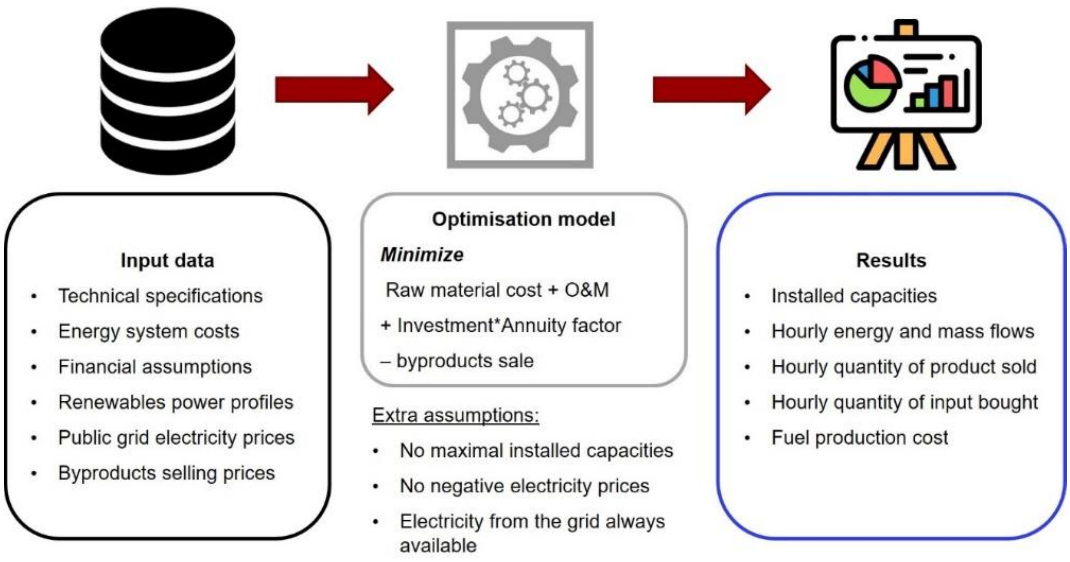

Figure 15. Optimisation model description.

The main data and assumptions used in the study are summarised in Table 4. More details about the data origin are available in the appendixes.

Table 4. Techno-economics data set. RH refers to data made available from Rønne Havn

| | $H_2$ Offshore | $H_2$ Bornholm | $H_2$ Copenhagen | Ref. |
|---|---|---|---|---|
| MeOH plant | Demand: 43 kt/y<br>Cost: 450 €/ (t/y)<br>Load flexibility: [40-100%] | | | RH<br>[36]<br>[37] |
| $CO_2$ | Availability:31kt/y<br>Recovery: 90 %<br>Cost: 40 €/ t $CO_2$<br>Demand: 1.46 $kg_{CO_2}$ / $kg_{MeOH}$ | | | Estimated<br>[37]<br>[36] |
| ELECTROLYZER | Cost: 756 €/kW<br>Efficiency: 50.5 $kWh/kg_{H_2}$<br>Heat: 6 $kWh_{heat}/kg_{H_2}$<br>Load flexibility: [0-100 %] | Cost: 600 €/kW<br>Efficiency: 50.5 $kWh/kg_{H_2}$<br>Heat: 6 $kWh_{heat}/kg_{H_2}$<br>Load flexibility: [0-100 %] | | [38]<br>[39]<br>[38]<br>[39] |
| $H_2$ storage | Cost: 900 €$/kg_{H_2}$ | | | [40] |
| H2 PIPELINE | Distance: 20 km<br>Cost: 766 €$/(kg_{H_2}/h)$ + 6.49 M€ | No $H_2$ pipeline | | Estimated<br>[32] |
| Offshore | Cost: 750 €/kW | Cost: 2170 €/kW[1] plus 40.6 M€[3] | Cost: 2610 €/kW[2] plus 40.6 M€[3] | [41]<br>[42] |
| DISTRICT HEATING | No sale | Sale price: 28.8 €/MWh | | [43] |
| $O_2$ | No sale | Demand[4]: 19 kt<br>Sale price: 100€/t | Sale price: 100€/t | [13]<br>[44] |
| Public grid | Not connected | Spot price (NordPool 2018) + 16.65€/MWh | | [45] |
| Finance | Discount rate: 5% discount rate<br>Loan share: 50% loan share<br>Loan interest: 2% loan interest | | | Assumed |

[1] Including grid connection and export cable; [2] Including grid connection, export cable and HVDC line; [3]Installation costs export cable; [4]Demand of oxygen in wastewater treatment plants, hospital, and industries in Rønne.

## 5.4 PRELIMINARY METHANOL COST ESTIMATION

Given the input data, the algorithm determines the optimal installed capacities for each scenario. The hourly mass and electricity fluxes are optimised to have the lowest system cost. However, the system is optimised assuming perfect foresight (renewable power production is known a year in advance). Therefore, global system costs, including storage capacities might be underestimated compared to a real case system designed more robustly.

Figure 16 shows how the optimal fuel production system in Bornholm with full access to the grid.

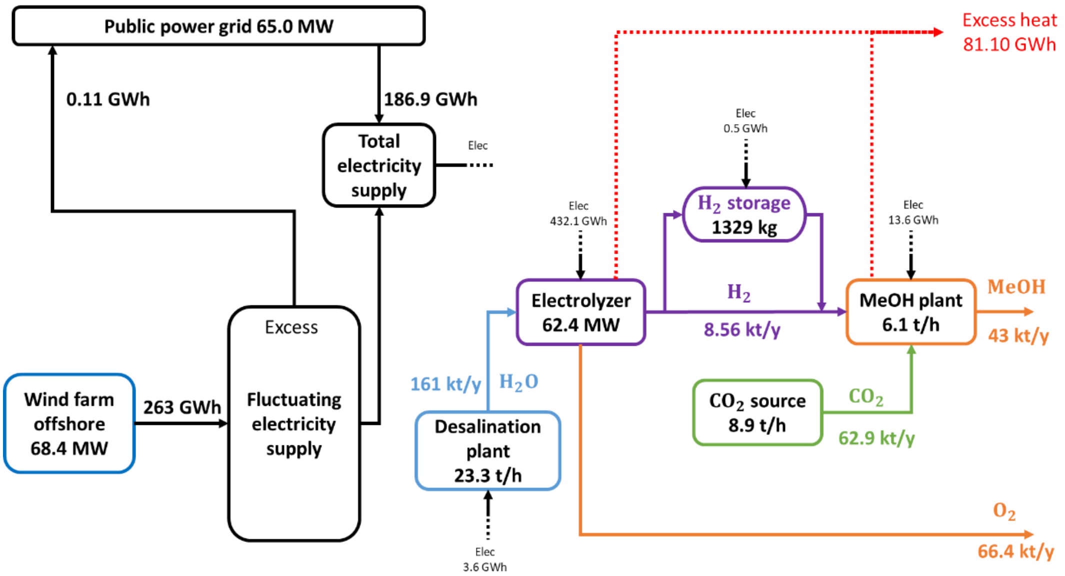


Figure 16. Energy system mass and energy balances for fuel production in Bornholm.

One of the major results shows that around 63,000 t a year of $CO_2$ would be needed to fulfil the current fuel demand of Rønne Havn. However the maximum theoretical amount of $CO_2$ available in Bornholm is about 31,000 t, so, at most, only half of the methanol demand of Rønne Havn could be produced in Bornholm with the considered carbon sources.

Figure 17 shows the fuel production cost according to the electrolyser location and grid access. In this graph, by-products are not sold. The scenarios "full-grid" assume that electricity from the grid is always available in any quantity. The scenarios "grid-limited" assume that is not possible to use electricity from the grid when that one is already imported from somewhere else. Costs are compared to the current European market price for fossil methanol. According to the brief literature review from [37], common ranges for green methanol are between 260 €/t and 1060€/t with an average cost of around 600 €/t. The values estimated for this study lay within the upper part of this range.

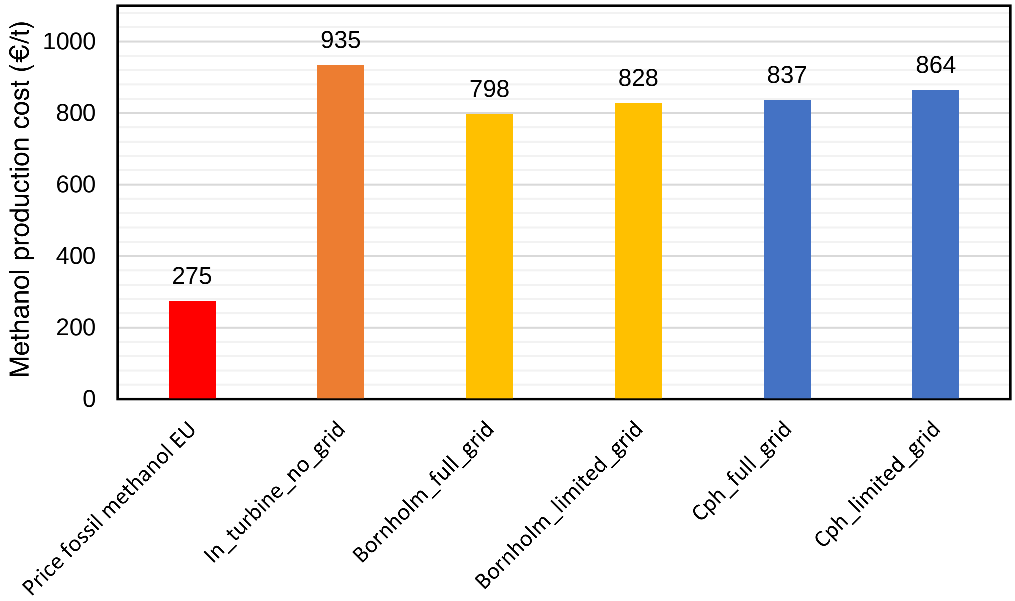


Figure 17. Fuel production cost without by-products sale and depending on grid access.

If the access to the grid is limited, the fuel production cost increases due to the need of additional storage such as batteries or a larger $H_2$ tank, and to expand the elelctrolyser capacity, to keep the methanol production above 40% of its nominal load. In Bornholm, the optimal electrolyser size is 62.4 MW with the full access to the grid and 64.4 MW with limited access.

The fuel production cost is higher if the electrolyser is placed in Copenhagen rather than in Bornholm, due to the investment cost for the HVDC link from Bornholm to Copenhagen, which also pushes the fuel producers to buy more electricity from the public grid as shown in Figure 18. However, using a large electricity share from the public grid may question the methanol low carbon content, which depends on the grid energy mix. In Copenhagen, the optimal electrolyser capacity is 58.2 MW with full grid access and 60.5 MW with limited access.

The in-turbine scenario is penalised compared to the others due to the higher electrolyser investment cost, due to offshore installation, and mostly because of the lack of a grid connection. Therefore, without connection, the cost of the $H_2$ is driven by the storage needed to prevent methanol plant shutdowns (i.e. 120 t of $H_2$ need to be stored). Also, the electrolyser also needs to be oversized to fill the storage tanks, increasing the initial investment costs. In the in-turbine scenario, the optimal total installed capacities for the electrolyser is about 106.9 MW, nearly double the installed capacity of grid-connected scenarios. With a fully flexible methanol plant, able to shut down frequently without damage, system costs would decrease significantly.

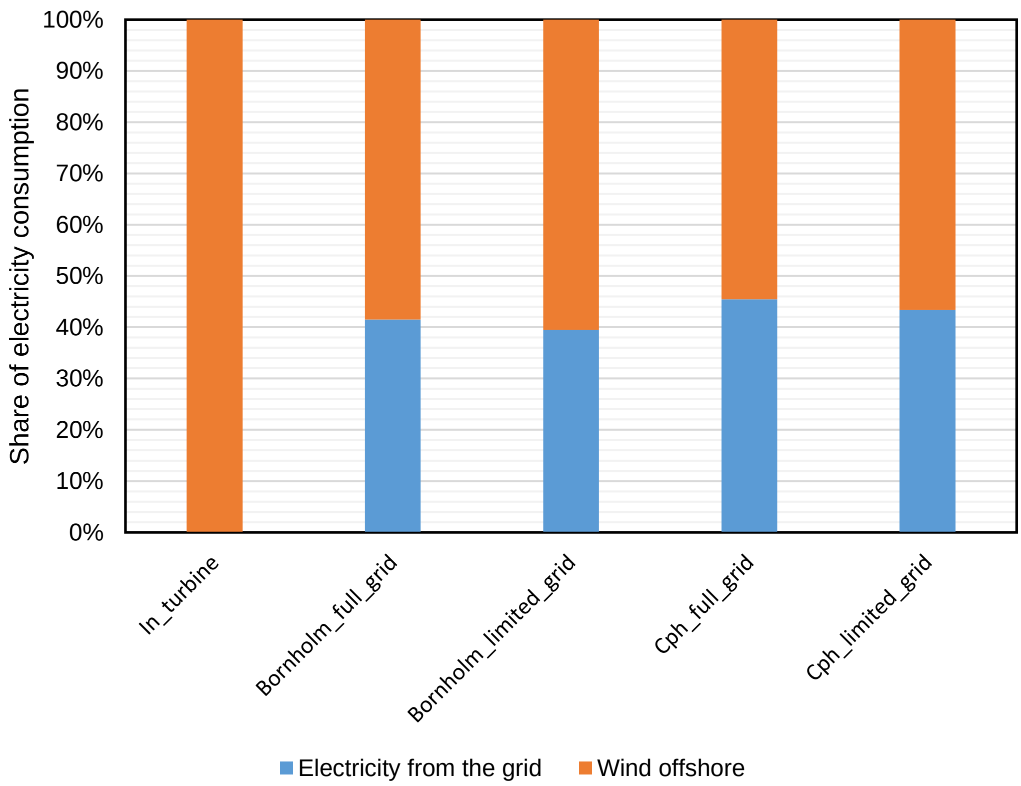


Figure 18. Share of electricity production.

In Figure 19, the methanol production cost is also evaluated according to the quantity of sold by-products. In all cases, the public grid is always available and the $CO_2$ resource is unlimited.

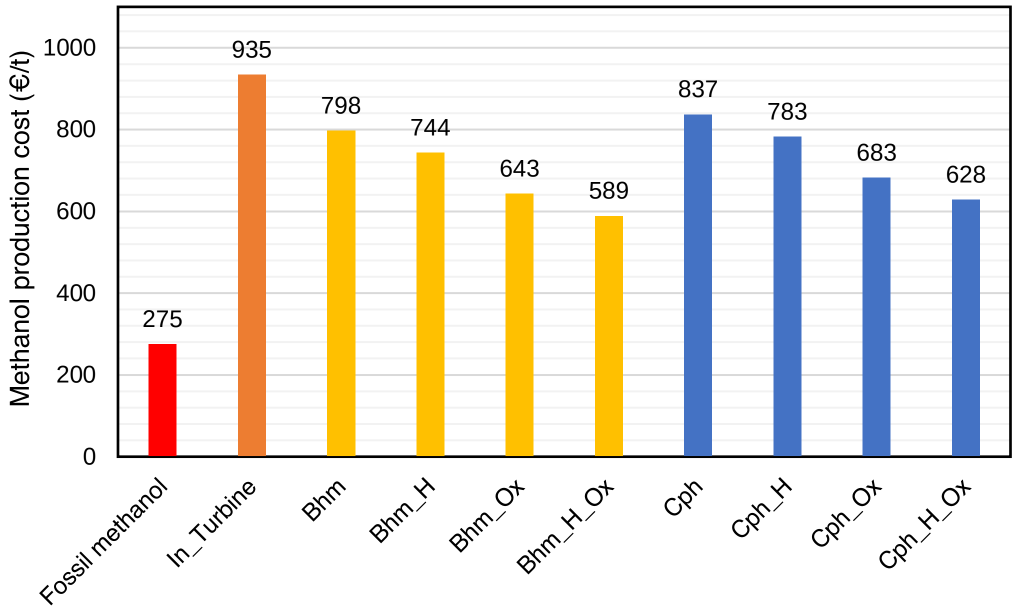


Figure 19. Fuel production cost depending on location and by-products sale. Bhm: Bornholm without by-product sale; Cph: Copenhagen without by-products sale; H: 100% of the heat and 0% of the oxygen is sold; Ox: 100 % of the oxygen and 0 % of the heat is sold; H_Ox: 100% of heat and oxygen are sold.

The offshore scenario is even more penalised compared to the two others due to the non-possibility of by-products sale, on top of the large $H_2$ storage cost implied by the lack of grid connection. The lowest production cost is found when the methanol is produced in Bornholm with all the by-products sold and reaches 589 €/t.

However, in Bornholm, the $CO_2$ availability is a key limiting factor and less than half of the demand for ferries can be produced in Bornholm. It has also been assumed that all $O_2$ and heat could be sold in Bornholm, which is optimistic. Therefore, the fuel production cost with limited $CO_2$ resources in Bornholm and limited $O_2$ demand is shown in Figure 20. The theoretical $CO_2$ resources have been estimated to be 31.4 kt per year. Assuming a $CO_2$ capture around 90%, this would represent a methanol production of approximately 19 kt/y so a bit less than half of the methanol port demand. With a 19kt/y methanol production, around 29.3 kt/y of $O_2$ per year are produced. Assuming that all the plants using air in Rønne would use pure $O_2$ instead, the $O_2$ demand would, in the best case, reach 19 kt per year which is called “real oxygen demand” (_ROx). An electrolyser capacity of 27.6 MW is needed to produce the 19 kt/y of methanol.

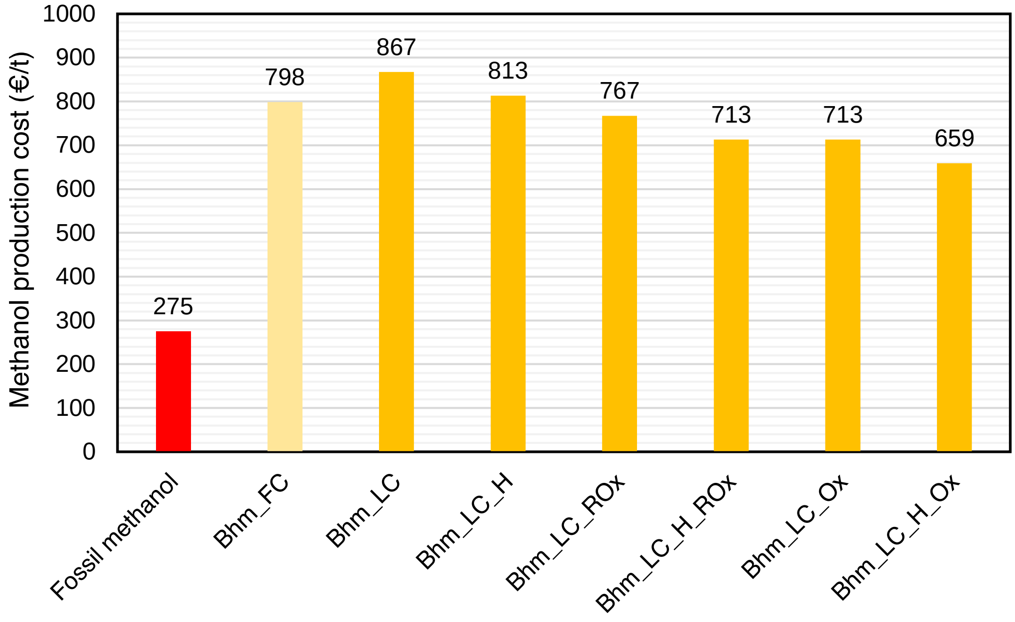


Figure 20. Sensitivity analysis on by-products sale in Bornholm with a limited amount of $CO_2$ available. FC: Full $CO_2$ (unlimited); LC: Limited $CO_2$; ROx: Real demand of oxygen; Other subscripts identical to Figure 19.

The production costs are slightly higher compared to the full $CO_2$ availability case (Bhm_FC). This is due to the cost of the installation of the export cable that does not depend on the offshore capacity installed: although the decreased methanol production, that cost is unchanged, resulting in a higher cost per unit of energy produced.

Compared to the case without selling by-products (Bhm_LC), the methanol production cost is reduced up to 24%, in the case in which all the heat and $O_2$ produced are sold. However, selling all the $O_2$ is not realistic in Bornholm, considering the potential demand. Selling the amount of $O_2$ to satisfy the real $O_2$ demand, in combination with excess heat, reduces the methanol production cost by up to 18%, and reach 713 €/t.

Figure 21 indicates the main system cost drivers, as annualised costs, for each unit of the model depending on the scenario.

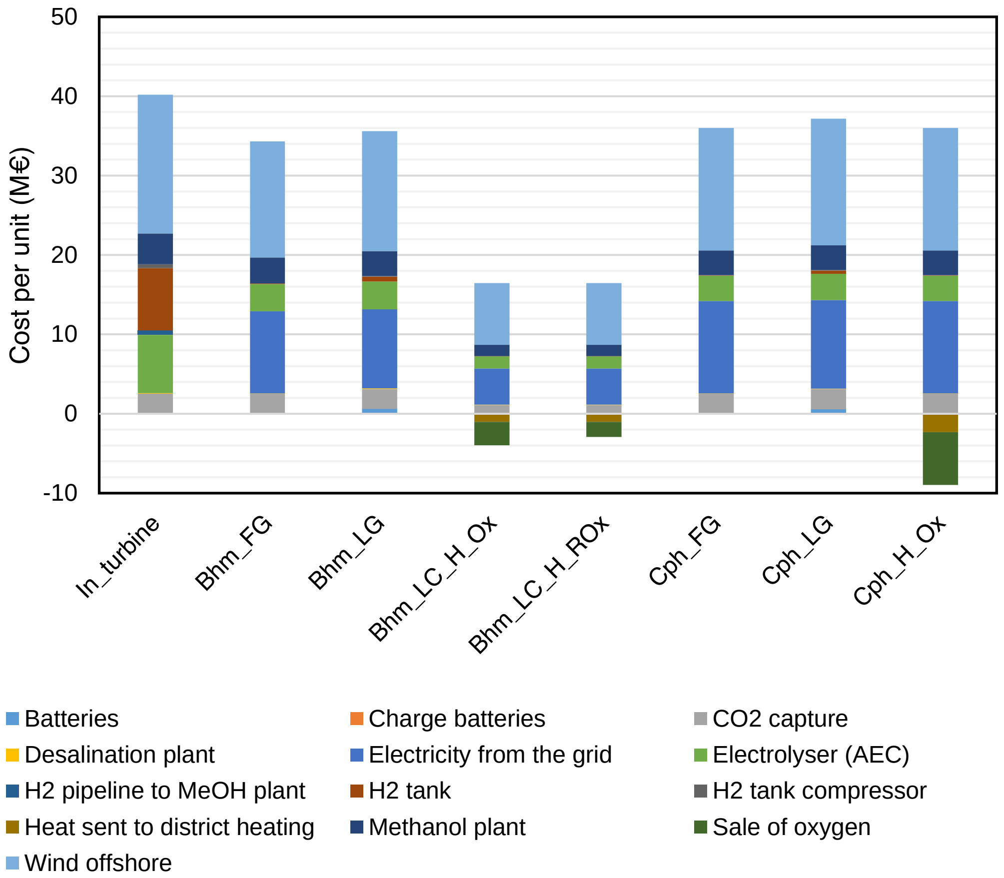


Figure 21. Annualised cost per unit depending on the scenarios

The main cost driver is always the OWPP and the related offshore power infrastructure, which is higher in the case in which the electrolyser is placed in Copenhagen rather than in Bornholm. The second highest expenditure is the electricity bought from the grid to power the electrolyser to keep a minimal methanol production, during those hours in which the OWPP does not produce electricity. Buying electricity from the grid remains cheaper than investing in large $H_2$ storage, which explains why the in-turbine scenario presents the worst results. When access to the public grid is limited, it is also necessary to invest in a small battery park and $H_2$ tank.

Supplementing with investments in solar PV and onshore wind to generate the electricity, would have reduced the fuel production cost in all cases. Producing the $H_2$ offshore without selling by-products is the most expensive solution (935€/t of methanol). Transporting and selling the $O_2$ to Bornholm via pipeline could be investigated to improve the business case.

The most cost-efficient solution is to produce $H_2$ and methanol in Bornholm with full access to the grid, unlimited $CO_2$ and the possibility to sell all the by-products. In that case, the methanol production cost is 589 €/t. However, this configuration obstructed by the limited $CO_2$ sources and $O_2$ demand. With a methanol plant size of 19 kt/y more adapted to the potential $CO_2$ resources in Bornholm, a maximal $O_2$ demand of 19 kt/y and the possibility to sell all the heat, the production cost reaches 713 €/t. However, although the limited amount of $CO_2$ available, part of the $H_2$ can be converted to methanol in Bornholm and the rest can be transferred elsewhere.

A detailed study of the $O_2$ and heat market in Copenhagen and $CO_2$ availability would give a better idea about the economic interest to locate the electrolyser and the methanol plant there. If it is possible to sell all the heat and $O_2$, production cost in Copenhagen could reach 628 €/t.

# 6 CONCLUSIONS

## 6.1 KEY FINDINGS

Offshore wind power future expansion in the Baltic Sea, in conjunction with planned interconnections and the necessity to store/convert surplus power puts Bornholm in position to be the first natural energy hub. Bornholm can be, not only the centre for electrical equipment such as substations, and nodes of connections between countries, but also centre for P2X production from offshore wind power.

This preliminary investigation indicates that placing an electrolyser in Bornholm would lead to a cost of production of the $H_2$ lower than it would be placing an electrolyser in Copenhagen, however, with limited access to $CO_2$ and $O_2$ and heat consumers. The amount of $CO_2$ available from the current CHP plants burning biomass, and from the biogas of all the potential wet feedstocks that can be digested is insufficient to satisfy Rønne Havn demand for renewable fuels.

Table 5 shows a summary of the pros and cons of placing the electrolyser in the three possible main locations: in-turbine, in Bornholm, on Copenhagen.

Table 5. Summary of the pros and cons of the possible electrolyser placements.

| Location | Pros | Cons |
|---|---|---|
| In-turbine | ○ Simplification of OWPP design. | ○ Limited space available.<br>○ Desalination unit needed.<br>○ Multiple small units with higher costs.<br>○ Articulated design of the $H_2$ infrastructure.<br>○ Inflammable chemical inside the wind turbine. |
| In Bornholm | ○ Size reduction of the HVDC transmission to Copenhagen.<br>○ Possibility to use heat to satisfy the heat demand.<br>○ Possibility to sell the $O_2$.<br>○ Possibility to sell the heat. | ○ Limited $H_2$ demand.<br>○ Limited $CO_2$ sources.<br>○ Limited heat demand.<br>○ Limited $O_2$ demand. |

| | | |
|---|---|---|
| | ○ Possibility to access to renewable $CO_2$ sources.<br>○ Simple design of the $H_2$ infrastructure. | |
| In Copenhagen | ○ Possibility to sell the heat.<br>○ Possibility to sell the $O_2$.<br>○ Possibility to access to renewable $CO_2$ sources.<br>○ Simple design of the H2 infrastructure.<br>○ Flexibility of having the electricity produced by the OWPP in a large AC network. | ○ No impact on the cost of the electricity delivered onshore. |

For an immediate decarbonisation of the maritime transport sector, the conversion of $H_2$ to a drop-in fuel is necessary, therefore methanol is considered as the most promising alternative. $CO_2$ from biomass combustion in CHP plants and potential biogas production is not sufficient to produce the amount of methanol needed by ferries to satisfy its demand, covered only around half of the demand. The lowest cost of production for methanol is reached at 589 €per tonne when the electrolyser is located in Bornholm with access to the public grid, and no $CO_2$ limitations and if all the by-products (heat and $O_2$) are sold.

An electrolyser in Copenhagen would produce $H_2$ at a higher cost compared to an electrolyser in Bornholm, due to higher grid connection cost, which increases the cost of the electricity delivered onshore from the OWPP and consumed by the electrolyser. Therefore, in the most cost-efficient case, a large share of the electricity consumed by the electrolyser is provided by the public grid. This is due by the fact that the cost of the electricity delivered onshore from the OWPP is, for most of the time, higher than that the price of the electricity that can be bought from the grid.

However, considering the limitations in Bornholm, the business case may become more favourable in Copenhagen if $CO_2$ is available in sufficient quantity and if it is possible to sell all the by-products without restrictions.

Producing the $H_2$ offshore without the possibility to sell by-products is the most expensive solution. The possibility to extend the system flexibility increases significantly the economic potential of the offshore electrolyser.

## 6.2 LIMITATIONS AND FUTURE WORK

This investigation aimed to provide a preliminary overview of the challenges related to the placement of a P2X facility to deliver $H_2$ and methanol at the lowest cost. Environmental and societal impacts were out of the scope of this work. However, the investigation of the environmental and societal impact is necessary to evaluate the overall feasibility of the placement of a P2X facility.

Moreover, the interconnection of Bornholm with Denmark and other countries would modify the availability of the power that might be converted into fuels. Furthermore, new interconnections and the injection of a massive amount of offshore wind power would also affect the electricity market prices. This impact needs to be assessed.

## 6.3 BORNHOLM – THE P2X ISLAND?

To be able to compete in the future international market for electrofuels the costs need to be kept low. Therefore, access to plenty and cheap electricity, a stable energy system, carbon sources and synergies with local industry and heat consumers need to be in place. Without new industries utilising this surplus heat and by-products, by creating a symbiosis with the P2X plants at Bornholm, the business case will look less profitable and a P2X strategy for Bornholm should therefore include visions for future industrialisation of Bornholm.

Other than the production of $H_2$ and carbon-based fuels, such as methanol, additional scenarios can be envisioned for Bornholm's future as green fuel producer. The main visions are listed, and their impact and policy needs are discussed in Table 6. Moreover, today it is cheaper to produce fuels for shipping and aviation from biomass, therefore the electrofuel market and production will not take off without having it on the political agenda. This means, for example, supporting research projects and investment in test plant facilities and full-scale demonstration plants. On the other hand, stricter policies limiting unsustainable use of biomass is probably also needed to prevent a development down a path of mainly using biomass for future transport fuels.

Table 6. Bornholm P2X-island alternative visions.

| Main alternatives | Description | Decarbonisation potential | Policy needed | Benefits |
|---|---|---|---|---|
| AMMONIA PLANT | 2 GW of power can produce around 17 PJ liquid ammonia and 8 PJ heat, enough to cover the Danish demand for shipping fuel. However, because of the graduate fleet replacement, a bigger market has to be considered and it might be able to cover the demand for ammonia for shipping in the Baltic Sea in 2030. The market for fertiliser should be investigated to see if this could be a catalyser for ammonia production.<br>Scaling up to 10 GW offshore wind after 2030 means possible 80-90 PJ ammonia and 40 PJ heat. The export of shipping fuel is essential and Bornholm could either become an international ship fuelling station or deliver shipping fuel to the harbours in the Baltics. The amount of heat generated should be utilised in other industries if possible. | The shipping fuel produced can only replace fossil fuels in new ships designed to run on ammonia, so it will only have a small impact in 2030, but then growing from there. As a fertiliser, the green ammonia can replace production based on natural gas right away. | Support to $H_2$/ammonia plant, and Bornholm local industry and heat plan. | Low investment requirements in power connections and less transport of fuels and fertiliser, when the ammonia is produced and used in Bornholm. |
| $H_2$ BLENDED IN THE BALTIC PIPELINE | Utilising existing and planned infrastructure to abate the costs of transporting the $H_2$ produced. The $H_2$ is injected in the planned Baltic Pipe and used for fuel production in other places in Europe.<br>The production of $H_2$ will generate plenty of surplus heat for covering all district heating demand and industrial process heat in Bornholm. | Directly replaces fossil natural gas in the Baltic Pipe and thereby in the supply to Europe. | Negotiate a pipe junction on Baltic Pipe to Bornholm. Increased level of $H_2$ in the European gas grid has to be accepted. Bornholm local industry and heat plan. | Low investment requirements in power connections, decrease cost in the transportation of the green fuels as only $H_2$ is produced in Bornholm, while the carbon-based fuels can be produced in Copenhagen, near carbon sources and demand. |

| | | | | |
|---|---|---|---|---|
| $H_2$ PIPELINE TO COPENHAGEN | The $H_2$ is produced in Bornholm then transferred to Copenhagen via a dedicated pipeline. Converting the $H_2$ in Copenhagen means being close to demand centres: airport, harbour facilities for shipping away fuels and the Copenhagen district heating. There are also carbon sources from waste incineration and biomass plants. The 2 GW wind can produce around 25 PJ $H_2$ and all the heat Bornholm needs. Increasing to 10 GW wind production can reach 120 PJ of $H_2$, which means the factory in Copenhagen can produce fuels for all bunkering of ships and aeroplanes in Denmark. | Fossil aviation and shipping fuels can be replaced right away if the focus is on producing green fuels with carbon content. | The decision on green fuel plant in Copenhagen, decision on an $H_2$ pipe from Bornholm to Copenhagen area, Bornholm local industry and heat plan. | Low investment requirements in power connections, decrease in the transportation of the green fuels as only $H_2$ is produced in Bornholm while the carbon-based are produced in Copenhagen near carbon sources and demand. |
| STRENGTHEN INTERCONNECTION | The interconnectors between Bornholm to other countries are strengthened, so that the electricity produced is distributed to where the demand occurs.<br>In this way, wind power from Bornholm can be used in other countries. This vision can be seen as a reference to the other visions and can be used to evaluate costs and decarbonisation potential. | As long the European electricity grid has fossil-based power plants the wind power from Bornholm will replace some of this fossil power. | The decision on strengthened interconnectors needs to be agreed with neighbouring countries and the EU. | Strengthen power connections to all neighbouring countries and support the green transition of Polish power production by providing green electricity, thus replacing coal and natural gas. |

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# APPENDIX A – FUEL PROPERTIES

Table 7 shows the main chemical properties of renewable marine fuel alternatives in comparison with HFO.

Table 7. Summary of the properties of marine fuel alternatives. The colours from red to green shows an impact from negative to positive in comparison with each other.

| | $H_2$ (350bar) (gaseous phase) | $H_2$ (liquid phase) | LNG* | Methanol* | Ammonia (liquid phase) | HFO |
|---|---|---|---|---|---|---|
| Gravimetric energy density, [MJ/kg] [46] | 120 | 120 | 48.6 | 19.9 | 18.6 | 39 |
| Volumetric energy density, [MJ/m$^3$] [46] | 5,040 | 8,500 | 22,000 | 17,855 | 14,100 | 39,564 |
| Boiling temperature [°C], at 1 atm [46] [10] | -253 | -253 | -163 | 64.7 | -33.4 | 25 |
| Autoignition temperature, [°C] [10] | 500-570 | 500-570 | 537 | 470 | 650-657 | 250 |
| Flammability limit in air, [%vol] [46] | 4-74.2 | 4-74.2 | 4-15 | 6.7-36 | 15-28 | 0.6-7.5 |
| Flashpoint, [°C][10][47] | Not applicable | Not applicable | -188 | 11 | 132 | 65 |
| Toxicity [10] | Not toxic | Not toxic | Not toxic | Low acute toxicity | Highly toxic | Not toxic |

*Obtained from renewable resources

The energy density of fuels can be specified both in terms of a volumetric energy density (energy content per volumetric unit) and in terms of a gravimetric energy density (energy content per mass unit). High volumetric and gravimetric energy density imply less volume required and less weight on board a vessel.

The boiling point of a substance is the temperature at which the vapour pressure of a liquid equals the pressure surrounding the liquid and the liquid changes into a vapour. A low boiling temperature implies that liquid fuel must be maintained at low temperature or high pressure.

The main properties of fuels that influence safety measures on board a vessel are flammability limits, autoignition temperature and flashpoint. The flammability limits determine the range of volumetric percentages of the fuel in the air that can lead to a mixture ignitable at 25°C and atmospheric pressure. A wide flammability range indicates a highly flammable fuel. The autoignition temperature is the minimum temperature to which fuels in contact with air can ignite without a spark. Flashpoint of a chemical substance is the lowest temperature at which a liquid can form an ignitable mixture in air near the surface of the liquid. Materials with higher flashpoints are less flammable than chemicals with lower flashpoints.

In terms of toxicity, ammonia is a toxic, corrosive, with a strong characteristic odour, Repeated exposure to ammonia produces no chronic effects on the human body. Even in small concentration in the air, it can be extremely irritating to the eyes, throat and breathing ways. Methanol toxicity is very low and occurs only via ingestion, dermal absorption, and inhalation.

A comprehensive comparison between alternative marine fuels can be found here [15].

# APPENDIX B – $CO_2$ POTENTIAL

## DRY BIOMASS $CO_2$

The composition of biomass composition is shown in Table 8.

Table 8. Biomass ultimate analysis.

| | Straw[a] | Wood chips[b] |
|---|---|---|
| MC [$\%_{ARB}$] | 13.76 | 15.19 |
| ASH [$\%_{DB}$] | 7.55 | 0.95 |
| C [$\%_{DAF}$] | 48.51 | 50.46 |
| H [$\%_{DAF}$] | 5.98 | 6.03 |
| N [$\%_{DAF}$] | 0.87 | 0.21 |
| S [$\%_{DAF}$] | 0.16 | 0.07 |
| O [$\%_{DAF}$] | 43.79 | 43.2 |

MC: moisture content; ASH: ash content; FC: fixed carbon; C: carbon content; H: hydrogen content; N: nitrogen content; S: Sulphur content; O: Oxygen content; ARB: as-received basis; DB: dry basis; DAF: dry and ash-free basis

[a] Calculated as the average of 282 samples available at the ECN Phyllis Database: https://phyllis.nl/Browse/Standard/ECN-Phyllis#straw
[b] Calculated as the average of 22 samples available at the ECN Phyllis Database: https://phyllis.nl/Browse/Standard/ECN-Phyllis#wood%20chips

The definition of the content in as-received, dry, and dry and ash-free basis is shown in Table 9.

Table 9. Biomass ultimate analysis definitions.

| | Definition |
|---|---|
| ARB | C + H + O + N + S + ASH + MC = 100 |
| DB | C + H + O + N + S + ASH= 100 |
| DAF | C + H + O + N + S = 100 |

To calculate the mass of carbon contained in the biomass, $M_C$, Eq. (B.1) is used.

$$M_C = M_{Biomass} \cdot (1 - MC) \cdot (1 - ASH) \cdot C \text{ (B.1)}$$

Where $M_{biomass}$ is the mass of the biomass listed in Table 2. Considering Eq. (B.2) as the full-combustion reaction of the biomass, it is evident that all the carbon content of the biomass is converted to $CO_2$.

$$C_\alpha H_\beta O_\gamma N_\delta S_\varepsilon + \left(\alpha + \frac{\beta}{4} + \frac{\gamma}{2} + \varepsilon\right)(O_2 + 3.77N_2) \longrightarrow \alpha CO_2 + \frac{\beta}{2} H_2O + \varepsilon SO_2 + \left(3.77\left(\alpha + \frac{\beta}{2} - \frac{\gamma}{2} + \varepsilon\right) + \frac{\delta}{2}\right) N_2 \text{ (B.2)}$$

To calculate the mass of the carbon dioxide generated, $M_{CO_2}$ Eq. (B.3) is used.

$$M_{CO_2} = \frac{M_C}{27.3\%} \text{ (B.3)}$$

Where 27.3%, is the percentage of carbon over the total mass of $CO_2$.

WET BIOMASS $CO_2$

The volume of methane, $V_{CH_4}$, in unit of cubic meter is calculated using Eq. (B.4).

$$V_{CH_4} = \frac{E_{CH_4} \cdot 10^3}{LHV_{CH_4}} \text{ (B.4)}$$

Where $E_{CH_4}$ is the energy content of methane in unit of gigajoule given in Table 3, and $LHV_{CH_4}$ is the lower heating value of methane in unit of megajoule per cubic meter of methane, 35.8 MJ/kg.

The volume of carbon dioxide generated, $V_{CO_2}$, is calculated using Eq. (B.5)

$$V_{CO_2} = \frac{V_{CH_4} \cdot x_{CO_2}}{(1 - x_{CO_2})} \text{ (B.5)}$$

Where $x_{CO_2}$ is the percentage of $CO_2$ in a unitary volume of biogas, assumed 45% [48].

The mass of carbon dioxide generated, $M_{CO_2}$, is calculated using Eq. (B.6).

$$M_{CO_2} = V_{CO_2} \cdot \delta_{CO_2} \quad \text{(B.6)}$$

Where $\delta_{CO_2}$ is the density of carbon dioxide at normal conditions (pressure: 1 atm, temperature 0°C.

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