North Sea Energy

Energy transport and energy carriers

Report incl. deliverable

D3.2: Inventory of relevant P2X integration options

D3.3: Technical assessment and space requirements

D3.4: Assessment of the infrastructure implications of P2X activity

D.3.5: Assessment of the business case for individual P2X options

D.3.6: Drafting the final report and organizing stakeholder feedback session completed

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Management summary

This report analyses in an exploratory way the conventional supply routes of wind and natural gas as well as more innovative concepts of energy transport e.g. how offshore renewable energy, notably electricity from wind energy generated on the North Sea, can be converted into energy molecules in various power-to-gas (P2G) and power-to-liquids (P2L) options (collectively: P2X options). A levelised costs of energy (LCOE) analysis has been performed for the conventional supply costs of wind energy and natural gas. The natural gas system comprises of a 24 inch pipeline over 150km distance pipeline, and a 32 MW gas driven compressor (or 25 MW electric driven compressor) that provides an input pressure of 100 bar. The outcome shows, depending on the type of compression chosen a LCOE of gas transmission in the range of 0.05 – 0.09 ct/kWh (LHV). Although costs do not make up the single argument for cable type selection, TNO developed a costs optimisation model to determine (in a broad perspective) the transmission cost for various typologies of an electric system. The outcomes of the LCOE of a transmission system over 150km are in line with the 2.5 cent/kWh mentioned in literature. The analysis shows, in addition, that potential reduction in electric transmission costs can be realised when using island structures for systems located further from shore and with higher capacities. The system boundaries for the P2X processes are more complex. Some parameters are typically within the boundaries' scope, others, however, do have an impact on P2X processes, but still are not considered to be part of the system interlinkages analysed (for instance CO_2 supply, and market demand). In total, 12 P2X scenarios were analysed to gain insight in the effect of location and scale on the business cases, all these scenarios entail a wind-electrolyser capacity ratio of 30%. Because the location of production is yet unknown, this study only considers new dedicated pipeline infrastructure for hydrogen transport and ships for the other PTX options. A broad qualitative screening, for instance on market potential and offshore applicability, was conducted to select the P2L technologies and based on the criteria set methanol and ammonia seem to be the most attractive routes, so these options were studied via a net present value analysis in more detail. The NPV analysis show that future (sandy) energy islands are the most ideal locations for large-scale or even bulk production of carbon-free hydrogen, carbon-free methanol and carbon-free ammonia, because of the economics of scale that can be realised nearby the availability of carbon-free electricity and the ability to host a multitude of functionalities, including shipping activity that also enables to transport methanol and ammonia to the most optimal markets. Moreover, it seems likely that any legal, safety or public acceptance restrictions related to onshore energy conversion and storage, may be much less of a problem if such activity takes place offshore. Small-scale conversion is assumed to take place on (existing) platforms that are equipped with P2X - as well as with a 100 MW electrolyser-capacity. Based on these assumptions 330MW of wind capacity is required to deliver the input required for the small-scale P2X process; remaining energy may be transported via an electricity cable. The small-case offshore conversion does not provide a positive system value and is in comparison to onshore production less favourable. In the analysis all kinds of technical, spatial and economic considerations related to P2X activity were analysed. This has been done under due recognition of the fact that in the absence of a clear policy regime towards the carbon-free energy molecules or carbon-free feedstock, and given that these relevant carbon-free conversion technology systems are on the whole still in their infancy and therefore still will have to benefit from learning effects driving down CAPEX levels, there currently is not yet a clear business case for offshore conversion, irrespective whether this is into hydrogen, methanol or ammonia. The prime challenge therefore seems to be to get clarity about the future policy regime on this to activate the optimal future carbon-free energy (by industry) and feedstock mix in line with the EU mitigation targets. A clear perspective has already been set by EU Renewable Energy Directive (RED II) for synthetic e-fuels supplied to road transport, shipping and aviation, which could already greatly improve the business case.

Introduction

In this report we will address in an exploratory way the conventional supply routes of wind and natural gas as well as more innovative concepts of energy transport e.g. how offshore renewable energy, notably electricity from wind energy generated on the North Sea, can be converted into energy molecules in various power-to-gas (P2G) and power-to-liquids (P2L) options (collectively: P2X options). This will be done by what is sometimes considered to a research gap [2], namely by way of a techno-economic analysis in which these various supply options are put in perspective with traditional supply routes of offshore power and gas.

These innovative options might be promising for the future, given that the volumetric energy density of hydrogen is about 4 times lower than that of liquid fuels. In addition, given the overall expected demand in North Western Europe for low-carbon molecules both as energy carriers and as feedstock, there is a growing belief that a serious part of the offshore renewable energy production will at any stage need to be converted into carbon free molecules in order to satisfy demand [1] [2] [3]. This demand may involve low-carbon hydrogen, low-carbon methanol, low-carbon ammonia and low-carbon products based on these. To the degree that policies and measures will be installed to phase out ‘high-carbon’ versions of these products, the business case for these low-carbon alternatives will follow automatically. Measures that require limited adjustment to the often already existing, infrastructure can already stimulate the production of low-carbon at a short notice. For instance, admixing hydrogen to natural gas flows up to some 20% is considered to require little adjustment in transport and most of the implementation modes. Also simple methanol fractions up to 3% usually do not require any modifications to the vehicle, although admixing 3-15% methanol typically requires adaptation of fuel system materials (plastics) getting directly into contact with methanol [3]. Besides stimulating the uptake of low-carbon molecules, the business case will be supported by learning effects driving down technology CAPEX levels (probably significantly, cf other conversion technologies), and by increasing the production size such that economies scale can reduce costs further. Large-scale offshore production of P2X options may become a serious option if on the North Sea there will be a trend towards installing offshore artificial energy islands either by using current versions of, or extending, offshore platforms, or by introducing new ‘sandy’ energy islands.

The following research questions will subsequently been addressed to make an assessment of the techno-economics of these innovative P2X options

- What are the costs of conventional supply routes for offshore wind and natural gas?
- What are the techno-economic potential of some of the main P2X technologies for North Sea system integration?

The report is structured as follows. The methodologies, system boundaries and scenario specifications are addressed in Chapter 2. Chapter 3 provides an overview of the costs of the conventional supply routes of offshore energy from wind and natural gas, whereas Chapter 4 describes the various P2X technologies considered. Chapter 5 provides a detailed assessment of the various relevant energy value chain processes, including the electrolysis and other P2X conversion processes as well as the transport processes of the various energy carriers considered. Chapter 6 covers more detailed information on the spatial requirements of the various P2X options, while chapter 7 shows the main outcomes of the technologic-economic assessment for P2X. The report concludes with a comparison of the various options (Chapter 8).

Methodology and scenarios

This chapter describes the energy supply scenarios considered in this report, both with respect to the traditional supply system and to the innovative P2X options. Per scenario clear systems boundaries will subsequently be defined and the model and economic parameters used to compare/evaluate the various alternatives will be discussed.

Description of all scenarios

Table 1 provides an overview of all transport scenarios considered to assess the various means of offshore energy transport. There are currently two ‘conventional’ offshore energy transport modes: that of natural gas and that of electricity: in the following both are included. As far as the traditional offshore transport costs of electricity is concerned, the reader is also referred to the NSE3, D3.8 outcomes on offshore energy islands. These outcomes (especially from the all-electric scenario) will be shortly reflected here, as a benchmark to the electric transmission transport scenarios via an offshore substation or via an artificial island.

The comparison between the P2X scenarios considered relates to two main dimensions. First, to compare offshore versus onshore P2X, and second, to compare small-scale with large-scale P2X. Note that in the following small-scale conversion is assumed to take place on (existing) platforms that are equipped with P2X- as well as with a 100 MW electrolyser-capacity whereby we assume a wind-electrolyser capacity ratio of 30%, i.e. suitable to deliverer a relative continuous supply of hydrogen. Based on these assumptions 330MW of wind capacity is required to deliver the input required for the small-scale P2X process; remaining energy is transported via an electricity cable.

Table 1: Overview of all scenarios.

		Reference		Hydrogen		Ammonia		Methanol	
		Natural gas	All-electric[1]	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
330 MW	Cable capacity (MW)	Single price reference @ 150 km	150 km distance to shore, 220kV AC transmission system						
			330	330	230	330	230	330	230
	Electrolyser capacity (MW)		0	100					
5 GW	Cable capacity (MW)		150 km distance to shore, 525kV DC transmission system						
			5,000	5,000	3,500	5,000	3,500	5,000	3,500
	Electrolyser capacity (MW)		0	1,500					

P2X scenarios

Because this study also intends to cover P2X economics of scale, several power-to-hydrogen (P2H) scenarios specifications have been considered (Table 2): two onshore and two offshore, and two small-scale (100MW) and two large-scale (1,500MW). The small-scale production option is based on the scale of a platform, but the large-scale one requires the size of an (sandy) artificial energy island. The volumes of hydrogen produced offshore are either transported to shore via a pipeline, or can be converted on location to ammonia or methanol and shipped to shore.

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[1] The all-electric reference case includes a comparison between platform and island structures for power transmission.

Table 2: Overview of P2H scenarios

Scenario	5 GW		330 MW	
Capacity (MW)	1,500 MW		100 MW	
Location	offshore	onshore	offshore	onshore
Production scale (tons/day)	560		36	

Just as in the hydrogen scenarios also in the power-to-ammonia (P2A) and power-to-methanol scenarios several comparable specifications have been considered (Table 3 & Table 4). Because the industrial production scale of ammonia is assumed to vary from 5 tons/day [3] to 3,300 tons/day [4], production processes are scaled up or down to the relevant power capacities in the various scenarios. The industrial production scale of methanol is assumed to vary between 5 tons/day [3] and 7,000 tons/day [5]. The wind-electrolyser capacity ratio is, again, assumed to be 30%, whereas the P2A scenarios only consider 100% conversion of the hydrogen.

Table 3: Overview of P2A scenarios

Scenario	5 GW		330 MW	
Capacity (MW)	1,500 MW		100 MW	
Location	offshore	onshore	offshore	onshore
Hydrogen input (tons/day)	590		39	
Production scale(tons/day)	3,330		220	

Table 4: Overview of P2M scenarios

Scenario	5 GW		330 MW	
Capacity (MW)	1,500 MW		100 MW	
Location	offshore	onshore	offshore	onshore
Hydrogen input (tons/day)	670		44	
Production scale (tons/day)	4,560		300	

Scenario boundaries

System boundaries clarify which processes are included in a techno-economic analyses such as in the present one on P2X (Figure 1). Some parameters are typically within the boundaries' scope, others, however, do have an impact on P2X processes, but still are not considered to be part of the system interlinkages analysed. Examples are: the power generation, CO_2 supply, or market demand; they therefore are considered as exogenous factors.

So, the power generated by offshore wind parks is an exogenous variable for which a price of €50/MWh has been assumed; how such electricity has been distributed towards the conversion system analysed has therefore been left outside the scope of the study. Offshore conversion to synthetic hydrocarbon-based products by definition requires a carbon source (CO or CO_2). However, just as with respect to power, also the carbon supply has been treated as an exogenous variable. So, whether the carbon would be sourced from e.g. direct air capture or industrial sources therefore falls outside the scope of the study. The only exception relates to our analyses comparing onshore and offshore methanol production; there attention has been given to the impact of offshore costs of CO_2 transport/utilisation (assumed to range between €-30 and €120 per ton of CO_2 transported. The option of negative CO_2 prices included in the range assumes a fee for uptake). The system boundaries of this study end physically at the delivery point onshore (landing point). At that point an economic value is assigned to the product based on normal market prices, which is compared to the cost-price (based on levelised costs) of producing and transporting a unit of the energy carrier considered to that

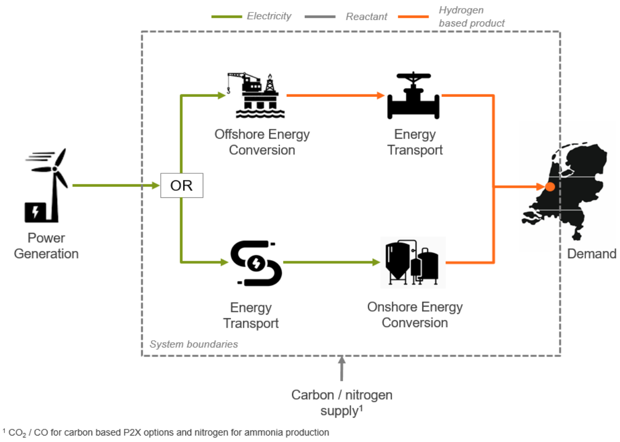

Figure 1: system boundaries

particular landing point. How the product next is distributed towards its subsequent user or final consumer is therefore not included in the analysis.

Activities falling within the system boundaries typically are the conversion and the transportation of the energy carrier to shore. Conversion is assumed to take place either on an offshore O&G platform, or on an energy island (see also D. 3.8). The complexity of offshore operation and installation will be dealt with via sensitivity analysis on offshore cost factors, i.e. relative to onshore costs. Offshore production costs are generally expected to be higher due to the more difficult circumstances at sea, but how much? Despite known experiences and data from e.g. gas production on offshore platforms or coastal areas that could be of some value, much is still unknown about the actual offshore costs factor of P2X. The sensitivity analysis on the impact of the offshore cost factor on the economics of offshore P2X is meant to clarify the importance of this factor. The energy carrier (or feedstock) generated by the offshore conversion process needs to be transported to shore. Because the location of production is yet unknown, this study only considers the following transport modes: the electric grid, new dedicated pipeline infrastructure, and ships; using existing gas infrastructure is therefore not taken into consideration (which may create an upward bias on transport costs).

Model setup

In order to compare various setups of the complete chains considered, assumptions and choices need to be transparent and easily traceable. A material energy flow analysis (MEFA) structure is used to build the various setups. A MEFA combines a material flow accounting system (MFA) with an energy flow analysis (EFA). The MFA reports only the physical material flows in a socio economic system from their origin, e.g. extraction of raw materials, to final use and disposal or reuse. An energy flow analysis (EFA) can have the same system boundaries as an MFA, but bases its flows on energy content rather than on mass [6, p. 99]. The MEFA combines both approaches with the aim to measure and account material and energy flows going through a metabolism system thereby linking material and energy flows related to the same economic activity [8]. One of the main purposes of a MEFA model is to be able to evaluate energy flow quantities, such as in our modelling electricity consumed by the desalination and compression units, in a techno-economic context. Within the boundaries of the offshore business ecosystem considered the model therefore needs to calculate the quantities of the main value stream components of hydrogen production, i.e. including conversion, transportation efficiencies and generated revenues.

Economic evaluation

In the economic evaluation of conversion options, in the following two economic concepts have been used: the net present value (NPV) of investment, and the levelised cost of energy (LCOE). For an investor, the economic value of an investment considered can be determined by subtracting its upfront investment capital expenditure costs from the discounted sum of expected future cash flows in order to get to the NPV (Equation 1).

$$NPV = \sum_{t=0}^{N} \frac{FCF_t}{(1+r)^t}$$

Equation 1: Calculation of the net present value[2]

LCOE is a variable that can be used to compare for instance lifetime costs of alternative energy generation modes (Equation 2). The LCOE portrays the constant energy price required for the revenues generated from the project to be just sufficient to return the costs based on the discount rate [9]. Although our LCOE definition is slightly different from the often used one of the Department of Energy's National Renewable Energy Laboratory (NREL), no serious differences are expected, because the project considered assumes: constant annual output and costs, that all construction spending occurs in the first two year[3], and that there are no decommissioning costs. [Note in this regard, that the NPV measurement used in the oil and gas industry is not taking into account any discounts on the energy side. Financing costs, besides the WACC, are not taken into account[4].

$$LCOE = \frac{\sum_{t=0}^{N} \left[\frac{I_t + O_t + F_t}{(1+r)^t}\right]}{\sum_{t=o}^{N} \left[\frac{E_t}{(1+r)^t}\right]}$$

Equation 2: Calculation of the LCOE[2]

It is important to state with regard to variables such as NPV and LCOE, that they can be well used to benchmark or rank various straightforward economic scenarios, but generally fail to take wider system costs, such as the value of dispatch ability or dealing with intermittency, into account.

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[2] Where: FCF is the free cash-flow; I_t is the total capital expenses in year t; is the total Operation and Maintenance (O&M) costs in year t; F_t the fuel cost in year t; and E_t the energy generated in year t. r is the risk adjusted discount rate set at 10%.

[3] This implies that there are no revenues in the first two years.

[4] We assume a weighted average cost of capital (WACC) of 10%; WACC includes basically costs linked to interest, inflation, and equity financing.

Conventional Energy Transport

This chapter assesses the costs of conventional supply routes for offshore energy that serve as a benchmark to the analysis of the feasibility of P2X options. It includes both the net present transport costs (NPC) for national gas and for offshore wind energy.

Natural gas

This section only discusses the costs of offshore natural gas transport, not those of exploration, extraction and quality processing. Its summary variable is the net present cost distribution for a particular case, given a 24" pipeline and a transportation distance of 150 km.

The main defining parameters for the CAPEX of the pipeline are, next to the choice of material, the pipeline diameter and the distance that needs to be covered, i.e. the total pipeline length [9]. To determine the diameter of a pipeline, it is important to know the required pipeline capacity and the tolerated flow speeds of the gas. Based on the NSE Atlas[5] information on the 24" LoCal pipeline, a natural gas capacity of some **360 ton per hour** was used as a base for the calculations. The CAPEX levels for pipelines with different diameters is shown in Figure 2.

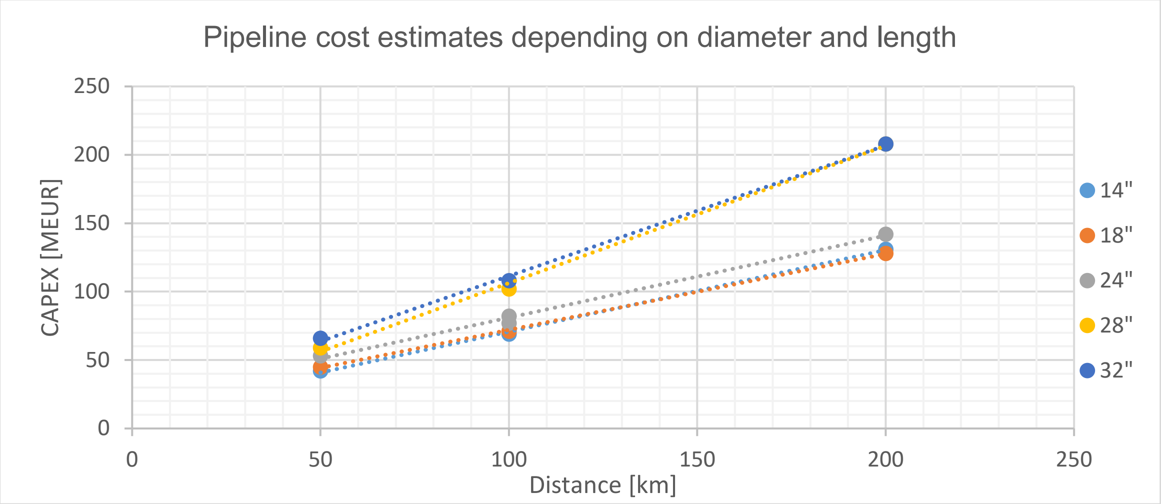

Figure 2: Pipeline cost estimates as a function of diameter and length (author's figure, based on [9])

It is important to mention that in practice there are more costs related to the installation of pipelines which are, however, not taken into account in this study due to undefined locations. To such costs belong e.g. those related to pre-installation surveys and tests as well as the CAPEX of crossings. Compression of natural gas is required in order to transport it over (large) distances to the onshore point of connection. Larger pressures result in higher volumetric energy contents and thus smaller pipeline diameters are required. This in its turn also impacts other design criteria of the chosen pipeline system e.g. the material requirements. Regarding the costs of natural gas compressors, one can distinguish between the required capital investment for the compressor itself and the operating costs which typically consist of maintenance and energy costs. To identify the CAPEX of an compressor one needs to estimate the required work of compression, the compressor type and drive efficiency needed.

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[5] https://www.north-sea-energy.eu/atlas.html

Assuming an input pressure of 100 bar (pipeline operating pressure), the fluid compression work is calculated according to [10] and [13], and results in a total compression power of some 24 MWth excl. drive.[6] Depending on the drive system the total electric capacity (some 25 MW for an electric and some 32 MW for a natural gas driven compressor)[7] and energy consumption is calculated. The results are compared to the and are in line with the MWe compression capacity discussed in D. 3.5 where compression capacity at K14 accounts for some 27 MWe.

Intermediate compression is assumed not to be required based on the pressure drop model (see page 20).[8] This results in an outlet pressure at a distance of 150 km of some 80 bar. A ballpark figure for the compressor CAPEX is retrieved from [13]. For O&M, 8% p.a. of compressor CAPEX is assumed. Table 5 provides an overview of the main parameters used in the cost calculates for natural gas transmission.

Table 5: Main parameters NPC natural gas transmission

Parameter	Value	Parameter	Value
Distance	150km	Pipeline diameter	24 inch
Volume	360 ton//h	Input pressure	100 bar
OPEX	8%	Output pressure	80 bar
Period	20	WACC	10%
Density NG	0.716 kg/m³	Compression capacity incl. elec. Drive	25.32 MW
Electricity price	50€/MWh	Compression capacity incl. NG drive	32.07 MW
Gas price	16 ct/kWh		

Figure 3 visualises the distribution of costs over three different cases which differ only in terms of their drive system and the energy costs. One can observe that the costs for energy (if monetized) and the pipeline CAPEX represent the major costs for all cases. The transport costs of NG result in some 0.05 – 0.09 ct/kWh (LHV). The natural gas based compression cases (B & C) result in a lower NPC compared to the electricity based compression even though this includes larger volumes of natural gas transported and a larger drive efficiency (less energy requirement). However, one should mention that a general conclusion on whether electrification of offshore platforms is beneficial cannot be drawn from this broad analysis. Calculations have shown that the case is very sensitive to future electricity and gas prices. In addition, the environmental impact of natural gas based compression, savings on CO2 emission rights as well as other aspects such as higher availability of electric drives lead already in specific cases to an electrification of offshore O&G platforms.

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[6] This is an indicative figure. Compression duties vary widely among different applications due to the wide variation in gas (and oil) fields regarding production characteristics such as composition, pressure and flow rate.

[7] Estimated efficiencies: η_{el}=95% and η_{NG}=75%

[8] To calculate the pressure drop the molecular weight and flow rate of natural gas is adapted in the pressure drop model.

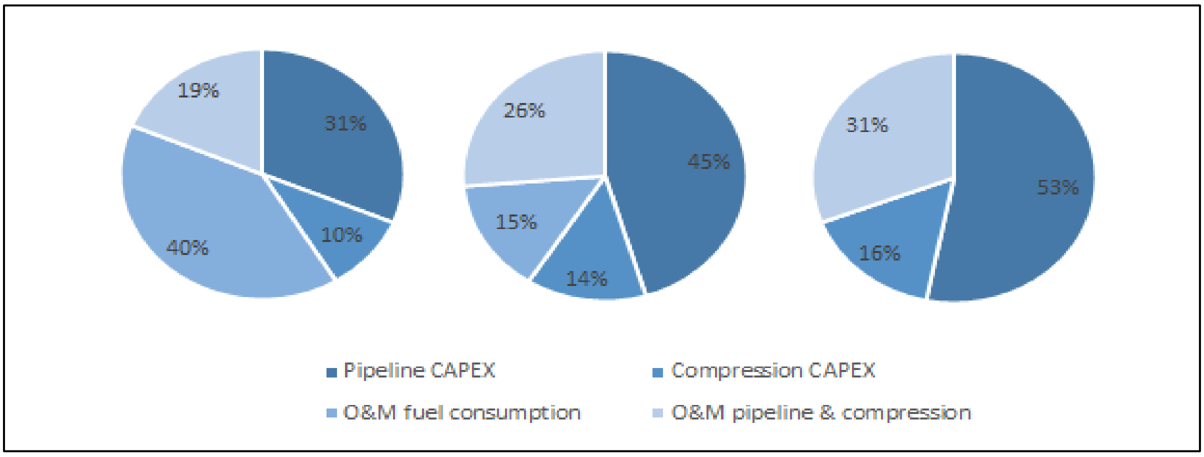

Figure 3: NPC distribution of natural gas transport depending on compression drive system. From left to right: A: NPC of 376M€ - Electric drive with electricity costs = 50 EUR/MWh, B: NPC of 259M€ Gas drive fuelled with extracted gas and costs = 16 ct/kWh, C: NPC of 222M€ Gas drive with no costs for fuel (extracted gas is used)

Electricity

Figure 4 highlights the system components of a HVAC HV system that are considered for the 330 MW reference platform case. The length of the export cable is set on 150km (220kV). TenneT standardized the connection method for Alternating Current (AC) technology to 220kV, as this will be the best solution for connecting wind farm zones located relatively close to the Dutch coast to the grid [12][9]. Each of these standardized collection system has a capacity of 700MW. The application of AC technology over such a distance still seems to be advantageous over DC-technology, due to the limited capacity of offshore wind to be transported.

330MW transmission system platform to shore		
220kV HVAC transmission - 150km		
Platform **66kV - 220kV** Transformer costs (step-up) Switch gear costs Installation costs	HVAC cable costs (procurement) cable laying and losses reactive power compensation costs	**Onshore substation** **220kV - 380kV** Transformer costs (step-up) Switch gear costs Installation costs

5 GW transmission system island to shore		
Requires parallel systems as 5GW is due to grid frequency requirements and due to the 2GW unit size		
525 kV HVDC transmission - 150km		
Island **66kV - 525kV** Transformer costs Converter costs (AC-DC) Installation costs	HVAC cable costs (procurement) cable laying and losses reactive power compensation costs	**Onshore substation** **525kV - 380kV** Transformer costs Converter costs (DC-AC) Installation costs

Figure 4: Schematic overview various electric transmission systems

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[9] HVAC is still the most common technology applied to the offshore system mainly because of its reliability (about 99.1%) [13].

Information regarding the failure and hence reliability of export cables used for offshore wind applications is lacking in the public domain. Edif ERA has carried out a number of physical dissections and root cause analysis of failed export cables and accessories from wind farms over the last two years, the findings of which are confidential and not published. The best failure data currently available was obtained from a Siemens Round 3 wind Farm reliability model for the Hornsea project [16]. They assumed a 0.1 failures per 100km per year failure rate. The same paper has analysed, based on discussions with offshore wind farm operators, the effect of one export cable failure on the wind farm output. The effect on energy losses per connection reduces significantly by installing multiple cables e.g. from 0.29% for 1 export cable to 0.03% per year in case of 4 export cables [16].[10] The energy losses of a copper 220 kV cable is 63.3 Watt/meter considering that the load in each section is limited to the maximum circuit load (landfall rating) [16]. Hence, considering the 330MW case losses will add up to 2.9% of the total energy. For the planned outrages an energy loss of 1% is assumed for a single export cable. This leads to a total energy loss of 4.2% (330MW) of the total energy produced by a 330MW wind park transported over 150km via a 220kV cable. The technical feasibility of the cable typology is questionable.

The recently increased roll out of HVDC projects across Europe, notably in the adverse offshore environment, underlines the need for improving the reliability and availability of HVDC cables and systems. Mass Impregnated (MI) cables and systems are mature up to voltages of 525 kV and available up to voltages of 600 kV [14]. Based on statistics from CIGRE HVDC the average fault of the subsea cables is 0.07 faults per 100km/year. Although the average fault rate with HVDC cables is low, yet when such do occur, they may be difficult to locate and require considerable resources and time to repair. The mentioned CIGRE SC B1 cable fault statistics shows that submarine cable fault average repair duration was 60 days. This leads to unplanned outages for the 5GW case of some 0.35%. The PCI Gridlink project[11], a 525kV cross-border interconnection between France and the UK, counts with planned outages of 2%. The cable losses are set to 0.5% as well, bringing total system losses up to 2.85% for the 5GW cases. Figure 4 highlights the system components of a HVDC HV system that are considered for the 5GW reference island case. The length of the export cable is set to 150km.

Although costs do not make up the single argument for cable type selection, TNO developed a costs optimisation model[12] to determine (in a broad perspective) the transmission cost of the electrification part of the scenarios. The methodology of this model is described in D. 3.8 on offshore energy islands. Figure 5 provides insight in the transmission costs of platform and/or island structures on the basis of NPC of electricity transport. Noteworthy is that cables in the 330MW scenarios are far more expensive. To a large extent this can be explained by a larger distance (150 rather than 60km) for the 330MW scenario. Nevertheless, it is expected that NPC for this electric system are slightly overestimated for lower capacities, especially, given the standardisation of the 700MW variant by TenneT. Another important outcome is the reduction in electric transport cost in comparing the platform and the island case. Offshore structure costs for HVDC conversion are high, so that if this can be done on islands, this may lead to serious reductions in the cost price of electricity transport from offshore wind. Next to that, outcomes show that island structures only become of interest for the electric system for locations further from shore and with higher capacities. Island structures seem to already lead

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[10] The estimated repair time for unscheduled export cables is 21 days with estimated material costs summing up to about €250.000 [16]. The rate for a repair crew/vessel is about €110.000 per day. The cable faults on array cables and land export cables are not considered.

[11] https://tyndp.entsoe.eu/tyndp2018/projects/projects/285

[12] TOET tool, TNO, for more information see Appendix I from Offshore Energy Islands D3.8

to lower LCOE of transport at a 5GW scale. The outcomes of Figure 6 are in line with the 2.5 cent/kWh figure mentioned in literature.[13]

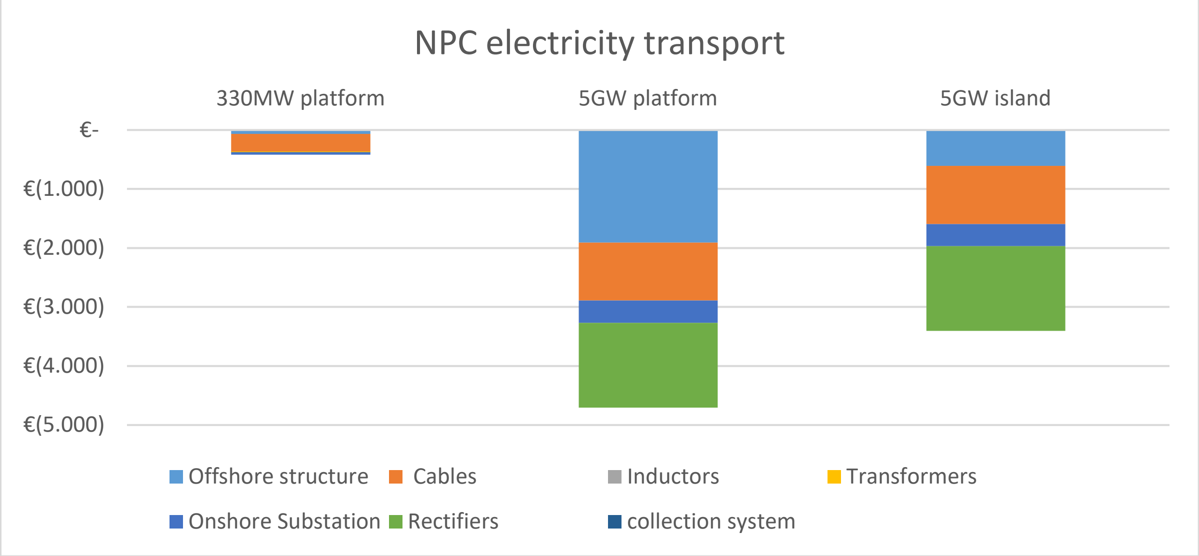

Figure 5: NPC distribution of electricity transport depending on scale and offshore substructure

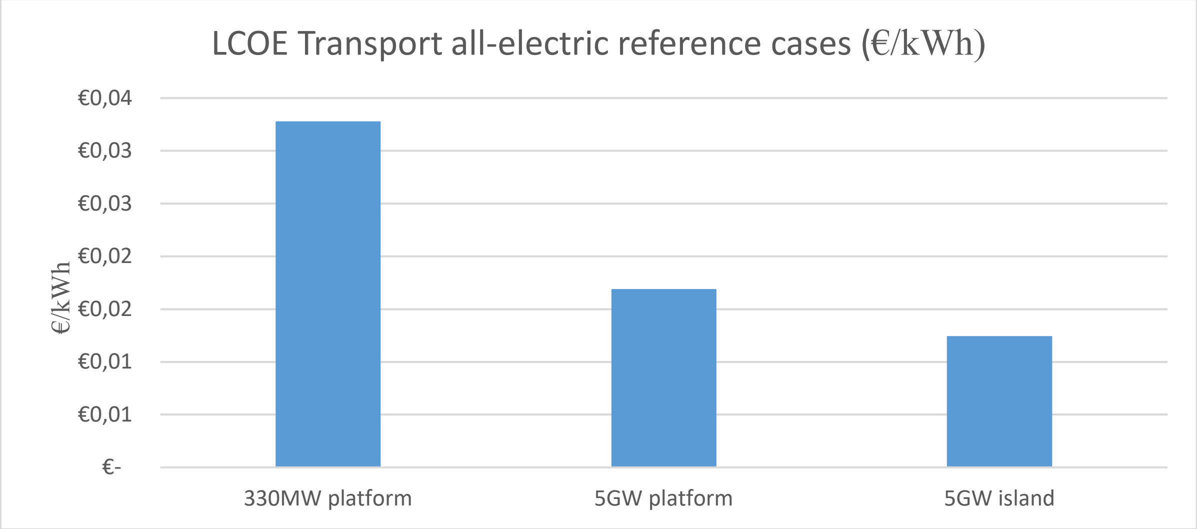

Figure 6: LCOE transport costs comparison for all-electric reference cases with platforms and island

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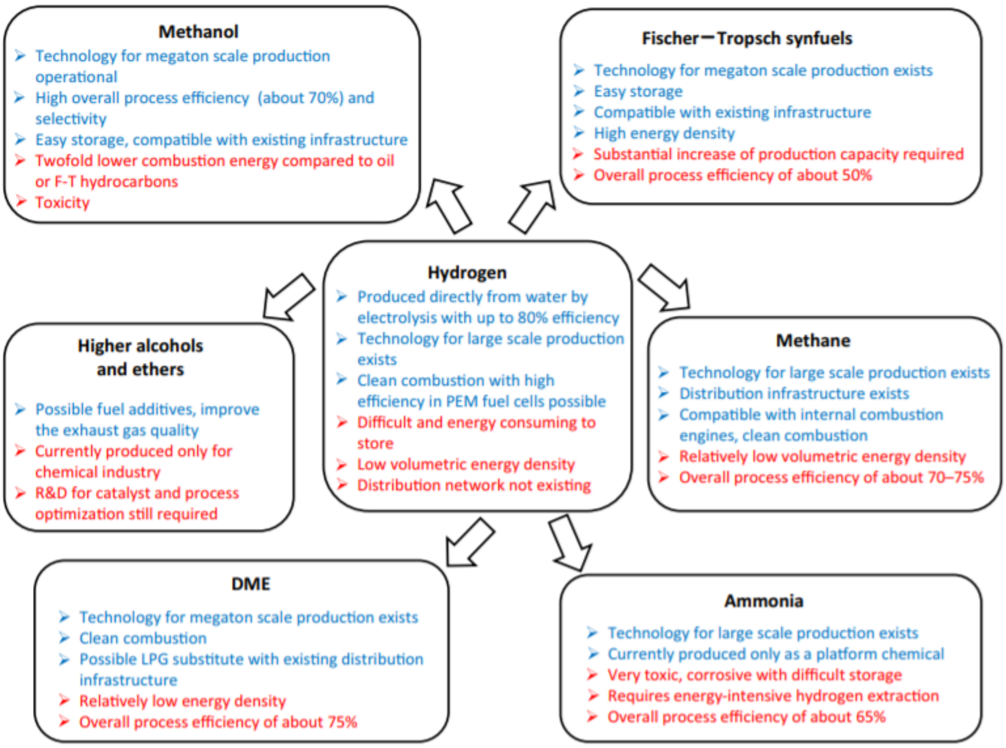
[13] https://www.rekenkamer.nl/binaries/rekenkamer/documenten/rapporten/2018/09/27/focusonderzoek-kosten-van-windparken-op-zee/Focus+op+Kosten+windenergie+op+zee+WR.pdf

Inventory of relevant P2X integration options

A broad qualitative screening is conducted to select the P2X technologies Figure 7) that show a high potential for offshore and onshore application and also fall within the scope for the industrial stakeholders of the project. The selection of the available P2X options has been based on a set of qualitative criteria and expert recommendations:

1. Storage potential: energy density of the P2X product at ambient conditions (pressure and temperature).
2. Efficiency: the efficiency of the process considering the loss of hydrogen (i.e. water as a product).[14]
3. TRL & scalability: development stage of P2X technology and currently applied scale.
    a. HSE: possible health, safety and environmental concerns.
4. Offshore applicability: barriers and opportunities for P2X options taking place offshore compared to onshore conversion. Points of consideration are the possibility to supply the energy to the offshore conversion location and then transport the energy carriers to shore.
5. Market potential: this criteria assesses the market potential for a more sustainable substitution of the (mostly) fossil fuel based hydrocarbons. In addition the eligibility of the P2X options under the under existing policy frameworks (e.g. RED II) could greatly improve demand for clean fuels and the business case.



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[14] One should note that additional energy penalties are incurred for any of the conversions starting from hydrogen, which is a disadvantage of all other energy carriers. The additional energy required is different for the various options and depends not only on the energy carrier generated but also on details of production and waste heat integration and utilization.

Figure 7: Main merits and drawbacks of hydrogen transformation pathways into various potential energy carriers (adapted from [2, p. 184]). DME - dimethyl ether.

A primary step in the P2X process is the production of carbon-free hydrogen. Current hydrogen production accounts for some 65 million tons per year intended for processing in the chemical and refinery industry [4]. Next to that, there is a potential to apply hydrogen in power generation (gas turbines) and in the mobility sector (fuel cell vehicles, combustion engines). Storage of pure hydrogen is on the whole rather costly as it requires either high pressures (up to 1000 bar), or very low temperatures due to its low boiling point (-253°C). Hence, processing hydrogen into other chemical compositions may be beneficial. An overview of all considered P2X options is given in Appendix A. Overview of P2X options. Here the various P2X options are compared on the above criteria in order to have a first order insight in offshore P2X options.

Given the above criteria, the use of hydrogen for synthesis of methanol and ammonia seem to be the most attractive routes, so that these options have been analysed in more detail. Among all synthetic chemicals, ammonia has the main share with a global production of some 180-200 Mt [15]. About 80% of the ammonia is used to produce nitrates which are essential for fertilizers. The remaining part converts into nitric acid, plastics and pharmaceuticals. Almost all ammonia is, next to nitrogen, based on hydrogen produced by coal gasification or steam reforming of natural gas. The Haber-Bosch production technology exists already at megaton scale, but small-scale ammonia production for decentral ammonia production is gaining more attention. The value of (high-carbon) ammonia in the market is around 200-250€/ton at producer side (in the US); however, taking transport to harbours into account a price of 300-350€/ton would probably be more representative. Producing carbon-free ammonia, in contrast to the current means of production, does not emit any carbon. In order to currently compete with (high-carbon) ammonia the CO_2 price should rise to 150-200€/ton [15]. The expectation is that for a timely development of carbon-free ammonia a separate market needs to be developed for it which focuses on the application of ammonia as an energy carrier, rather than as feedstock for the chemical industry [15]. The resources for ammonia production (water and nitrogen) are easy accessible offshore, and only require separation units to be acquired.

Methanol can be considered to be a possible energy storage alternative to oil. Methanol is in a liquid state at ambient pressure and temperature, which makes it generally easier to store and transport than hydrogen [16]. In general, it can be also used purely in Otto engines, or blended with gasoline. Its current production accounts for some 30 Mt per annum, mainly applied in synthesis of formaldehyde, methyl tert-butyl ether (MTBE) atoned acetic acid [2]. There is much experience with methanol in the oil, gas and chemical industry where the technology for megaton scale production is already operational. Water and CO_2 are the resources for methanol, where the latter is a challenge for offshore production but also brings interesting opportunities for system integration. Lastly, the offshore generation of heat has not further been taken into account as there is a lack of large heat consumers offshore and the transport of heat over longer distances to shore is neither efficient nor effective.

Process description

This chapter gives an overview of the main processes required for the selected P2X options: the processes to generate power from various wind profiles (incl. their back-up requirements); the hydrogen production process (incl. desalination); and ultimately the production processes for ammonia and methanol. Transportation solutions by ships for methanol and ammonia are discussed at last.

Production profile

The stochastic nature of wind energy production is well known, with wind farms outputting highly variable production profiles over time. The wind energy production profile is assessed on the basis of the power curve established by HINT (see Appendix B.). The power curve was validated by calculating a turbine's capacity factor at each of the wind sites, and comparing it to the published results for the Haliade-X in the North Sea (63%). The wind energy production profile is an important parameter in the P2X process because it affects the operational patterns of all subsequent processes. In the timeframe analysed, it is assumed that PEM electrolysers will have a flexibility range of 0-100+%, making them compatible with this production profile.[15]

The synthesis activities required for the conversion of hydrogen to ammonia or methanol, however, must be continuously processed, with a limited range of flexibility. With this minimum requirement, there is a necessity to utilise some combination of electrical storage, hydrogen storage and back-up power to ensure that the power to the system and input flows for the P2X sub processes remain continuous. What the size and costs of these back-up options would be, and how much energy they would deliver to the system over a year, cannot be determined by an analysis of the frequency of occurrence of different power levels from the wind farm. Rather, the time domain of real data must be examined to make such predictions.

The operational mode of the electrolyser is also an important factor in this analysis, as it determines a hydrogen feed profile to the synthesis processes. Optimisation of the operational mode can lead to serious cost-reductions in the cost price of hydrogen. The analysis uses constant production as operational mode for the electrolysers. In this mode, the electrolyser will operate at its nominal capacity whenever there is sufficient wind power, with the surplus of power being transmitted via the electrical transmission system. When the wind power is below the nominal capacity of the electrolyser, all of it is converted to hydrogen, meaning that there is no power transmission via the cable (Figure 8). The advantages of this would be: much more constant production of hydrogen (with an average wind energy covering factor of 25%); higher conversion and compression efficiency; the highest capacity factor for the electrolyser (a very significant cost factor); and smaller storage/back up power requirements for the P2L cases.

The disadvantages of this operational mode would be the opportunity cost of electricity sales at sometimes higher prices (essentially fuel cost for the electrolyser) and a highly variable electricity production profile (and less efficient use of electrical infrastructure). These other operational modes, and their advantages and disadvantages, are outlined in Appendix C. Production Profiles.

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[15] Literature indicates that the current PEM electrolysers require at least a 5% infeed of the capacity. Though, technological improvement is expected in this field reaching a minimum 0% infeed by 2025 [23].

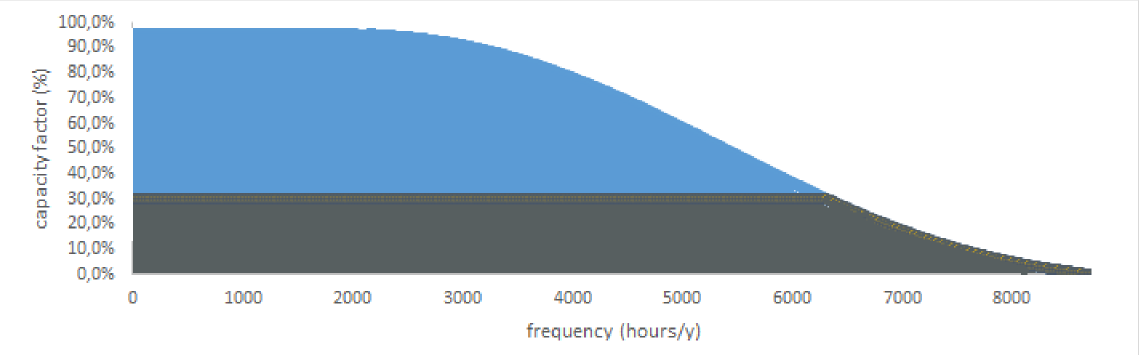

Figure 8: Frequency domain outline of constant production mode (light blue: wind profile; Greydark blue: hydrogen profile).

The Haber Bosch process for ammonia production, at the scales we examine, is estimated to have a minimum operating capacity of 40%. The methanol synthesis process is presumably less flexible still, and we assume that 80% is a minimum operating capacity [21] [15]. Given the highly variable nature of production, for any given operational mode, some storage of electricity, hydrogen, or supply of backup power, is required to meet the process demands. The back-up requirements are examined under the constant production profile. For each hour, the model checks if there is sufficient power to match the nominal requirements of the relevant P2L process (electrolyser and synthesis power demands), and to match the minimum power requirements. Assuming a €50/MWh market price for electricity, some 670 TWh/a and 1.900 TWh would be required to maintain the minimum flexibility requirement of the P2L processes (Table 6, 5 GW). In this situation a bi-directional cable is far more economically feasible (assuming no significant cable costs to facilitate bi-directional energy transport), than back-up solutions brought forward by battery or hydrogen storage solutions. The costs of these back-up solutions are extensively discussed in Appendix D. Back-up power solutions.

Table 6: Back-up demand for P2L processes

Case	330 MW		5GW	
P2X process	NH3	MeOH	NH3	MeOH
Minimum demand (% nominal)	40%	80%	40%	80%
Hours in deficit / year	1672	2384	1672	2384
Grid energy needed/year (MWh)	44,153	125,100	668,988	1,895,456
Cost of grid electricity (€/year)	2.207.662	6.255.006	33.449.421	94.772.817

Hydrogen production process

PEM Electrolyser

PEM or Proton Exchange Membrane electrolysers were developed to deal with issues related to current density, partial load and operating pressure present in Alkaline Electrolysers. PEM electrolysers can operate under a wide range of input power, due to lower inertia effects than those seen in liquid electrolytes, and, because of the low permeability of their membranes, the oxygen output side is not contaminated by hydrogen when operating at low power [22]. Additionally, when operating at low power, their efficiency actually increases, contrary to many engineering processes, as the freest molecules are pushed through the membrane [9].

So, PEM electrolysers have significant advantages over their Alkaline alternatives. The primary advantages for the system is the significantly lower minimum load (3%-10% instead of 20%-40%) and much shorter start-up time from cold to minimum load (5-15 minutes rather than 20-60+ minutes). PEM electrolysers have the capacity to run above their nominal capacity for short periods of time also, being currently able to operate at 160% of P_{nom} for a 10 minute period. By 2025 the minimum load is expected to be 0%, and the max load to be 200% of P_{nom} for the same 10 minute period [23].

These factors combined will mean much greater system flexibility and higher hydrogen volumes from the stochastic input of wind energy. However, that (currently) comes at higher capital costs and a shorter median lifetime [20]. There are other advantages to a PEM stack especially for energy island conditions, such as the output of high pressure hydrogen from the production process [22].

Durability tests have found no significant performance losses over 5000 hours of intermittent operation, confirming the suitability of PEM stacks for use in conjunction with wind energy [21]. Performance degradation of PEM stacks has been attributed to two factors: the first are reversible processes such as incorporation of small amounts of metallic cations from the tubing into the membrane which may be limited by careful monitoring and combatted by O&M procedures. The second are irreversible processes, such as hot spot formation, which cause critical damage to the membrane and the electrolyser itself. This issue can be combatted again by monitoring, but will require the replacement of defective Membrane Electrode Assemblies (MEAs) at higher O&M costs [21]. Degradation costs of electrolysers are not taken into account in the analysis, and assumed to be indirectly absorbed in the lifetime of the stacks.

Future research is required on the possibility of utilising a higher operation pressure inside a PEM stack to generate the desired pressure rather than using post-production compression (the shore-side requirement for pressure is ~70bar, after pipeline pressure losses), as there are claims that an operational pressure of 350bar has been reached [22]. The increase in energy requirements to produce the same volume of hydrogen are significantly less than the energy requirements of an external compressor.

The largest currently available commercial PEM stack is 10MW [20]. However, the number of cells per stack seems invariant with size above 0.5MW, and the number of cells per system is therefore linear as stacks of 0.5MW are added to increase system size [20]. It may be assumed that with the large-scale proliferation of increasing capacities of PEM electrolysers to meet the demands of the growing hydrogen economy, a redesign of the PEM may occur with different cell characteristics and numbers of cell per stack, benefiting the cost price via economies of scale. Alternatively, with simple layering of stacks up to the GW scale will lead to reductions through the shared BOP between stacks (e.g. storage, dryers, water feed equipment etc.), and from economics of standardisation.

At present, the capital investment (some €1,000 to €2,000 per kW) needed for carbon-free hydrogen are too high to enable the product to compete with traditional hydrogen production.

However, most electrolyser technologies are still at the beginning of the learning curve. The underlying calculated learning rates for electrolyser technology show a slightly declining trend towards 2050, but range between 16.8% (2017) and 12% (2050) for PEM electrolysers [26]. To illustrate, 48% of the cost of the PEM stack (which itself is half of the total investment costs), are for flow fields and separator plates, and there is a significant learning-by-doing cost reduction possible with the advent on new separator materials to replace the very expensive titanium that is used currently

Hence, in actual practice electrolyser costs will come down more and probably faster than projected by these learning rates due to international competition and economics of scale. First, much larger electrolyser units will be introduced up to electrolysers at GW scale. Second if carbon-free hydrogen develops into a substantial part of the energy system of the future, the number of producers of electrolysers will obviously grow considerably and with it the degree of international competition. Last, the assembly line production method for PEM stacks is currently largely manual and has opportunities for significant cost saving through automation and robotics [20].

The total cost price of hydrogen production is (currently) dominated by the variable costs (60-70%), making them sensitive to variations beyond CAPEX costs, and placing major importance on the fuel costs (the electricity price) [27]. Because on average the additional CAPEX required for P2L conversion is relatively modest, also for P2L based products the electricity prices are crucially impacting on the cost price.

Desalination

A specific component that is imperative for electrolysis is the availability of demineralised water. Figure 9 highlights the demand for demineralized water in the various scenarios.

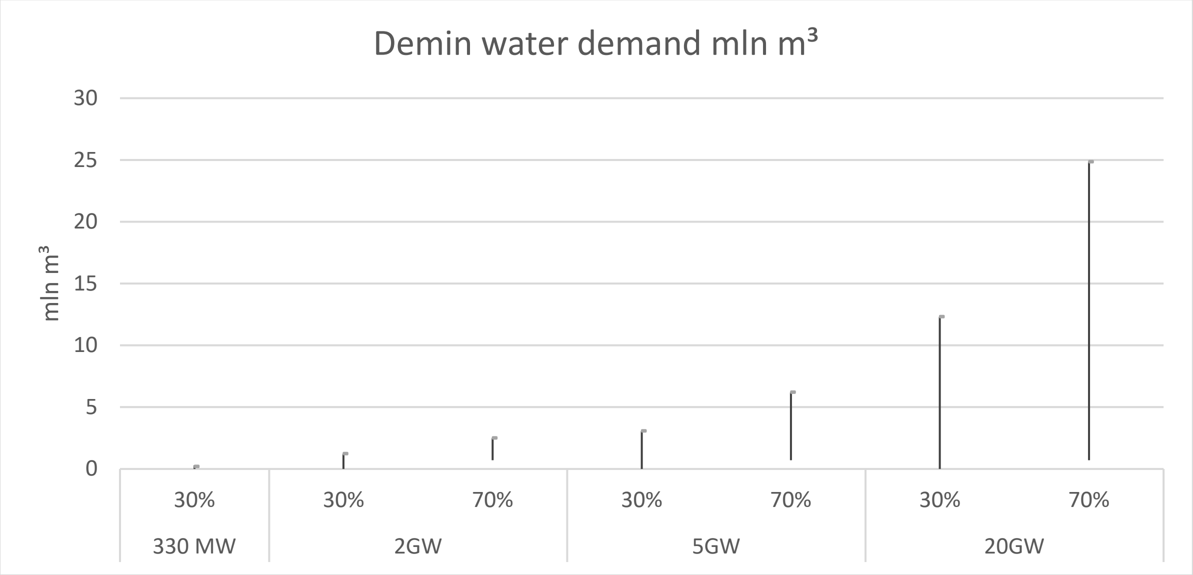

Figure 9: Demand for demi water in mln m³

On the bases of full load, some 2 to 25 million m³ of demi water would be required per year. This can be produced from sea water, but that requires a demineralisation unit. Usually, such units are not very large. More information on the various sub-processes is given in Appendix E. Desalination system. The focus is on large-scale uptake of seawater, and therefore the largest pre-treatment system, 100m³/h, has been used in the economic analysis. Although the reverse osmosis has high investment cost (some €3,500/kW), it has relatively low operational costs [24] e.g. due to the fact that energy is recovered by turbine or pressure exchanges. The largest capacity scale of LennRO SW and the BWRO-L require a power connection of some

280-360kW and 56kW, respectively [24]. Because large volumes of demi-water are needed in the electrolyser process and therefore onshore conventional water supply is insufficient, it has been assumed that a desalination unit needs to be installed at shore for the onshore P2H, P2M and P2A scenarios.

Compression

In a number of scenarios offshore hydrogen compression is a necessity. The highest pressure is requested for ammonia production (some 250 bar), followed by pressure for transport (some 50-60 bar), and ultimately also for the methanol process (some 50 bar). For each of the scenarios compression costs are included. For this purpose the compression power is calculated (Equation 3) determining together with the operating hours and the load profile the energy required for compression.

$$P = \frac{Q}{3600 * 24 * 33.33} \times \frac{Z \times T \times R}{M_{H_2} \times \eta_{comp}} \times \frac{N_\gamma}{\gamma - 1} \times \left[\left(\frac{P_{out}}{P_{in}} \right)^{\frac{\gamma-1}{N_\gamma}} - 1 \right]$$

Equation 3: compression power based on [29] & [30].

where:

- P the compression power (kW)
- Q the flow rate (in kWh per day) by taking a low heating value (LHV) of 33.33 kWh/kg specific to hydrogen
- P_{in} the inlet pressure of the compressor (suction)
- P_{out} the outlet pressure of the compressor (discharge)
- Z the hydrogen compressibility factor
- N the number of compressor stages
- T the inlet temperature of the compressor (278 K)
- γ the diatomic constant factor (1.4)
- M_{H2} the molecular mass of hydrogen (2.0158 g/mol)
- η_{comp} the compressor efficiency ratio (here taken as 75%)
- the universal constant of ideal gas R = 8.314 J K-1 mol-1

The CAPEX of compression is determined on the base of P required for the various scenarios. Capital costs of about €2,000/kW[16] are assumed. Operational expenses are assumed to consist of: 2% of the initial CAPEX p.a. and electricity costs based on compression power.

Pipeline transport of hydrogen and hydrogen booster

Pipeline transport of hydrogen can take multiple forms. In the most cost-optimal situation, the existing pipeline infrastructure can be used to transport pure hydrogen to shore. In the least cost-optimal situation a new dedicated hydrogen pipeline will be installed. Since the exact location, and thus the proximity of existing pipelines is unknown in our project boundaries, the conservative assumption has been used that new dedicated hydrogen pipelines will be needed.

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[16] Based on [30] while assuming an exchange rate of 1.20 EUR/USD (2017)

The pressure drop calculation tool (developed as part of WP 3.4[17]) is used to determine the size of the pipeline, its design and the inlet pressure. A number of constraints were defined for the calculations with this tool (see Table 7). The results (Table 8) show a major difference in the pipeline size required for the various cases.

Table 7: Model input for pressure drop calculation

Model input pressure drop calculation	Value
Output pressure (on shore)	30 bar
Admissible surface roughness new pipeline (epsilon)	0.05 mm
Temperature (deg. C. at inlet)	10 deg. C
Molecular weight	2.016 g/mol
Dynamic viscosity (Pa.s)	0.0000086
Velocity (m/s)	Between 10 and 20 m/s.
Mass flow rate (kg/h)	Variable input (dependable on the scenario)
Distance	Variable input (dependable on the scenario)
(Internal) Diameter (m)	Variable output (dependable on the scenario)
Pressure (bar) at inlet	Variable output (dependable on the scenario)

Table 8: Pipeline diameter and design (inlet) pressure for various scenarios

Case		Volumetric mass (kg/h) (input)	Distance (input)	Diameter (output)	Inlet pressure (bar)	Outlet pressure (bar)
330MW	30%	2,000	150km	6 inch	70	29
5GW	30%	29,000	150km	16 inch	60	30

High pressure hydrogen compression is a prerequisite for the transport of hydrogen to shore. Because of its lower molecular weight and viscosity, hydrogen flows move 2–2.5 times faster than natural gas in a pipeline under the same conditions of pipe diameter and pressure drop. However, because of the lower heating value of hydrogen, a hydrogen pipeline carries about 30%–40% less energy than a natural-gas pipeline. That is why hydrogen pipelines need to operate at higher pressures to supply the same amount of energy, or need to have a larger diameter [27]. Assuming that at the upstream end in each scenario (the production location) a PEM electrolyser will split the water molecules using offshore wind-power to produce the hydrogen, output pressure at the pipe inlet will be in the order of 30 barg. It is expected that due to technological innovation this may increase towards 60 barg [23]. Also, new developments are carried out to advance innovation of the High-Pressure Electrolysis (HPE), which is based on the PEM electrolysis, but with the difference that the compressed hydrogen output is around 120 to 200 bar at 70 ºC.

In each offshore scenario the hydrogen is compressed to satisfy the required downstream receiving pressures of at least 30 barg at shore. The input pressure varies between all of the scenarios as determined by the pressure drop calculation tool. The pressure drop occurring in the pipe due to friction when transporting hydrogen (or any other gas) depends on: the pipe diameter, the gas throughput, the surface properties of the pipe material, the velocity level in the pipe, and the density of the gas. At shore, an additional booster is assumed to increase the pressure from 30 to 68 bar making it comparable to the existing gas grid operating pressure.

The method to determine associated pipeline costs follows the series of estimations made by EBN and Gasunie in their report 'Transport en opslag van CO2 in Nederland' [9]. It states that on average, besides the pipeline material, two major factors are crucial for pipeline investments

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[17] This tool is available upon request to NSE

costs: the diameter and the distance to be covered. Generally put, costs per kilometre decrease as the distance increases. The report's estimates were based on market prices and globally realized projects; because market prices were quite low at the measurement moment (2017), the estimates are assumed to have accuracy ranges from -20 to +40%. Other factors that can have a prominent impact on the cost of laying new pipelines include: submarine obstacles (such as other pipes and cables), but also super-sea obstacles, such as platforms or wind farms. All this may require that crossings need to be implemented. It is assumed that special seals to minimize hydrogen leakages will require special labour (H2-specific welds), so labour expenditures are assumed to be some 25% higher [28]. Also pipes resisting hydrogen embrittlement will cost more than ordinary pipes (some 50%). Since, the existing right of ways will be used, a top-up cost factor of only 13% will be assumed.

The cost elements described above have been summarized in Table 9. Note that the hydrogen booster is applicable for both onshore and offshore. The primary compression is only assumed to be applied to transport the hydrogen to shore at a pressure of 30 bar. The compression costs in the onshore case are about 50% lower than those described in Table 9, and also the electrolyser system costs are expected to be about 12%(5GW scale) -16% (330MW scale) lower. The latter can be explained by the fact that, amongst others, installation will be cheaper at the mainland. For the other cost elements no major variance in cost-price exist between onshore and offshore production.

Table 9: Costs overview of hydrogen for the various offshore cases

Scenario	5 GW	330 GW
CAPEX electrolyser (M€)	1674	124
CAPEX compressors (M€)	42	3.1
CAPEX desalination unit (M€)	17.5	1.2
CAPEX Pipelines (M€)	113	113
Output pressure electrolyser	30 bar	
Efficiency (based on LHV)	65%	
Load factor electrolyser	79%	
Capacity hydrogen compressor (offshore)	9.4 MW	0.75 MW
Capacity Hydrogen booster (onshore)	11MW	0.75MW
Capacity desalination unit	1.3MW	0.1MW

Ammonia production process

The ammonia production process has been developed to a mature global process over the last century, mainly for the production of 'high-carbon' ammonia using natural gas as a resource and as an energy source. The process involves high temperature and compression to synthesize hydrogen and nitrogen molecules into ammonia supported by a catalyst. Ammonia is produced in an equilibrium reaction from the elements hydrogen and nitrogen according to Equation 4.

$$N_2 + 3H_2 \rightleftharpoons 2NH_3$$

Equation 4: Reaction equation ammonia

However, in this study it is assumed that reactants hydrogen and nitrogen are produced via water electrolysis and from the ambient air, respectively. Figure 10 gives a general overview of the process flow for power to ammonia (P2A). A more detailed overview is given in 'Appendix F. Detailed process flow of P2A (5GW case)'. In our study we consider three main steps of the total production process: air separation of nitrogen, admixture and pre-treatment of the feedstock, and the synthesis of ammonia. The reaction product's state of aggregation is gaseous. Required energy for e.g. compression is assumed to be full electric. The following subsections give an overview of the P2A process, the description of the considered off- and onshore cases in WP3.4, and the scaling of the spatial and power requirements considered.

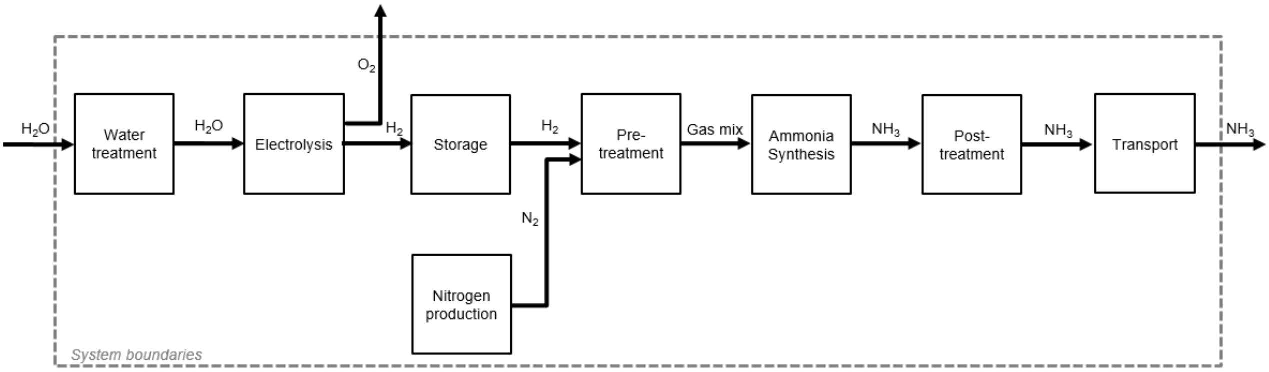

Figure 10: Simplified process flow for P2A production

Air separation of nitrogen

Nitrogen is considered to be freely available from the ambient air, which consists of 78% nitrogen. Due to the fact that the ammonia synthesis requires high purity educts, nitrogen has to be separated from other gases contained in the ambient air. The separation process is similar for off- and onshore cases as the consistency of air is constant on average. There are a few ways of air separation used in industry to separate pure CO_2, Oxygen, Nitrogen or Argon, but the most common ones are cryogenic air separation, membrane separation and pressure swing adsorption. Given the large scale of energy supply considered in this project, the last two options are ruled out since their nitrogen flow capacity is too low whereas cryogenic air separation is typically applicable in large industrial environments [4], [29]. Therefore, we assume the Air Separation Unit (ASU) to be based on cryogenic technology. The CAPEX of the ASU is just over €11M for a given daily capacity of 250 tons of N_2 [29].

The ASU consists mainly of a section for compression and drying the air, a distillation column, and a heat exchanger. By using the various boiling points of the elements in air, the nitrogen can be separated. The required energy source is mainly electricity for compression to approximately 8 bar; through expansion of the gas the temperature is decreased accordingly

(Joule-Thomson effect). The nitrogen gas is subsequently transported to the pre-treatment facility to be compressed and heated. During the cryogenic air separation process, oxygen is also separated from the air. However, its potential benefit is not further analysed.

Pre-treatment and admixing

The feed for ammonia needs to be compressed at pressure ranges between 100 and 250 bar and heated to temperatures between 300 °C and 550 °C depending on chosen catalyst material [2], [4]. Compressors and heat exchangers are assumed to bring the feed to the required pressure and temperature level. The mixed streams of compressed and heated nitrogen and hydrogen form the syngas which is the base for the synthesis. The total power requirement for the nitrogen compression is described by Equation 5, wherein the output of Equation 3 is used as the input for the relative fluid power requirement.

$$P = \frac{Relative\ fluid\ power\ requirement}{\eta_{compressor}\ \eta_{drive}}$$

Equation 5: Power requirement nitrogen compressor

where the adiabatic compressor efficiency ($\eta_{compressor}$) is 75% and the drive efficiency 90% [4].

Ammonia synthesis

Once pressurized, the syngas enters the synthesis loop where the equilibrium and reaction kinetics determine how much ammonia is produced per cycle. In the reactor there is a catalyst (e.g. iron oxide catalyst) increasing the speed of the exothermal reaction. Due to the exothermal nature of the reaction the compression has the largest energy demand of the synthesis. After one loop of the syngas the produced ammonia is continuously separated from the stream by condensing the gas. There usually are minor impurities in the feed (e.g. argon) which cause the catalyst to degrade, so these are purged from the mixture leaving unreacted feed gas in the loop. During one cycle through the loop approximately 20 – 30% of the syngas is converted to ammonia [4]. The condensed ammonia is stored under pressure or cryogenic conditions, before being shipped.

Compared to the requirements of the methanol feed, the feed for ammonia needs to be more compressed and heated. Typical pressure ranges are between 100 and 250 bar and temperatures between 300 °C and 550 °C, depending on chosen catalyst material [2] [4]. Compressors and heat exchangers are assumed to bring the feed to the required pressure and temperature level. To account for the compression energy that is required to bring the feed to the respective pressure level, the fluid compression work and subsequently the shaft compression work is calculated according to Equation 6 and Equation 7.

$$\dot{W}_{fluid} = T_{in} N \frac{n}{n-1} R M \left[\left[\left(\frac{P_2}{P_1}\right)^{\frac{1}{N}} \right]^{\left(\frac{n-1}{n}\right)} - 1 \right]$$

Equation 6: Calculation of the fluid compression power [29]

$$\dot{W}_{shaft} = \frac{\dot{W}_{fluid}}{\eta_{\iota}}$$

Equation 7: Calculation of actual power needed at the shaft [29]

The CAPEX of the compressor combined with the driver and subsequently the heat exchanger is about €10M and €3.5M for a pre-treatment plant with the daily capacity of 300 tons [29]. The equipment necessary for the actual ammonia synthesis consists of multiple pressure vessels that process the ammonia and other synthesis gases. Equipment that is reflected in the overall CAPEX comprises high pressure reactor vessels and flash drums (vapour-liquid separator). The total CAPEX is about €2.4 M for a synthesis process with a daily capacity of 300 ton NH3 [30]. The quality of the produced ammonia is assumed to be sufficient (99.5% purity) for transport to industrial sites [4]. Table 10 provides a comprehensive overview of the main parameters (incl. costs) of the PTA-process.

Table 10: Costs overview of ammonia for the various offshore cases

Scenario	5 GW	330 GW
CAPEX ASU (M€)	28.2	4.6
CAPEX compressors (M€)	63	4.2
CAPEX synthesis (M€)	93	15
Back-up power (GWh)	669	44
Grid energy costs (M€)	33.4	2.2
Input pressure synthesizer	250 bar [2] [4].	
Load factor electrolyser	83%	
Efficiency (based on LHV)	56%	
Capacity hydrogen compressor	28 MW	1.8 MW
Capacity nitrogen compressor	5.3 MW	0.35 MW

Methanol production process

Methanol is a chemical product that is mainly used as a resource to produce a variety of other chemicals, but is also used as a solvent for paints and plastics. Methanol is in a liquid state at ambient pressure and temperature which makes it easier to store and transport in comparison to hydrogen [16]. The methanol production process has been developed to a mature global process over the last century. The process involves relatively low temperature (250°C) and 50 bar compression [31] to synthesize hydrogen and carbon molecules to methanol supported by a catalyst. Methanol is produced in an equilibrium reaction from the elements hydrogen and carbon according to Equation 8.**Error! Reference source not found.** Assuming optimal reaction conditions with a molar ratio CO_2 to H_2 of 1:3 the product of the synthesis reaction is methanol and water.

$$3H_2 + CO_2 \rightarrow CH_3OH + H_2O; \text{ exothermic}$$

Equation 8: Optimal reaction equation for methanol

wherein the required hydrogen is assumed to be produced via water electrolysis, and CO_2 is to be transported from shore via a pipeline. Figure 11 gives a general overview of the process flow for power to methanol (P2M). A detailed overview is given in 'Appendix G. Detailed process flow of P2M (5GW case)'. In our study we consider three main steps of the total production process: pre-treatment, methanol synthesis, and post-treatment. The reaction product's state of aggregation is liquid. Required energy for e.g. compression is assumed to be full electric.

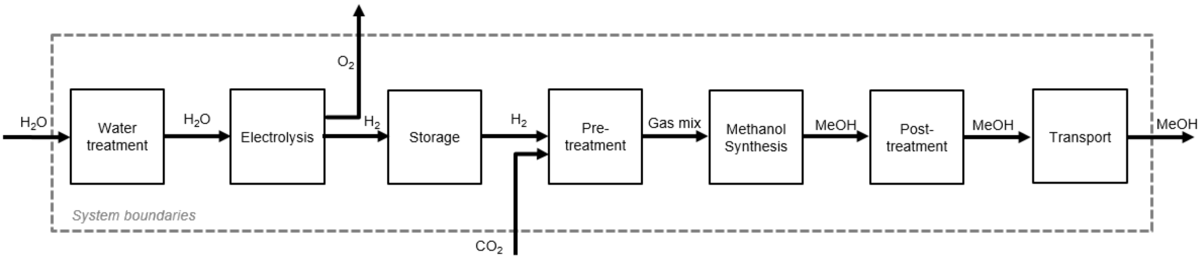

Figure 11: Simplified process flow for P2M production

The feedstock for typical methanol production is a fossil fuel, mostly natural gas. However, 'carbon-free' methanol, the focus of this project, can be made from renewable sources such as wood, municipal solid waste and renewable electricity together with CO_2 .

Pre-treatment of the feedstock

Before the actual reaction takes place, both educts CO_2 and H_2 need to be compressed and heated to meet the optimal reaction conditions. The pressure levels and required temperatures depend mainly on the catalyst that is used for the synthesis process. In the case of methanol, pressure levels of around 50 bar and temperatures between 230°C and 280°C are common [2], [32]. Within this study, we assume that the preheating of the feed can be achieved by reusing heat which is released during the reaction [36] [33]. To account for the compression energy that is required to bring the feed to the respective pressure level, the fluid compression work and subsequently the shaft compression work is calculated according to Equation 6 and Equation 7

Methanol synthesis and distillation

The feed output of the pre-treatment step is directed towards a reactor where both educts react to methanol over a catalyst. According to the pressure and temperature requirements that have been specified in the previous section, the catalyst considered is a commercial $Cu/ZnO/Al_2O_3$ catalyst. The reaction takes place under exothermic conditions and the released heat (about 2.01 kWh/kmol) can be reused for the pre-treatment step [33]. Keeping in mind the other excessive heat flows of e.g. the electrolysers in the system, it has been assumed that no additional heating is required. The relevant parameters for this process are shown in

Table 11. A sufficient product quality with methanol purity levels above 99% can be achieved when water and other by-products such as higher alcohols are removed by distillation of the reaction product stream. This can be done by passing the product stream through multiple distillation columns under heat supply.

This study assumed CO_2 to be available at the production location against zero costs (both for infrastructure as well as power input). To still be able to make a fair comparison between on- and offshore methanol production, a sensitivity analysis is included to account for offshore related costs for CO_2 transport/utilisation in the range of €-30 to €30 per ton of CO_2 transported. The efficiency of the methanol process is probably slightly overestimated, due to a synthesis process with low compression requirements and because no energy consumption is assumed for the CO_2 feed.

Table 11: Costs overview of methanol for the various offshore cases

Scenario	5 GW	330 MW
CAPEX compressor (M€)	1.6	0.3
CAPEX distillation (M€)	18	3
CAPEX reactor (M€)	133	21
Back-up power (GWh)	1895	125
Grid energy costs (M€/year)	94.8	6.3
Input pressure synthesizer	50 bar [2] [32]	
Efficiency (based on LHV of 5.54kWh/kg)	74%	
Load factor electrolyser	93%	
Power requirement hydrogen	2.1MW	0.14MW
CO_2 infrastructure (M€)	0	0
CO_2 power requirement	0 MW	0MW

Post-treatment of the product

A sufficient product quality with methanol purity levels above 99% can be achieved when water and other by-products such higher alcohols are removed by distillation. The distillation requires some 9.83 kWh/kmol of heat infeed [33].

Shipping

The main advantage of shipping is the flexibility it offers by the ability to transport the energy to the global market rather than be bounded to a certain landing point. Global market access may be of great importance especially in the phase of underdeveloped markets for carbon-free chemicals. Shipping solutions can be rather expensive, though. In this study, both the CAPEX and OPEX of shipping have therefore been taken into account, but not the additional costs related to harbour facilities.

Transport of ammonia can either be liquid or pressured. Ammonia released from the synthesis process at 10 bar could be transported via pressurized ships. Ammonia can also be liquefied via cryogenic storage to -33°C. Both, cargo handling costs and the distance of transport are important to the total costs of shipping. For both, ammonia and methanol transport, the model provided by [34] as suggested by [41] has been used. The costs for ammonia transport by ship are modelled on the basis of the Bu Sidra LPG tanker [36]. This very large gas carrier (VLGC) has a carrying capacity of 50,000–80,000m^3 and costs approximately €64M.The costs for methanol transport are based on a chemical tanker (e.g. Canjun Sun or Manchac sun [37]) with total capital costs of €44M. Data for small-scale shipping is retrieved from Delta Marine for small-scale LPG[18] and small-scale chemical tanker[19]. It is assumed that the latter cost about 1/5 of the cost of the mentioned VLGC's. Apart from the OPEX (about €7850/d), a cost accounting had to be made for fuel costs and harbour fees.[20] The distance considered is 150 km one-way.

A possible transport model is proposed in Table 12, where the constraint is assumed to be the platform storage capacity (1 to 2 days of production, next paragraph). Therefore, the ships used for the small-scale production systems can, at least in theory, be used as a mobile 11-day production storage facility. In the case of islands, economics will tell how often ships of various sizes will sail out to take up the product depending on the (generally less restricted) storage capacity available on the island.

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[18] http://www.deltamarine.com.tr/pdf/products/Merchant%20Ships/LPG%20Carrier-3500CBM.pdf

[19] http://www.deltamarine.com.tr/pdf/products/Merchant%20Ships/Oil%20Chemical%20Tanker-3500DWT-2.pdf

Table 12: Overview of shipping costs for 330MW and 5GW P2L scenarios (based on [34])

Cargo handling	Ammonia Small - Delta Marine based)	Ammonia (Bu Sidra based)	Methanol (Small - Delta Marine Based)	Methanol (Canjun Sun)
Production (ton/year)	80.000	1.215.000	300.000	1.665.000
CAPEX (€)	12.800.000[21]	64.000.000	8.800.000[22]	44.000.000
Max. cargo capacity (in ton)	2750	45.500	3365	45.000
Duration of loading (days)	11	1	10	1
Min. roundtrip travel time (days)[23]	1.5	1.5	1.4	1.5
Port costs M€	24.000	887.800	32.800	1.126.000
OPEX journey (€)	412.000	311.700	412.000	434.600
Fuel consumption costs (€)[24]	325.000	270.300	277.200	347.000

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[21] No information was available on the investment cost for the smaller scale LPG tanker. It has been assumed that CAPEX is 1/5 of the Bu Sidra.

[22] No information was available on the investment cost for the smaller scale oil and chemical tanker. It has been assumed that CAPEX is 1/5 of the larger Canjun Sun tanker.

[23] It is assumed that the ship will be for 3 days in the incoming and outgoing harbour. Distance is set at 150 km or 81NM.

[24] Based on Price of fuel oil of 360€/t and fuel consumption of 32ton/day (only during journey).

Spatial requirements for P2X

The production of P2X on an offshore location requires a substructure, either platform or island, that will be able to offer the needed multitude of functionalities. In all scenarios the substructure should be able to host the electrolyser package (converter station, desalination unit, electrolyser and compression), a helicopter platform, a cable landing zone and accommodation. Apart from the scenario chosen, additional space could be dedicated to a harbour or refuelling, bunker and waste station, ammonia and/or methanol production equipment and assembly space. 'Deliverable 3.8 offshore energy islands' provides an in-depth insight on the sizing considerations of the various types of islands. Taking into account the total P2X system, some 7550 m^2 of surface per 100 MW of electrolyser capacity would be required.[25] Additional space has to be reserved for the integration of the electric system. Taking into account a 220kV HVAC system, an additional 2100m² will be required, bringing the total to 9650m². Table 13 shows the volume, mass and area taken into consideration for our cost estimations; for the sake of comparison also the more optimistic figures used in a study by DNV GL have been included.[26] [27]

Table 13: Data input for a 100 MW electrolyser on a platform (jacket related estimates assume values to increase in proportion with jacket mass)

Item	Sub-item	Report input per 100 MW	100 MW reference case [38]
Topside	Total mass of hydrogen production plant (tons)	1,280	1,280
	Estimated topside volume (m³)	36,200	19,355
	Estimated mass of supporting Steelwork (tons)	2,650	1,325
	Rooms and cladding (m²)	660	660
	Gratings (m²)	4.258	2,129
	Estimated coating area (m²)	50,580	25,290
Pile	Pile Mass and Structure (tons)	1082	541
Jacket	Estimated Jacket Mass (tons)	2622	1311
	Secondary steel estimation (tons)	182	91
	Anode estimation (tons)*	32	20
	Coating area estimation (m²)*	3393	1966

A 100 MW carrying platform for power-to-hydrogen, see Figure 12, costs about 30 million euro in terms of CAPEX (i.e. 300k€/MW). Note that in the case that an existing jacket and pile would be re-used and the topside redesigned, CAPEX would reduce to about 200k€/MW (topside

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[25] We assume here that economies of scale are hard to be realised on a platform. A 2GW island with a some 600MW of electrolysers requires some 45.250m². Hence, a 30% conversion on a platform would require some 7550m² for the conversion process (incl. step-down voltage levels, desalination, electrolysers and compression).

[26] Note that in another, quite detailed, assessment of the service area required for offshore P2X carried out by DNV GL [38], a much lower value was arrived at. If that source would be used the surface requirement would be about half the level assumed in this report. Our surface requirement assumption derived from 'Deliverable 3.8 offshore energy islands' therefore can be considered to be quite conservative in the sense that the (expected) more compact electrolyser units have not yet been taken into account. The surface requirement of a HVAC station is also based on surface requirement used to in D. 3.8 Offshore Energy Islands.

[27] The study had not taking into account the additional weight of the power-to-x process, which may lead to a larger platform configurations.

costs + installation). For the substructure cost of installing electrolysers on an island, see 'Deliverable 3.8 Offshore energy island'.

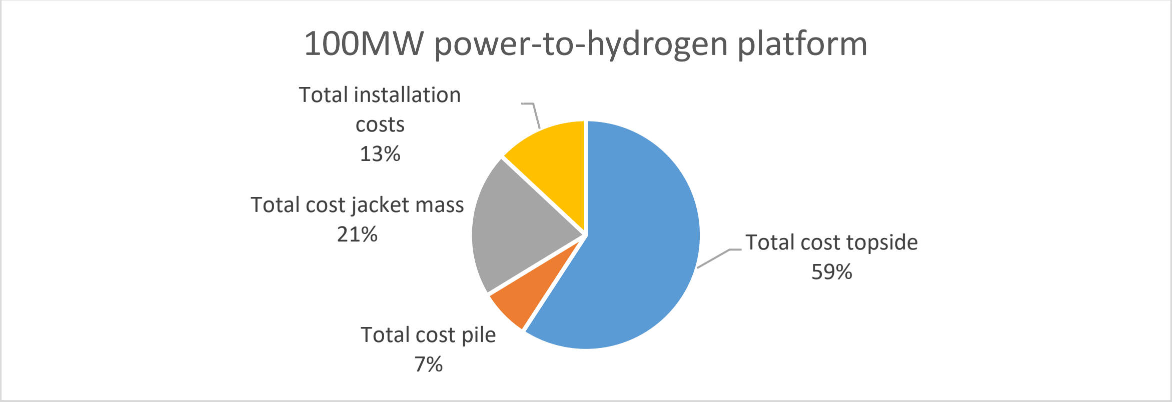

Figure 12: Capital investment distribution of a 100 MW power-to-hydrogen

Size requirements for P2A

In some specific circumstances the economics of small-scale 'carbon-free' ammonia production maybe interesting, especially if one has easy access to carbon-free hydrogen. Small-scale ammonia production currently takes place in the capacity range from 1 to 100MW [15]. A 100MW plant, usually consisting of 5 20MW stacks, is able to produce some 300 tons/day. The production process of such a plant is, although small-scale, still based on the Haber-Bosch technology. This technology is focused on continuous production with a flexibility of 70%-100%, although small-scale systems are able to work in the flexibility range of 30%-100%, making the need for back-up capacity much smaller. It is expected that similar flexibility could be realised by larger facilities, but that this will requires a different engineering approach.

Table 14 gives an overview of the spatial requirements for both a small-scale (in this case with an assumed production of 220 tons/day) and large-scale (3,330 tons/day) production facility. The data are based on the 100 MW facility. Since this facility consists of modular stacking facilities it is assumed that size increases/decreases linearly with the scale of production. The synthesis process is located in 2x40ft[28] containers whereby one container is placed vertically and one horizontally. The Air Separation Unit consist of multiple skids and the dimensions are highly dependent on the systems applied. The latter can either be a BSA system (compact, high energy use), or a cryogenic system (complex with higher dimensions). The 60 ton/day stack system consists of a cryogenic air capture system as purity is crucial (decreases the risk of oxygen poisoning of the catalyst). The compressor dimensions (incl. cooling) strongly depend on the number of compressor stages.

Table 14: Dimensions of various sub-components of the ammonia process for small-scale and large-scale facilities

Specification	Small scale (m^2)	Large scale (m^2)

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[28] A standard 40ft container is 12.2m. x 2.44m x 2.59 m.

Synthesis process (based on [15] [29][29]	178,5	1000
Cryogenic air capture (based on [29][30]	26,2	100
Compression of hydrogen (based on D. 3.8 Offshore Energy Island)	110	1673
Compression of nitrogen (based on D. 3.8 Offshore Energy Island)	21	318
Ammonia storage [39][31]	50	2570
Total	385,7	5.661

Small-scale P2A facility

Total production in the small-scale facility modelled in this project is 220 tons/day (75% of the capacity of the reference case of 300tons/day). Table 14 gives an overview of its the spatial requirements. If an ammonia processor is also installed on the platform, in addition to the electrolyser, a total spatial requirement of 10,000m^2 results.[32] Given the small space required for the P2A facility it is assumed that adding this will not lead to higher platform structure costs.

If ammonia production may create issues related to weight and/or the height of the distillation columns has been left outside the scope of the project. Neither the issue of optimal ammonia storage facilities that may be needed to reduce shipping frequencies, nor dedicated offshore platform docking facilities for ships, has extensively been worked out in this report. Offshore ammonia storage on platforms or on floating constructions next to platforms may be interesting or even unavoidable options because the alternative, very regular if not daily shipping to take up the ammonia produced, may not be feasible in practice if only due to weather conditions.

Large-scale P2A facility

Production volumes of ammonia in the assessed large-scale facility, by definition located on an island, is assumed to amount to 3330 tons/day (Table 14). Such a facility requires 5GW wind capacity to generate the power required (assuming 30% of the energy will be available for electrolysers). The required (found in D3.8.) surface space of such a dedicated (i.e. suitable for dealing with a 5GW wind farm energy transmission) artificial energy island is about 430.000m^2. The total surface area required for the additional ammonia production facility is relatively small (some 5662m^2 only), so that in our modelling no surface adjustments have been made.[33] This is not to say that no additional costs will evolve from the ammonia plant in terms of making the plant area on the area suitable for construction e.g. due to an increase of sand/fill size against a cost of 7.5 €/m^3,, and an increase in revetment (for details see Appendix H. In total these additional costs accumulate to some €2M with an assumed safety margin of 20%. Contrary to the small-scale ammonia production facility on a platform, the issues concerning: height of the columns, storage requirements, and docking of ships, are now assumed negligible.

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[29] Much is unknown about the area required for a large scale synthesis reactor, so an average is taken for the installed area requirements from 60tons/day (small scale) and a 500 tons/day synthesis reactor (uninstalled). Economies of scale are expected at the large scale.

[30] The production of 300tons of ammonia requires 8900Nm^3 of pure nitrogen. This nitrogen is produced cryogenic via three columns with the following dimensions: 2,44Øm x 28.84m, 2,25Øm x 44.09m, 0,62Øm x 74.59m

[31] The ammonia could be stored in bunkers with a dimension of 8Ø*28m. This storage satisfies a daily storage for the small ammonia production facility of 220 ton (322 m3). For platforms 12,5m^2 per level is considered, with 4 levels in total. The ammonia on large scale could be bunkered in storage tanks of 52Ø*31m. This volume satisfies a 13.5 days storage.

[32] The total spatial requirement for the 100MW electrolyser (incl. related equipment) is 9650m^2.

[33] The 5GW hydrogen scenario from D3.8 assumes a spare surface area of 90.000m^2 of the total 430.000 m^2 surface area of the island.

Size requirements for P2M

Little literature is available on the dimensions of a typical methanol production facility. An expert interview has been conducted to determine the dimensions of the required facilities [21]. Based on this two existing Power-to-Methanol (P2M) facilities have been assessed, the 1200 ton/day BioMCN facility in Delfzijl (Netherlands), and the 7,000 ton/day Kaveh facility in Bandar Deyr, Iran, in order to get a better perspective of spatial requirements (to illustrate, the yellow lines in Figure 13 highlight the process equipment for P2M production).

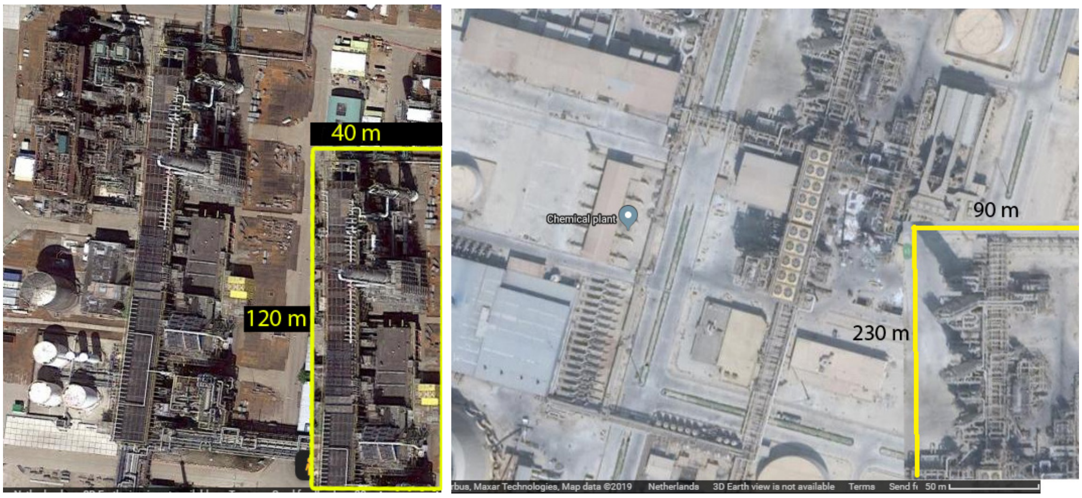

Figure 13: P2Methanol plants in Delfzijl (left) and Bandar Deyr (right)

Small-scale P2M facility (platform)

The total platform surface area required for a typical small-scale or 300 tons/day production P2M facility amounts to some 1,250m², if storage facilities are included assuming that the methanol could be stored daily in bunkers with a dimension of 8Øm by 30m. For methanol storage on platforms it has therefore been assumed that 12,5m^2 per level is required, with 4 levels in total. So given this small size in actual practice with regard to storage space there seem to be hardly any limitations; there are however still some additional platform structure and possibly docking costs. In total additional costs related to the methanol production facility were estimated to be about 1.4M€. As far as the other aspects (storage, docking, etc.) is concerned, the reader is referred to the small-scale offshore ammonia case discussed before.

Large-scale P2M facility (island)

The surface area required for a complete large-scale methanol facility (i.e. producing 4500 tonnes/day) amounts to 13,500m². Because the overall surface area of the island is assumed to be some 430,000 m^2, the methanol plant, even if it is large-scale, is assumed not to require any adjustments in the surface area of the island. Just like in the ammonia case, there will be some additional costs for preparing the ground work which are assumed to amount to €4M in total (20% safety margin). The methanol produced could be bunkered in storage tanks of 8.2Øm by 27.5m if so, this volume would store 9 days of production.

Techno-economics of P2X options

This chapter provides an overview of the outcomes of the techno-economic analysis for Power-to-Hydrogen, Power-to-Ammonia and Power-to-Methanol. Sensitivity analysis have been performed to all energy carriers with respect to the commodity prices and the investment costs.

Table 15 provides an overview of the main general input parameters that are used throughout the various cases. Appendix I. NPV datatable provides an extensive overview of the main outcomes incl. the volumes of the various energy flows. The outcomes of the LCOE analysis are given in Appendix J. LCOE . When interpreting the LCOE outcomes one should have a clear understanding of the allocation of costs to the molecular and electric system. These allocation principles are explained in the same appendix. These principles do, however, not affect the NPV as the NPV outcomes comprise both the cost and revenues for the electric and the molecular system.

Table 15: Main input parameters

Main parameter assumption	Value	Main Price assumption	Value
WACC	10%	Electricity price	50€/MWh
Load factor offshore wind	63.2%	Hydrogen price	2€/kg
Investment period	2 years	Ammonia price	300€/ton
Operational period	40 years	Methanol price	300€/ton
Offshore cost factor	1		

Power-to-Hydrogen

The NPV analysis gives a clear comparison of total system value of the various scenarios as it includes all costs and benefits of the electric and molecular system. Under the assumptions described in the previous chapters, the NPV for large scale hydrogen production in positive (and rather similar) for onshore and offshore production (see Figure 14) however, small scale hydrogen production shows a negative NPV outcome. This indicates that conversion at the island scale is economically most promising due to economics of scale that may be applicable. In both scenarios, hydrogen production seems, though with a minor difference, economically just preferable at an onshore location.

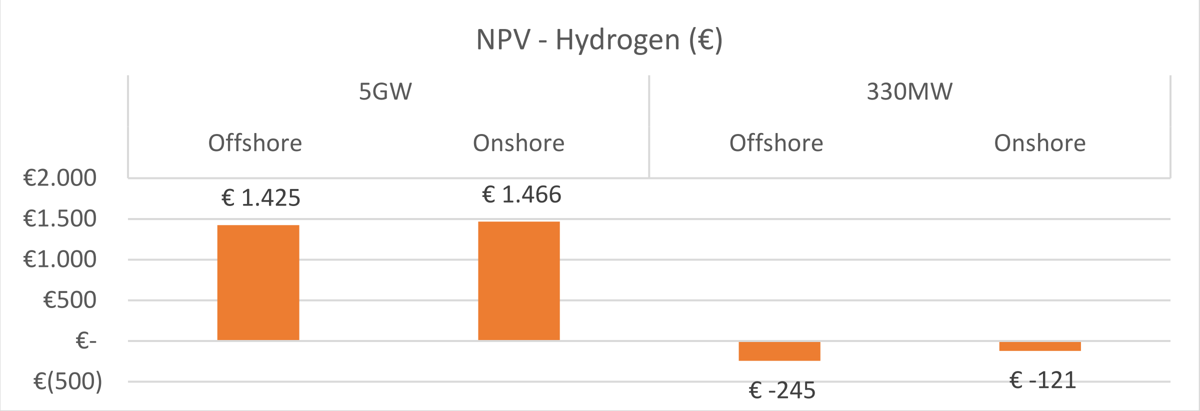

Figure 14: NPV of various H_2 scenarios in million euros

The marginal cost price of carbon-free hydrogen under the conservative base case assumptions, which relate more or less to the current situation, is €2.45/kg.[34] This is above the current market price for high-carbon hydrogen, which is in the order of €2/kg. The electrolysis costs highly affect the investment structure of the power-to-hydrogen scenarios. This is illustrated by Figure 15, highlighting the main elements of the CAPEX structure of the 5 GW hydrogen scenarios. The costs share of hydrogen production is noteworthy as it covers about 42% of the total investment costs. The current island scenarios only include new pipeline solutions for the transport of hydrogen, as the exact location of the energy island is (yet) unknown. A new hydrogen pipeline contributes (only) to about 3% of the total system costs. The structure costs of the energy island only comprise 19% of the overall investment costs.

Some general remarks with regard to the CAPEX distribution of the other scenarios are:

- Structure costs decline relatively if wind capacity/distance increases or if the proportion of molecules increases.
- Electric costs increase relatively if wind capacity/distance increase and decreases if the proportion of molecules increases.
- Pipeline costs decline relatively if the proportion of molecules decreases, but an increase in wind capacity/distance seems to have a neutral effect. This might be explained by the (yet) small contribution of pipelines (incl. compression) to the overall costs.

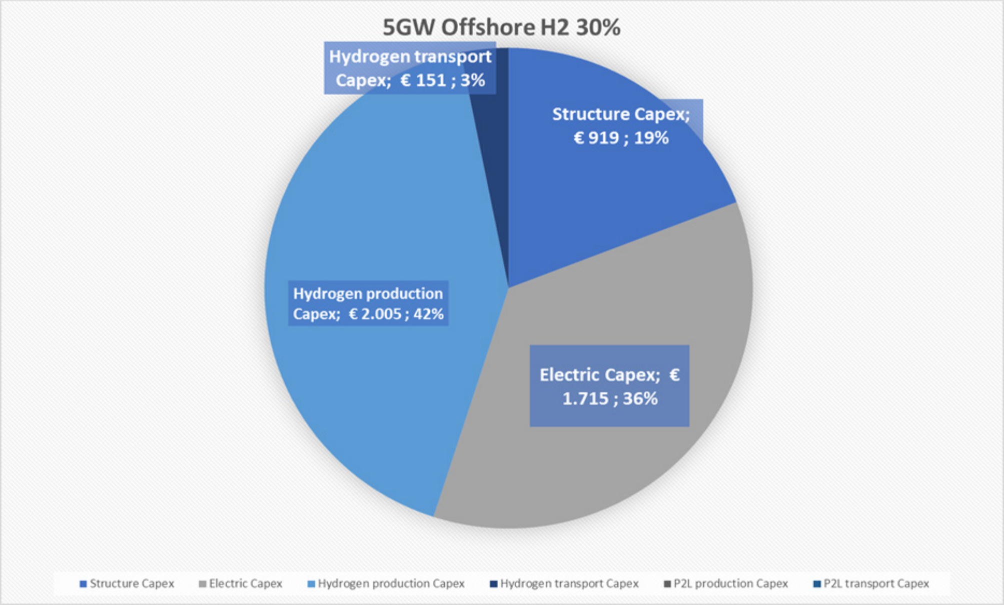

Figure 15: CAPEX distribution of the 5 GW hydrogen scenario (in million euros)

Power-to-Ammonia

The NPV outcomes are just positive (±€165Meuro) for all 5 GW cases, but negative for all 330MW cases (see Figure 16) this is in line with the NPV of the power-to-hydrogen variants. It should be noted that with the inclusion of the infrastructure cost for loading the NPV outcomes of the 5GW cases might just turn negative. The NPV outcomes of ammonia are in perspective

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[34] In the base case we assume an efficiency of 49kWh/kg and an electricity price of €50MWh a marginal cost price of green hydrogen of €2.45kg could be realised.

to hydrogen less positive / more negative. The previous section has shown, that under the base assumptions, the marginal cost price for hydrogen production outweigh the market price of €2/kg. Moreover, back-up power for additional hydrogen production is consider to ensure a more continuous production for the Habor-Bosch process. This leads to an increase in the total operational costs, given that marginal costs are higher than the market price for hydrogen. Next to that, a discrepancy between the marginal cost price for ammonia and its market price (300€/ton) persist, which contributes to a NPV outcome that is more negative than power-to-hydrogen under the applied assumptions.

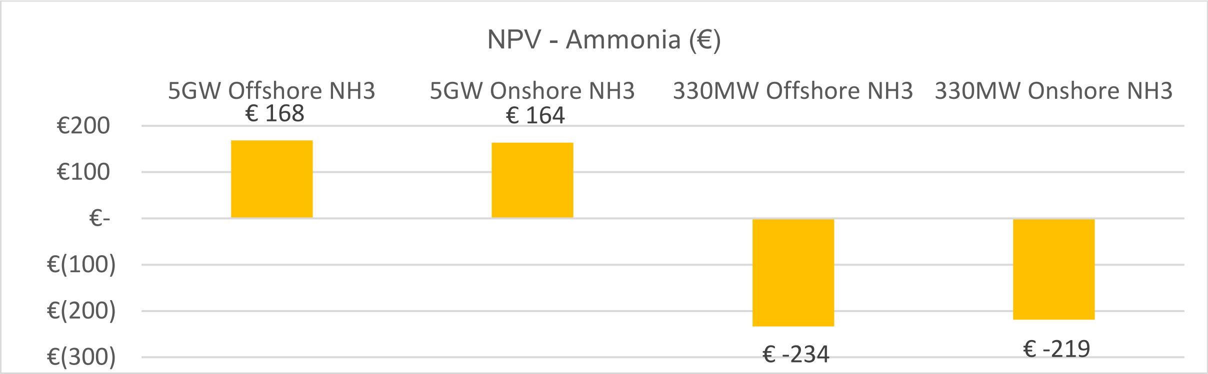

Figure 16: NPV of various NH_3 scenarios in million euros

The electrolysis costs also highly affect the investment structure of the power-to-ammonia scenarios. This is illustrated by Figure 17, highlighting the main elements of the CAPEX structure of the large scale 5 GW ammonia scenario. The costs share of hydrogen production is noteworthy as it covers about 41% of the total investment costs. The process equipment (incl. shipping) accumulates only to 4% of the total investment costs.

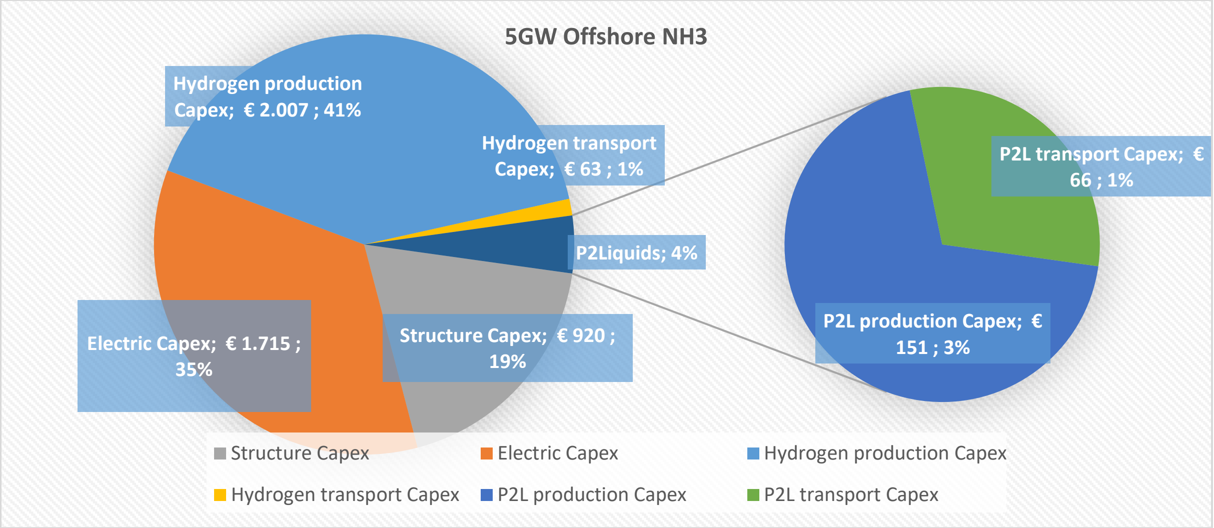

Figure 17: CAPEX distribution of the 5 GW ammonia scenario (in million euros)

Power-to-Methanol

The NPV outcomes are just positive (±€225 and ±310Meuro) for all 5 GW cases, but negative for all 330MW cases (see Figure 18), this is in line with the NPV of the other power-to-x variants. Also here, not all infrastructure cost were included, so the NPV might be a bit lower in reality. The NPV outcomes of methanol are in perspective to hydrogen less positive / more negative. The Power-to-Hydrogen section has shown that under the base assumptions the marginal cost price for carbon-free hydrogen production outweighs the high-carbon hydrogen market price. It should be noted that back-up power for additional hydrogen production is crucial in ensuring a continuous production for the methanol production process. The related increase in costs is to be covered by an increase in revenue from extra methanol returns. Methanol seems economically more feasible at an offshore location, though, what is not yet considered is the shipment cost that the methanol producer has to pay for the shipment of CO_2 sources to the island. A sensitivity in Appendix I shows that the NPV of the offshore 5GW methanol case decreases with 175 million euro for every 10€/tonneCO_2 increase in CO_2 utilisation cost.

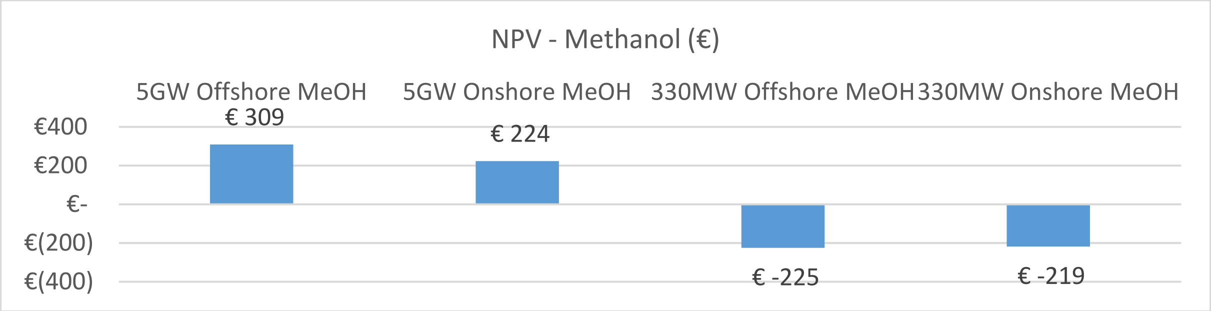

Figure 18: NPV of various MeOH scenarios in million euros

The electrolysis costs also highly affect the investment structure of the power-to-methanol scenarios. This is illustrated by Figure 19, highlighting the main elements of the CAPEX structure of the 5 GW-Offshore methanol scenario. The costs share of hydrogen production is noteworthy as it covers about 41% of the total investment costs. The process equipment (incl. shipping) only accumulates to 5% of the investments costs.

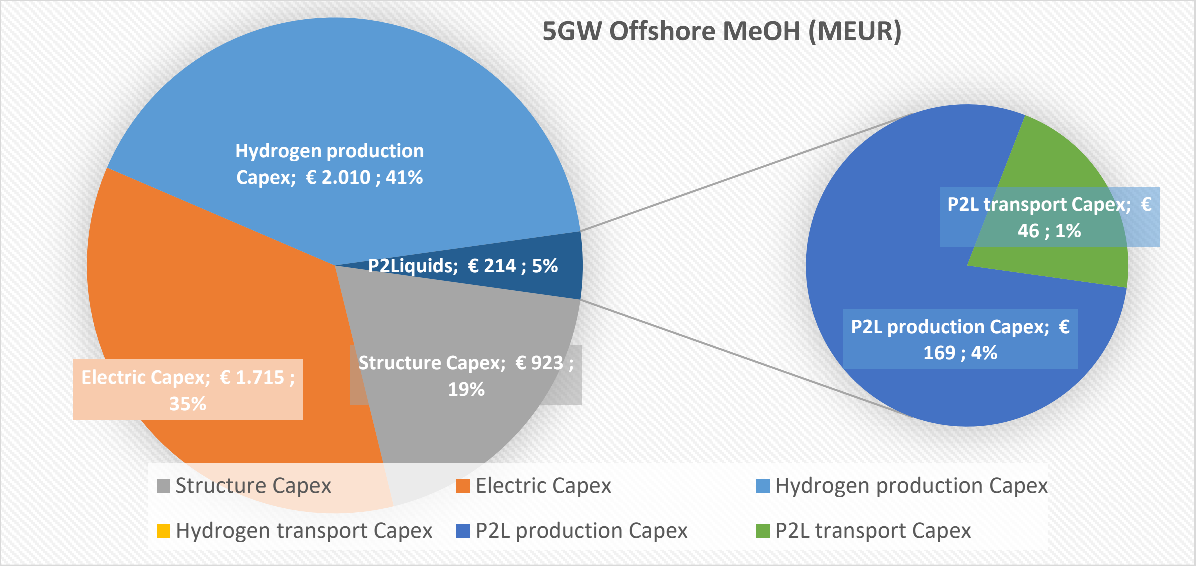

Figure 19: CAPEX distribution of the 5 GW methanol scenario (in million euros)

Sensitivity analysis

A sensitivity analysis is carried out to determine the effect of uncertainty of some parameters on the economic potential of P2X. Table 16 provides an overview of the parameters considered within the sensitivity analysis, their value in the base case, and the values used within the sensitivity analysis.

Table 16: Overview of sensitivity parameters

Parameter	Base case	Sensitivity analysis
Electrolyser costs	100%	+50% and -50%
Offshore costs factor	Onshore	1, 1.5, and 2.5
Electricity price	50 €/kWh	25 and 85 €/kWh
Hydrogen price	2 €/kg	1-6 €/kg
Ammonia price	300 €/ton	200-900 €/ton
Methanol price	300 €/ton	200-900 €ton

Electrolyser costs

Although electrolysis technology develops fast, much uncertainty exists about its cost development. Current learning rates for electrolyser technology show a slightly declining trend towards 2050 by ranges between 16.8% (2017) and 12% (2050) for PEM electrolysers (Böhm 2018). In actual practice electrolyser costs might come down more and probably faster than projected, due to international competition and economics of scale. Nevertheless, the electrolyser costs comprise a large proportion of the overall investment costs (as seen in Figure 15, Figure 17, and Figure 19). A sensitivity of -50% and +50% on the electrolyser costs is applied to analyse the impact of its cost reduction on the overall potential of P2X The outcomes for hydrogen, ammonia and methanol cases are shown in Figure 20, Figure 21, and Figure 22.

A decrease in the electrolyser costs by 50% will lead to an improvement of the NPV outcome of the 5GW cases in all power-to-x scenarios by some €1.2bln. The effect of technology development on the economic potential of smaller-scale hydrogen production seems to be less profound. A decrease in the electrolyser costs by 50% will not lead to a positive NPV outcome of the 330MW in either of the P2X scenario’s. The onshore variant is less affected by an increase/decrease in the investment costs of an electrolyser, as the share of the electrolyser costs in the total cost structure is a bit smaller than in the offshore variant. This is due to the fact that the total cost for the required electricity infrastructure are higher for the onshore production scenarios.

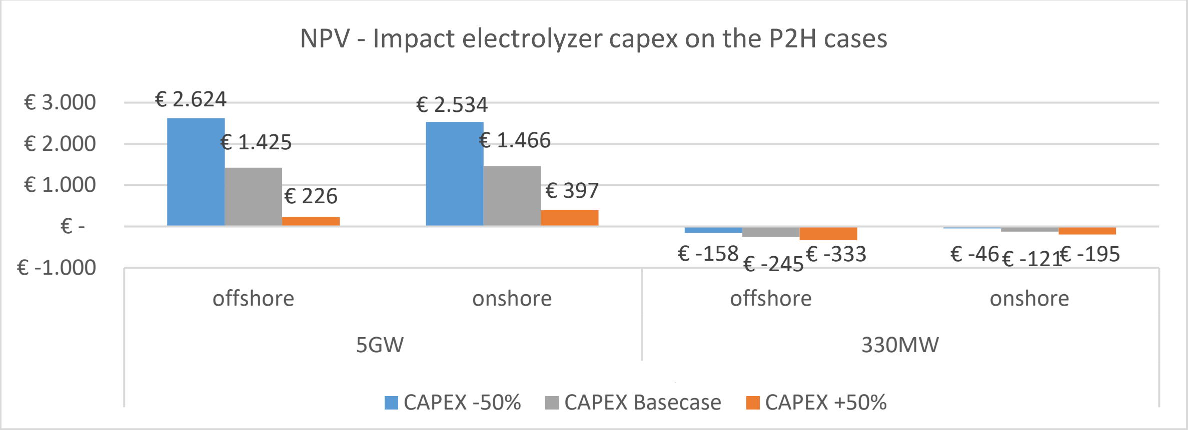

Figure 20: impact of electrolyser CAPEX on the NPV of hydrogen cases (in million euros)

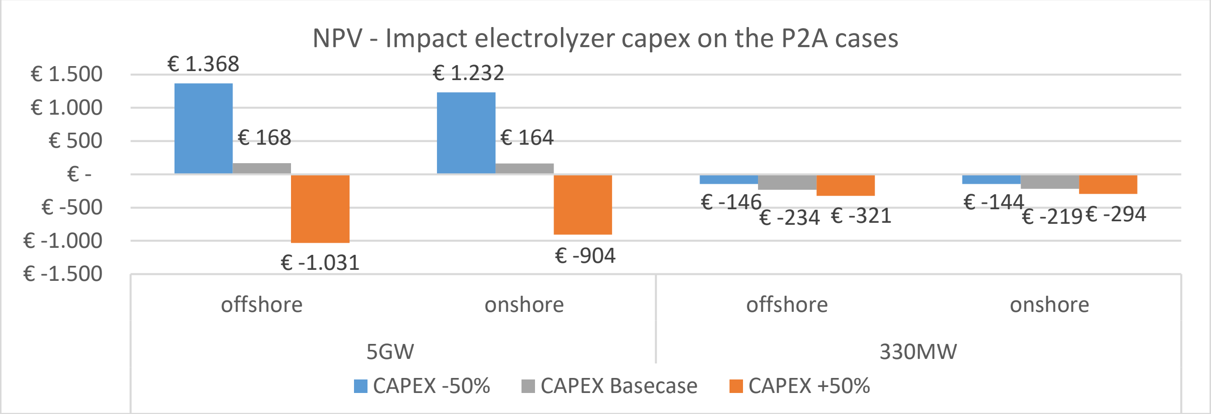

Figure 21: impact of electrolyser CAPEX on the NPV of ammonia cases (in million euros)

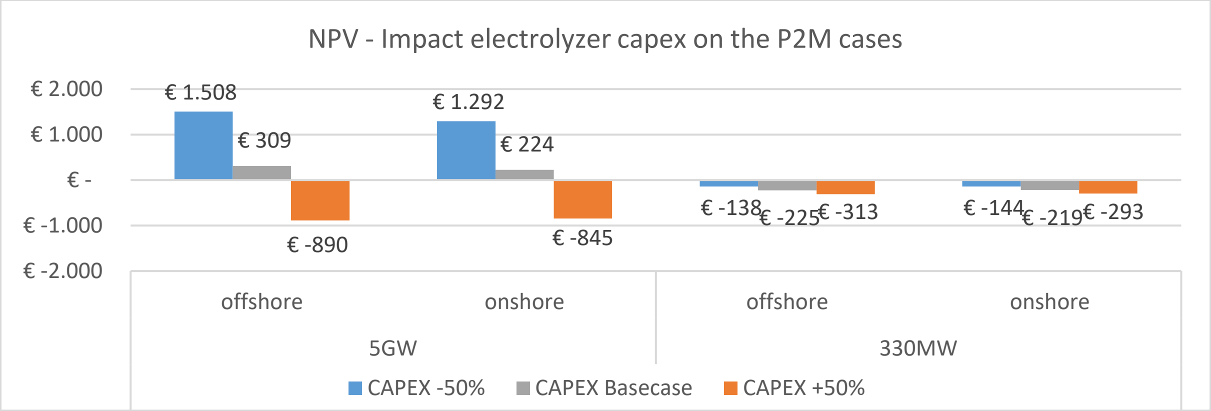

Figure 22: impact of electrolyser CAPEX on the NPV of methanol cases (in million euros)

Offshore cost factor

The base cases do not consider any additional cost for offshore production in comparison to onshore production of hydrogen. However, given different environmental circumstances as well as a likely increase in installation costs and operations and maintenance costs, a sensitivity on an offshore cost factor is performed. Although, experience can be taken from offshore platforms and island conditions, much is unknown about the actual offshore cost factor for an energy island in the middle of the North Sea. Sensitivities on offshore cost factors (1.5 and 2.5) are applied to provide insight in its effect on the economic potential of P2X (see Figure 23, Figure 24, Figure 25. The allowable cost factor provides insight in the additional costs for offshore production at which it still breaks-even with onshore production. The exact allocation of these cost is not analysed, though.

The analysis show that allowable costs factor to still break-even with onshore large scale P2X cases is minor, and probably even below 10%. In the hydrogen cases the cost-factor will even lie below 100%, as in the base value the NPV of onshore production lies already above the NPV for offshore production. Remarkable is, however, that the large scale hydrogen scenario still provides a positive NPV (about €M110) when the offshore cost factor increase towards 1.5. The appliance of a 1.5 cost factor leads to negative NPV outcomes in the other large scale P2X cases, with respectively €M-1219 for ammonia and €M-1046 for methanol.

Given that that NPV-values for small scale P2X already show negative values, the application of offshore cost factors provides even worse outcomes. Although, system values such as grid balancing are not yet accounted for, to come to a positive outcome offshore production should become much cheaper (about €M120), to compete with onshore small scale production. Unless system values are considered, it will be unlikely that small scale offshore production can compete with either onshore small scale production or offshore large scale production. The more so, since it can be expected that the offshore cost factor will be higher for platform configurations than for island configuration. The rationale for this is that island configurations might be easier accessible during installation, operation and maintenance processes.

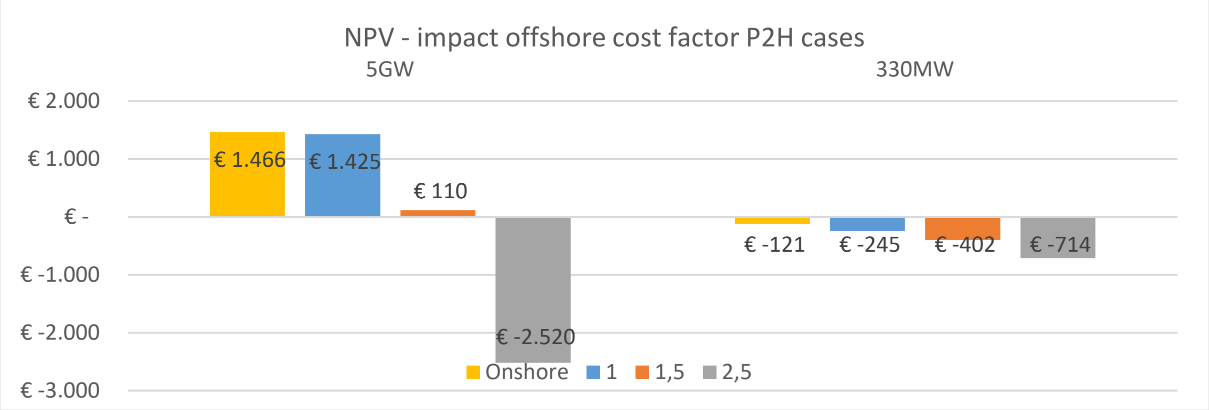

Figure 23: Impact of the offshore cost factor on the NPV of hydrogen cases system (in million euros). The onshore alternative belonging to the respective scenario is included for comparison.

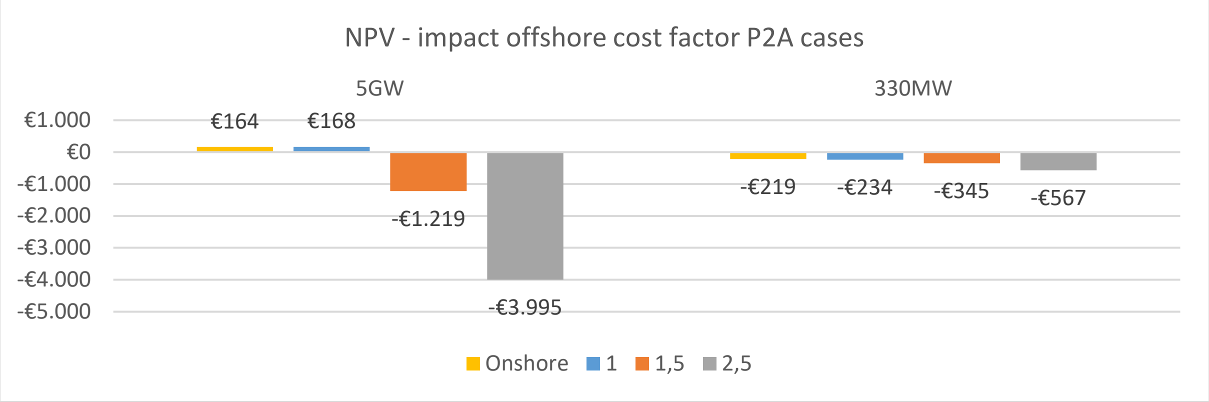

Figure 24: Impact of the offshore cost factor on the NPV of ammonia cases system (in million euros). The onshore alternative belonging to the respective scenario is included for comparison.

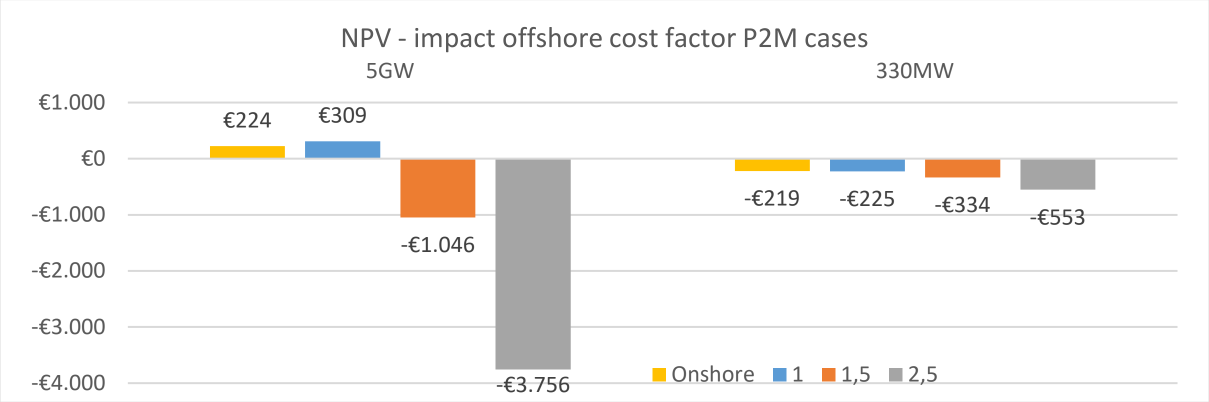

Figure 25: Impact of the offshore cost factor on the NPV of methanol cases (in million euros). The onshore alternative belonging to the respective scenario is included as the basis of comparison.

Electricity price

The electricity price affects the complete system. A rise of the electricity price results in an increase in revenues from electricity sales, but on the contrary also results in higher operational costs of the electrolyser, and as a result higher resource costs for the P2X processes. The two opposing effects are applicable at the same time, though, from the analysis we can conclude that the positive effect dominate. Hence, an increase in the electricity price to €85/MWh improves the NPV's of the offshore large scale production sides by M€2100 for hydrogen, by M€1650 for ammonia, and by M€750 for methanol (see Figure 26, Figure 27, and Figure 28). On the operational side, the back-up power needed to ensure stability and continuity of the P2X processes results in higher resource costs which supresses the positive effect for ammonia and methanol cases. It should be emphasized once more that the comparison between the ammonia and the methanol case concerning the impact of the electricity price is hard to make, due to the different technical limitations in flexibility of the two respective production processes (minimum 40% and 80% of the full load respectively), which determine the extra electricity consumption to sustain a constant production. For this reason, the ammonia process is more sensitive to the electricity price than the methanol process, because in the latter the revenue from electricity sales is dampened by the higher consumption of electricity. This can be expressed in numbers by evaluating the increase in NPV in millions of euros per euro increase of the electricity price, with are depicted in Table 17.

Table 17: Decrease in NPV per change in electricity price for the 5GW offshore scenarios

Scenario		
Hydrogen	58	MEUR in NPV/(€/MWh)
Ammonia	47	MEUR in NPV/(€/MWh)
Methanol	22	MEUR in NPV/(€/MWh)

Onshore production is slightly more affected than offshore production (especially in the large scale). The rationale for this lies in the need for back-up capacity. In the offshore case this electricity will be transmitted via the bi-directional cable and hence additional losses apply, resulting in higher costs for the offshore P2X processes. With an electricity price in the order of €30/MWh the NPV of the large scale hydrogen production remains positive. The large scale production scenarios are affected more in absolute terms, which can be explained by the higher production volumes and especially the market revenues from electricity sales.

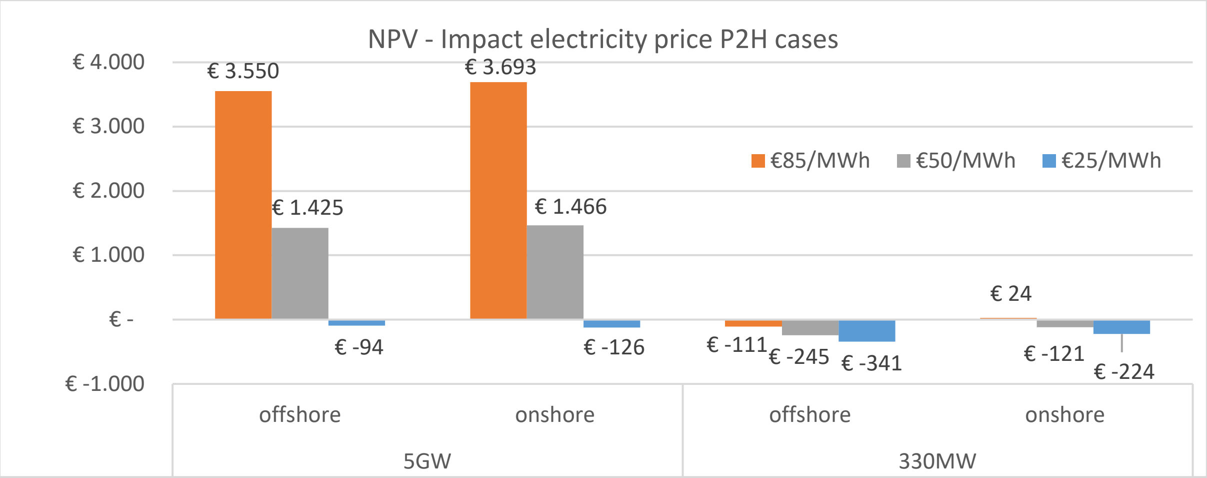

Figure 26: Impact of the electricity price on the NPV of hydrogen cases (in million euros). The electricity price is set to €50/MWh in the base case.

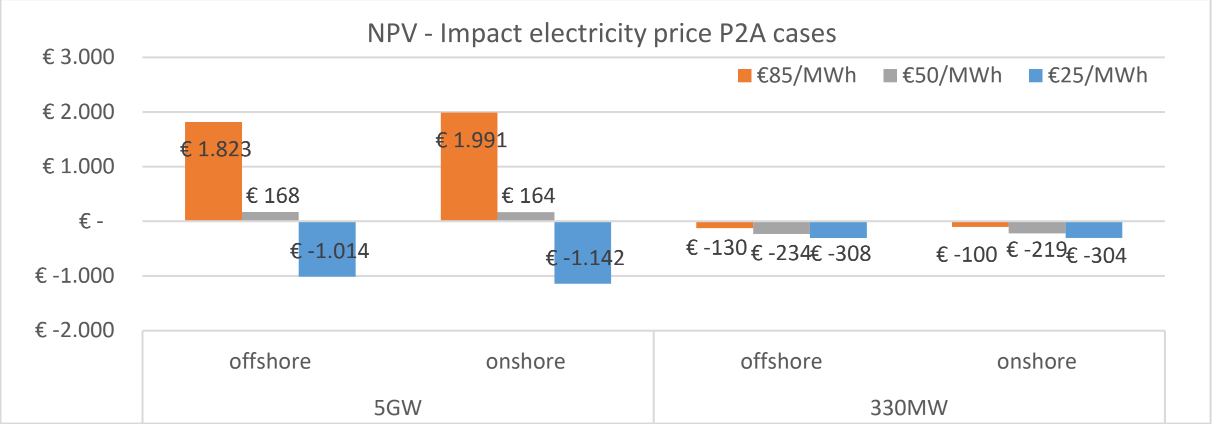

Figure 27: Impact of the electricity price on the NPV of ammonia cases (in million euros). The electricity price is set to €50/MWh in the base case.

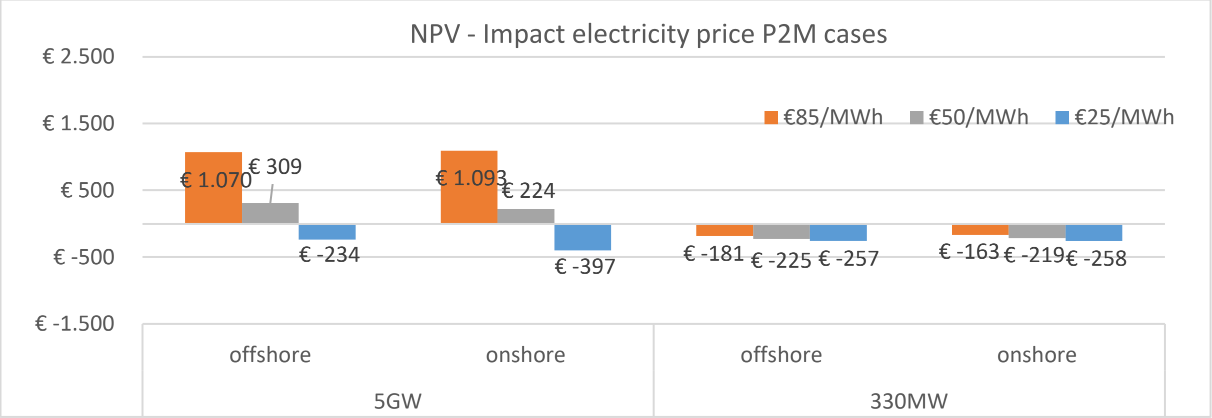

Figure 28: Impact of the electricity price on the NPV of methanol cases (in million euros). The electricity price is set to €50/MWh in the base case.

Hydrogen price

The hydrogen produced within the electrolysis process is very pure, and hence it might be suitable to serve as an energy carrier or as a potential fuel for the mobility sector. Sectors that require high quality standards for hydrogen are willing to pay a higher price. For instance, prices of 6€/kg of hydrogen are relatively normal for the mobility sector. The willingness-to-pay a higher price for hydrogen has great impact on the business case. Figure 29 highlights the effect of a higher hydrogen price on the total NPV of the hydrogen cases. In all scenarios, an increase of the hydrogen price to 6€/kg results in a more positive business case. However, if carbon-free hydrogen production has to compete with high-carbon hydrogen in the market, prices may drop to 1€/kg, and as a result the NPV turns negative. The effect is even more profound if the scale of production increases. In the small case, a hydrogen price of around €3/kg (onshore) and €4 (offshore) is required to make a positive business case.

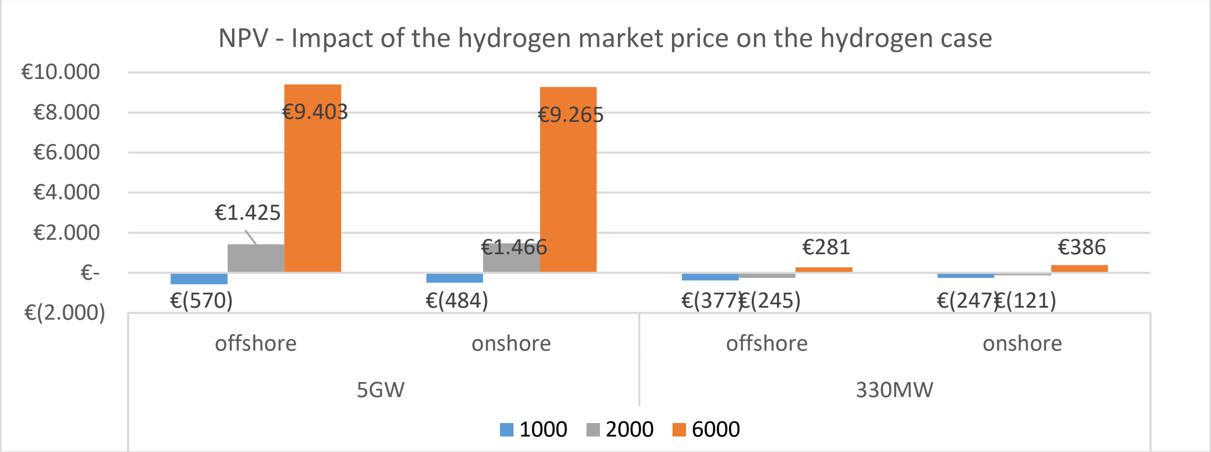

Figure 29: Effect of hydrogen price on the NPV of the hydrogen cases (in million euros). In the base case the hydrogen price is set at €2/kg.

Ammonia price

The market price of ammonia affects the profitability of the complete scenario. The value of (high-carbon) ammonia in the market is around 200-250€/ton at producer side, taking transport to harbour into account a price of 300-350€/ton would be more representable. Carbon-free ammonia, in contrast to the current way of production, doesn't emit any carbon source for its production. Hence, in order to compete with (high-carbon) ammonia the CO_2 price should rise to 150-200€/ton [15]. The expectation is that a separate market will develop for carbon-free ammonia which focuses on the application of ammonia as an energy carrier, rather than feedstock for the chemical industry (or if applied, as zero-carbon feedstock). Figure 30 highlights the effect of various ammonia prices on the total NPV of the scenarios. The effect of an ammonia price increase is much stronger for the large case scenario, due to the higher volumes of ammonia sold to the market. The outcomes show that break-even for the whole system is realised with ammonia prices slightly below current market prices (300€/tonne).

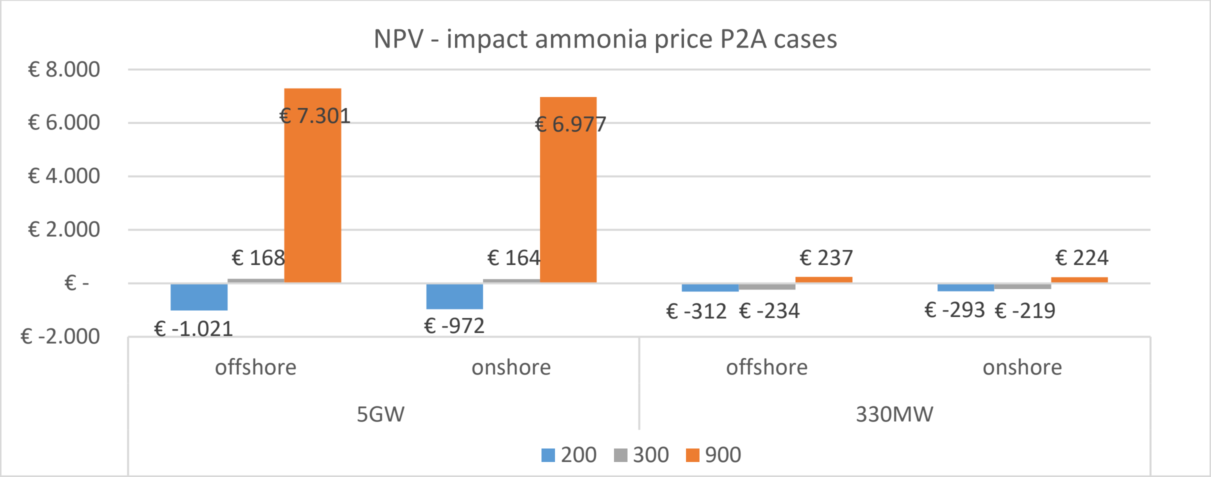

Figure 30: Impact of the ammonia price on the NPV of the complete system. In the base case the ammonia price is set at €300/ton.

Methanol price

The market price of methanol affects the profitability of the energy system similarly as the ammonia scenario. The value of (high-carbon) methanol in the market is around 300-350€/ton

[40]. Carbon-free methanol, in contrast the current mean of production, has a carbon footprint depending on the source of the CO_2. Market values for carbon-free methanol are about 550€/ton [45]. Figure 31 highlights the effect of various methanol prices on the total NPV of the scenarios. The price-effect is greatest for offshore methanol production. The outcomes show that a break-even is realised for small-scale methanol production with a methanol price of about 280 €/ton. The effect of a methanol price increase is less profound in the small-scale scenarios, due to the lower volumes of methanol sold to the market.

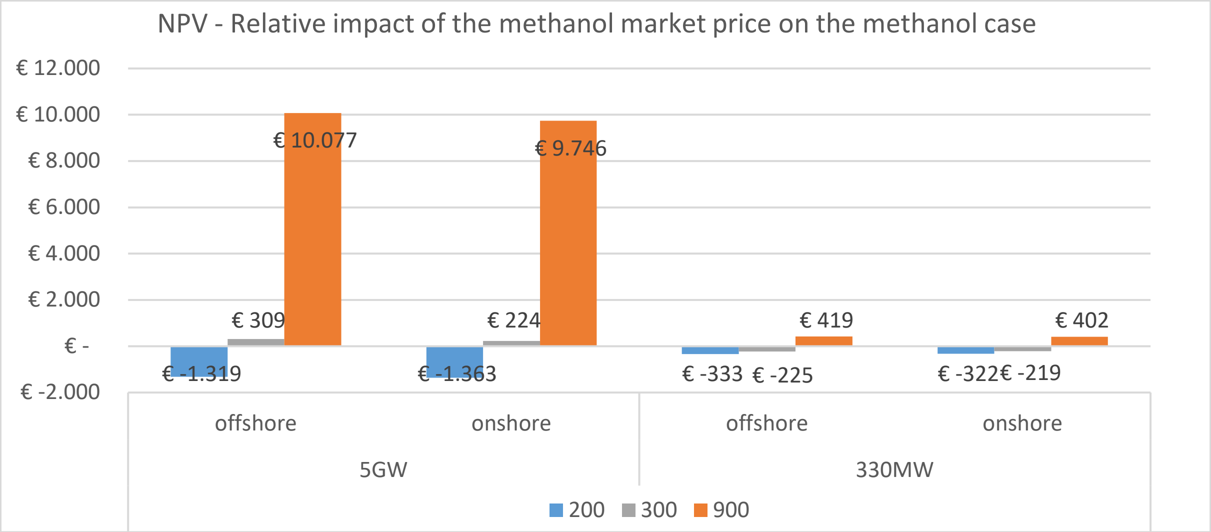

Figure 31: Impact of methanol price on the NPV of the complete system. In the base case the methanol price is set at €300/ton.

Additional, future oriented scenario analysis

Because it can be expected – given usual lead times related to the construction of artificial island, offshore pipelines etc. - that such offshore production may only take place in about a decade at the earliest, a scenario has been simulated in which: electricity prices would drop to €25/MWh (somewhat below current levels); Electrolyser CAPEX on the system level costs would be half compared to current levels (towards approx. 500k€/MW); that the relative offshore costs factor would be 1.5 overall; and that the market value of the carbon-free methanol would be about double the current market value of high-carbon methanol (towards €700/tonne). The result of this more positive scenario was that a positive NPV of some 6,700M€ (base case was 309M€) could be derived from the offshore methanol production plant (Figure 32).Note that onshore methanol production generated a comparable result and that the scenario assumed that bio-based CO_2 would be available and that the offshore plant has access to power supply from shore.

The above positive result with regard to future offshore methanol production decrease in a scenario in which the carbon-free methanol prices would reach levels not higher than some €350/tonne (219 M€); electricity prices would rise to levels of about €50/MWh (7,300M€); or the relative offshore cost factor would turn out to be 1 rather than 1.5 (7,500 M€). For offshore ammonia production the relative impacts were comparable to those of the methanol case. The optimistic scenario shows on the whole less favourable conversion results for platform cases due to diseconomies of scale.

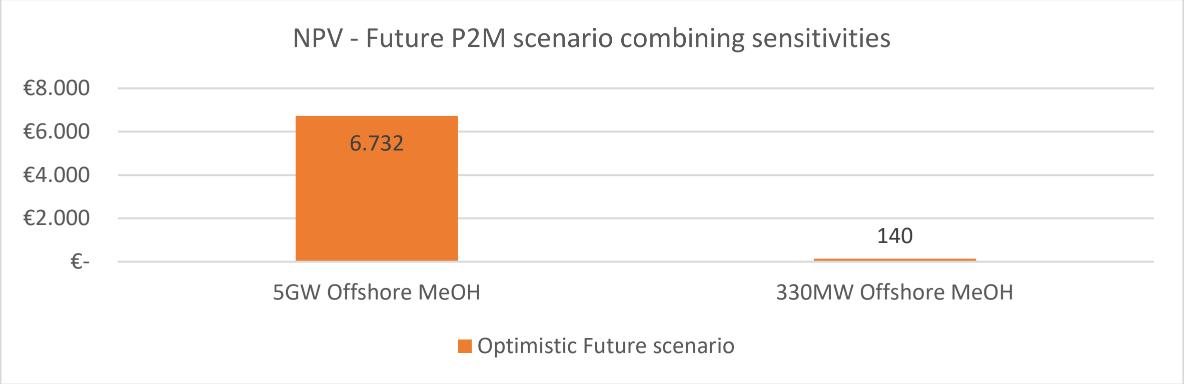

Figure 32 – NPV future optimistic scenario (Electricity price: 25€/MWh, Offshore factor: 1.5, Electrolyser CAPEX: 558 €/kW, Methanol price = 700€/ton).

Conclusion and recommendation

This report analysed in an exploratory way the conventional supply routes of wind and natural gas as well as more innovative concepts of energy transport e.g. how offshore renewable energy, notably electricity from wind energy generated on the North Sea, can be converted into energy molecules in various power-to-gas (P2G) and power-to-liquids (P2L) options (collectively: P2X options).

A levelised costs of energy (LCOE) analysis was performed for the conventional supply costs of wind energy and natural gas. The outcome showed, depending on the type of compression chosen, a LCOE of gas transmission in the range of 0.05 – 0.09 ct/kWh (LHV). Although costs do not make up the single argument for cable type selection, TNO developed a costs optimisation model to determine (in a broad perspective) the transmission cost for various typologies of an electric system. The outcomes of the LCOE of a transmission system over 150km are in line with the 2.5 cent/kWh figure mentioned in literature. The base conventional transport cost factors (e.g. pipeline CAPEX) are therefore also considered to be realistic in the subsequent calculations considering the cost of hydrogen and electricity transport in the P2X scenarios. This also supports putting the techno-economics of the P2X scenarios in perspective of conventional energy transport.

Though both conventional transport routes face currently some challenges. The transport of natural gas from offshore fields starts to decline due to the low gas price affecting the volumes of gas exploration. Although the offshore wind sector is in its infancy in the Netherlands, serious investments will be required to prevent congestion issues and to connect the wind farms located further offshore from 2030 onwards. Innovative concepts of energy transport, such as P2X, can be a promising alternative to the conventional supply routes given the high volumetric energy density properties, potential for system optimisation and the re-use existing infrastructure.

A primary step in the P2X process is the production of carbon-free hydrogen, however, the storage of pure hydrogen is on the whole rather costly as it requires either high pressures (up to 1000 bar), or very low temperatures due to its low boiling point (-253°C). Hence, processing hydrogen into other chemical compositions may be beneficial. A broad qualitative screening, for instance on market potential and offshore applicability, was conducted to select the P2X technologies and based on the criteria set methanol and ammonia seem to be the most attractive chemical routes. These P2L systems come, however, with their own spatial, logistic and technical requirements which expand the regular P2X case, where only hydrogen is considered as an energy carrier. In total, 12 P2X scenarios were analysed to gain insight in the effect of location and scale on the economic profitability, all these scenarios entail a wind-electrolyser capacity ratio of 30% conversion. This conversion ratio reduced the back-up requirements, which was provided by a bidirectional electricity connection, for ammonia and methanol such that the P2L process remained fairly continuous.

The NPV analysis show that future (sandy) energy islands were the most ideal offshore locations for large-scale or even bulk production of carbon-free hydrogen, carbon-free methanol and carbon-free ammonia, because of the economics of scale that can be realised nearby the availability of carbon-free electricity and the ability to host a multitude of functionalities, including shipping activity that also enables to transport methanol and ammonia to the most optimal markets. Hence, although an extra offshore cost of conversion applies, that did not seem to outweigh the savings on pipeline costs initially, and the extra electricity costs for the P2L system due to the constant production constraint. Moreover, it seems likely that any legal, safety or public acceptance restrictions related to onshore energy conversion and storage, may be much less of a problem if such activity takes place offshore.

Small-scale conversion is assumed to take place on (existing) platforms that are equipped with P2X - as well as with a 100 MW electrolyser-capacity. Based on these assumptions 330MW of wind capacity is required to deliver the input required for the small-scale P2X process; remaining energy may be transported via an electricity cable. The small-case offshore conversion does not provide a positive system value and is in comparison to small scale onshore production less favourable. This also emphasizes that scaling plays an important role, for example the large scenario DC cabling (CAPEX) is compared to the small scenario (AC cabling) only about 7 times more expensive in a 15 times larger power capacity scenario.

The variability of the electricity price is an important factor in the P2L systems since it causes higher costs of back-up power when the generated wind energy is low, and increases revenue when the wind is high. This causes the flexibility of the production system to be of significant importance, which differs between the ammonia and methanol processes. The less flexible methanol production process damped the extra revenue from the electricity sales. Therefore the methanol scenario seems to be less sensitive to a higher electricity price than the ammonia case if you assume a bidirectional electricity connection to be able to have a stable P2L production system.

It turned out that if the question had to be answered if methanol (or ammonia) production from offshore wind energy would at all be feasible compared to a simple scenario in which the electricity from offshore wind would be transported to its final destination to be taken up as electricity, the answer is negative for the cases in which the liquids have to compete with the existing market. Though these P2X options might become favourable if the willingness to pay for low-carbon molecules both as energy carriers and as feedstock will rise, if CAPEX of electrolyser system reduce significantly, and if system values such as flexibility or grid expansion would be valorised by the market.

In the results, considering the assumptions taken in this report, the NPV of offshore and onshore P2L production don’t differ very much. Externalities, such as balancing and potential savings on grid extension, decide whether P2X will be economically feasible at an onshore or an offshore location. When one would trust or believe in a rapidly increasing (green) methanol or ammonia market, it can pay off much to realize an energy transport system including the production of these sustainable liquids and their corresponding increase in value. Future research is needed to monetize these externalities and to capture the full system value, including the onshore electric system, of P2X.

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Appendices

Appendix A. Overview of P2X options

	Hydrogen	Methanol	Higher alcohols and ethers
Storage potential	Storage of hydrogen requires either high pressures (up to 1000 bar) or very low temperatures (-253°C). Both options require additional energy input and related losses. The energy content of Hydrogen is rather low, roughly ¼ of natural gas (per Nm³).	Liquid fuel under ambient conditions. Very similar in storage, transport and handling with currently used liquid fuels.	Alcohols are very similar in storage, transport and handling as liquid fuels. Alcohols with two or more carbon atoms have a higher energy content than methanol but are more difficult to synthesize. Ethers are liquid at room temperature starting from DEE and have a higher energy content than alcohols with the same amount of carbon atoms. The boiling points is low.
Energy efficiency	Regarding the system boundaries of the comparison .	Relatively high process efficiency (about 70%), but a part of H_2 is lost as H_2O. Large scales are necessary for efficient production.	Depending on the ether and alcohol, parts of the available hydrogen is lost as water during the conversion process.
TRL & scalability	Technology dependent. Alkaline electrolysis do exist on an industrial scale. PEM and SOEC are not applied yet for large scale production.	Much experience with methanol in the oil gas and chemical industry where the technology for megaton scale production is already operational.	R&D for catalyst and process optimization still required.
HSE	Non-toxic, but hydrogen is explosive with a low ignition energy when mixed with air in the range of 5 – 88%.	Results of animal tests show a toxicity of alcohol fuels comparable (or better) than the toxicity of common fuels. The major issue, alcohols - and especially methanol - have to face is toxicity both in terms of ingestion, skin or eye contact or inhalation. Vapours of methanol may explode when ignited.	Substantial improvement in exhaust gas quality with greatly reduced CO, NOx, and particulate matter emissions from internal combustion engines. Alcohol with 2 carbon atoms (the common alcohol) is used for human consumption - others are poisonous
Offshore applicability	Pilot projects are currently developed on offshore hydrogen production. Hydrogen easily diffuses in many metals and could result in embrittlement of the infrastructure material, making a reuse of existing pipeline infrastructure more complex.	Potential fuel for ships that transport the methanol to shore. Expected to be compatible with existing pipeline infrastructure. Established offshore carbon supply is required.	Established offshore carbon supply is required.
Market potential	Large substitution potential of grey and blue hydrogen in the industrial sector (refineries, chemical industry). Strong competition with cheaper fossil H2 production.	Good starting molecule for the chemical industry where it can easily be converted to DME (Di-Methyl-Ether, see below) or other products. Methanol can be blended with gasoline or used pure in Otto engines showing a large potential in the mobility market.	Possible fuel additive, improve the exhaust gas quality. Currently just produced for chemical industry

	DME	Fisher Tropsch Synfuels	Synthetic methane
Storage potential	Higher energy content than methanol. Gaseous at room temperature and pressure. Relatively low energy density.	Easy to store, high energy density.	High storage potential due to existing infrastructure. Relatively low volumetric energy density compared to liquid fuels.
Energy efficiency	Process efficiency of about 75%	Conversion process has typically high energy losses (around 40-50% of the original energy content)	Overall process efficiency of about 70-75% but about 50 % of introduced hydrogen is lost as H2O.
TRL & scalability	Can easily be synthesized from methanol. Technology for megaton scale production exists but is not applied yet.	Process is well known and applied at many locations worldwide (e.g. Sasol, Shell Gas-to-Liquids). Technology for megaton scale production exists	Technology for megaton scale production exists but is not applied due to large amounts of available methane worldwide (Natural Gas, Methane clathrate).
HSE	noncarcinogenic and nontoxic. Clean combustion and a global warming potential 50 times lower than methane		Cleaner combustion compared to other fossil fuels.
Offshore applicability	Established offshore carbon supply is required. Can be handled in a similar way as LPG	Compatible with existing infrastructure. Requires an established offshore supply chain of starting molecules such as Methane, Coal, Carbon monoxide and Carbon dioxide. Requires significant amounts of noble metals as catalysts.	Established offshore carbon supply is required. Distribution infrastructure already exists.
Market potential	Possible LPG substitute. Current global DME production is estimated at around 11 Mt per year, with the majority being produced in China from coal	Fuels very similar to hydrocarbon fuels now used worldwide, mostly diesel fuel. Current global production hovers around 600,000 barrels per day	Can be used directly as replacement for natural gas.

	Ammonia	Biogas upgrading	Formic Acid
Storage potential	With a boiling point of -33°C under ambient pressure / ambient temperature under 10 bar pressure, ammonia can be relatively easy stored. Difficulties in handling and storing of ammonia is also related to materials that are corrosion resistant. Relatively difficult hydrogen extraction from the carrier molecule.	Similar properties compared to natural gas which makes it possible to be stored in the existing pipeline infrastructure.	Higher volumetric energy density than hydrogen. Attractive H2 storage material due to low dehydrogenation reaction enthalpy.
Energy efficiency	Overall process efficiency of about 65%. Assuming a balanced reaction, all hydrogen can be converted to ammonia without losses.	Large variety of feedstock available where different compositions can have a negative effect on the process efficiency. Parts of hydrogen can be lost as water.	Low thermal efficiency.
TRL & scalability	Technology for megaton scale production exists and is applied e.g. in the fertilizer industry.	Processes still need to be developed for large scale.	Mature technology with large-scale industrial units is being employed but processes are mostly based on SMR.
HSE	Poisonous and corrosive		Listed on the US FDA's list of food additives indicating low risks for human health.
Offshore applicability	Available cooling water for highly exothermic reactions. There is no additional carbon supply route required. There is an existing infrastructure of trucks and trains transporting ammonia. Existing pipeline infrastructure might not be reused for the purpose of ammonia transport.	Requires an established and large offshore supply chain of biomass.	Established offshore carbon supply is required. Transportation, handling, and storage of formic acid are feasible under typical infrastructure conditions. However, it might accelerate corrosion for existing infrastructure
Market potential	Can also be used for fertilizer production (nitrates). Its global production in 2012 accumulated to 198 Mt which is the largest quantity of all synthetic chemicals.	Ship transport is available (e.g. for wood chips). Existing infrastructure could be used for the generated green gas. Can result in fully ‘green’ fuel and is very well suited for the replacement of current HC fuels. Phosphorus, Sulphur, Nitrogen removed from biomass, can be used for fertilizer production. The availability of sustainable biomass is limited.	Relatively small market shares, with an order of magnitude of factor 100 less than methanol or hydrogen (Mton production p.a.)

Appendix B. Power Curve

The wind profile was examined for three sites (“Borssele”, “FINO 1” and “Meteomast Ijmuiden”) over a 15 year period (2004-2018). This data was taken from the Royal Netherlands Meteorological Institute (KNMI) for locations with actual mast data for greater accuracy.

Data was taken for a mast height of 150m (the approximate rotor centre of the Haliade-X 12MW) at hourly resolution, and converted to power by applying an assumed power curve for the Haliade-X. Due to the confidential nature of the true power curve for the turbine, the power curve was obtained by using the published cut-in and cut-out windspeeds, by upscaling the parabolic fit for the Siemens Gamesa 7MW, and by calculating a range of values for the rated windspeed and confirming the value with GE [42] [47].

The actual curve fit equation is:

$$Power = \frac{12000}{10.25^{3.33}} * W^{3.33} - 45 \sin \varphi$$

$$\varphi = 0.743172 * W - 1.33434$$

Where, W is the wind speed in m/s. The equation is valid for wind speed $2.5 \leq W \leq 10.25$ and provides the power in kW (Figure 33 left side). When the power is below the cut-in speeds (below 2.5) or above the cut-out speed above 28 m/s the power produced is dropped to zero. For $10.25 \leq W \leq 28$ the power is 12 kW.

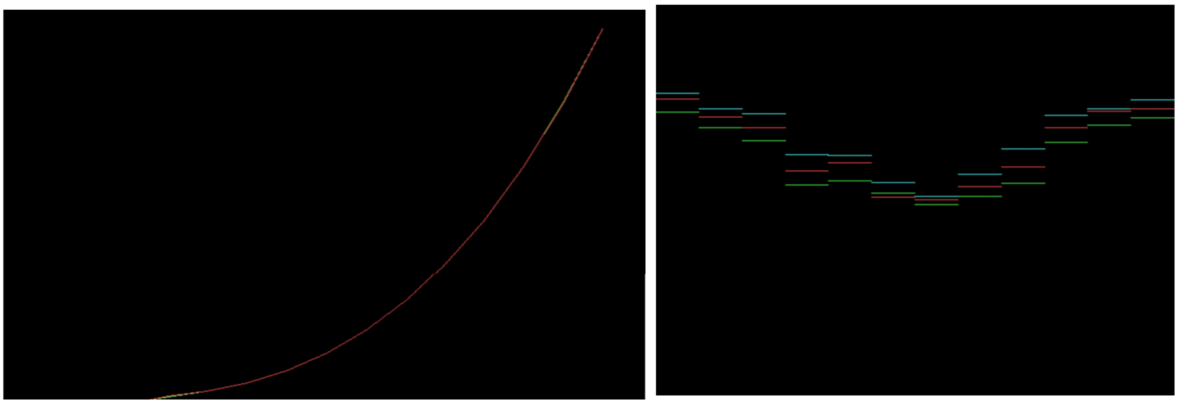

Figure 33: left side: the result of the curve fit (red) and the tabular data (green) in the range of 0 - 11m/s. Vertical scale depicts the power output (0 - 12,600 kW). Right side: fractions of the 15 year averages of the three locations. Green = Borssele, Blue = FINO1, Red = IJmuiden. Horizontal scale: 12 “months”, vertical scale 0 – 100 % of maximum power.

Figure 33 (right side) presents the averages over the maximum power from the years 2004 to 2018. A “month” is 1/12 of the length of the total year, to circumvent the differences in lengths of the calendar months and thus enable the direct comparison between the numbers.

The above methodology yielded a capacity factor of 60.5%, 63.36% and 65.98% for the Borssele, IJmuiden and FINO1 sites, respectively, with the average over the three sites being 63.2%. This is deemed to be in close agreement to the expected result. The values for a single turbine were scaled linearly to the size of a wind farm. Note that wake losses have not been taken into account. The differences are relatively small between the three different locations. They all show the typical behaviour of maximum production during the winter months, gradually decreasing towards the summer and climbing again during the fall. Important to note is that year-on-year deviations can be in the order of 20%.

Appendix C. Production Mode

Constant Proportion

In this mode a constant percentage (e.g. 70%) of the instantaneous wind energy produced would be converted to hydrogen (Figure 34). The average capacity factor of the electrolyser end ups to be around 42% (70% scenario) and 18% (30% scenario). This is the simplest case but entails significant downsides, with constantly varying hydrogen production rate, constantly varying production price, constantly varying electricity supply, lower efficiency (largely due to compression), and equipment constraints that lead to oversizing of some parts of the balance of plant, and the need for very large amounts of storage or backup power for any P2Liquids scenario.

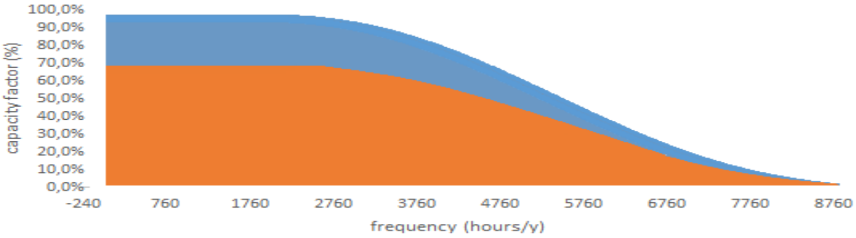

Figure 34: Frequency domain outline of constant production mode (blue: wind profile, orange: hydrogen profile)

Wind Following

In this mode the electrolysers would operate when the wind power production is above a threshold level, with the threshold determined to give an anticipated percentage yield throughout the year as hydrogen, or when the power produced is above the transmission capacity of the electrical transmission system. This mode would give the advantage of more constant supply of electricity. The disadvantage of this mode would be highly varying hydrogen production, somewhat varying production price, lower-than-max efficiency, and equipment constraints. Storage or backup power requirements utilising this mode would be even greater than those in the constant proportion mode. The average capacity factor of the electrolyser ends up to be around 35% (70% scenario) and 11% (30% scenario) (see Figure 35).

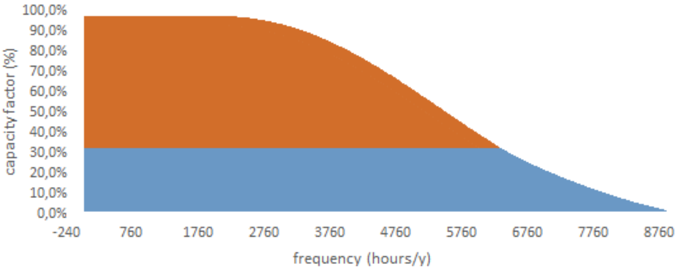

Figure 35: Frequency domain outline of wind following (blue: wind profile, orange: hydrogen profile)

Price Following

In this mode the electrolysers would operate whenever wind energy is below a certain threshold market price. The threshold price would set for whatever fuel cost would make the hydrogen sale cost effective. The advantage of this would be lower energy costs for the electrolyser, and the supply of less varying electrical power level to shore (as the low price of wind energy would often coincide with high wind production, with these two expected to converge with time with the increased penetration of offshore wind capacity). The disadvantages, as above, would be highly varying hydrogen production, lower-than-max efficiency, and equipment constraints.

Appendix D. Back-up power solutions

Hydrogen storage as back-up

Neglecting the direct electrical power requirements for the two synthesis processes, it is possible to utilise hydrogen storage to ensure that the process has a continuous feed of hydrogen to meet its lower bound on flexibility. Figure 36 shows the investment costs (based on a hydrogen storage cost of €500/kg- *an assumption based on hydrogen density of 14 kg/m³ at 200 bar and 25°C, and cylindrical storage shape* [23]) for hydrogen storage and the system response in terms of percentage downtime per year[35]. It can be seen that there are diminishing returns for more storage capacity, and that storage to cover all downtime quickly loses feasibility when the flexibility of the system is lower, as in the methanol synthesis case.

The corollary of this is that relatively small investments in hydrogen storage have large returns regarding system downtime – in the ammonia case, the first €55M invested improves system downtime by 14%, with the remaining €367M investment bringing downtime from 4.8% to 0%.

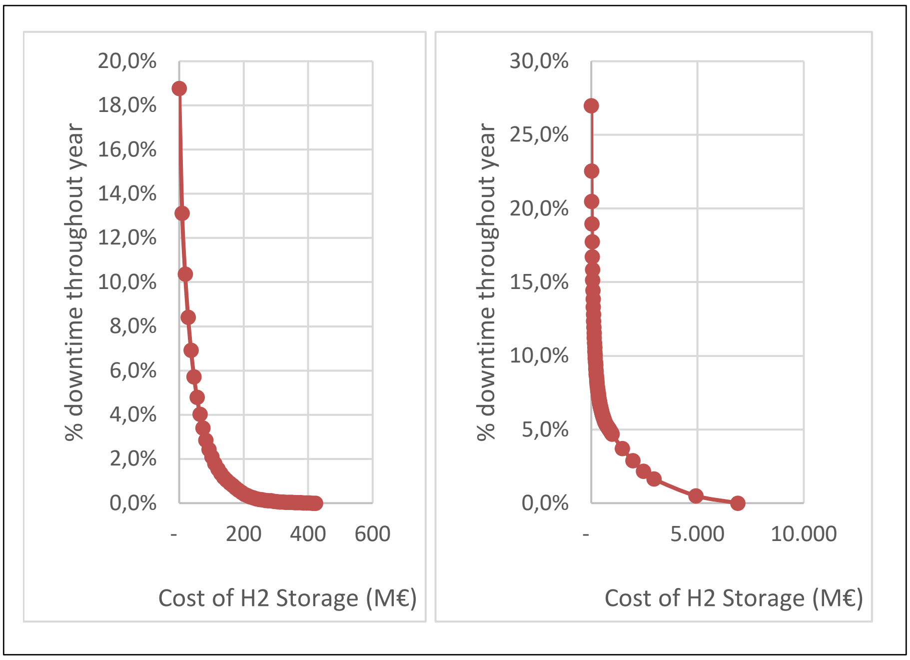

Figure 36: Hydrogen storage as back-up for P2Liquids. Left side illustrates the back-up requirements from hydrogen storage for production of ammonia. Right side illustrates the back-up requirements from hydrogen storage for production of methanol.

Battery storage

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[35] We have taken a modular approach (400kg/unit) regarding the appliance of hydrogen storage. Economies of scale might however apply reducing storage costs

Battery storage can be utilised to ensure a continuous production profile of the electrolyser which in turn continuously supplies the P2X production. The costs of batteries as a back-up solutions takes into account the battery State Of Charge (SOC), and compares it to the surplus/deficit. A surplus of wind energy is used to charge the battery, until its max SOC is reached. A minimum requirement deficit is matched at all times (provided sufficient SOC), and a nominal deficit is matched only if the battery is fully charged. In the case that the battery is not full, the battery SOC is increased by the surplus of the minimum P2Liquids requirements. This prioritisation of the battery charging over running the P2Liquids process at nominal allows a significant decrease in battery capacity for the same level of system robustness (number of hours in deficit of minimum requirements over the year). Based on the cost development of battery storage (Li-ion) [48] and the assumption that the lower end of the cost estimate is valid due to economics of scale, battery costs end-up being around 250 €/kWh. Figure 37 displays the system availability due to increasing battery capacity.

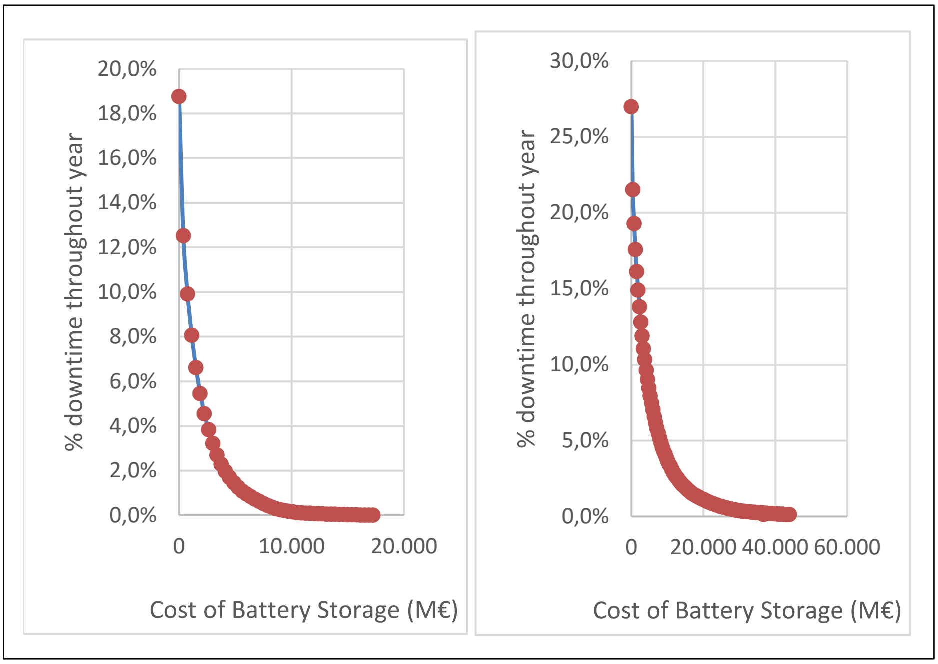


Figure 37: Battery storage as back-up for P2Liquids. Left side illustrates the back-up requirements from hydrogen storage for production of ammonia. Right side illustrates the back-up requirements from hydrogen storage for production of methanol.

The effect of increasing battery storage capacity is similar to what has been observed previously with hydrogen storage, however the costs for each reduction in system downtime are significantly higher. The result implies that without a very significant drop in cost of battery storage, through technological evolution or economics of scale (which have been ignored here because of the assumption of modularity), batteries alone will remain an economically unfeasible solution to the flexibility problem.

Appendix E. Desalination system

The required demi-water needs to be non-conductive with a quality of <1 micro Siemens and further its required that the control unit of the water treatment system is connected to the electrolysis plant's SIMATIC PCS7. Demi water is quite aggressive for metals, even for stainless steel. So in many cases plastic materials are used to transport the demi water.

In order to retrieve demi-water from saltwater we need a complete process of desalination including:

- Pre-treatment, to remove dissolved solid content (feed pump + multimedia filtration)
- Sea water Reverse Osmosis, to remove salts towards 300 ppm (cartridge filtration + high pressure pump + reverse osmosis modules)
- Low brackish water Reverse Osmosis, to bring it down to a level <50ppm.
- Post-treatment, ion exchange resin and to ensure water quality reaches < 1 uS/cm (or 0, 641ppm) (realisation).

A specific component that is imperative for electrolysis is the availability of demineralised water. On the bases of full load, some less than 2 million litres of this water would be required per year. This can be produced from sea water, but that requires a demineralisation unit. The salinity of North Sea water averages between 34 and 35 grams of salt per litre; desalination via reverse osmosis implies high energy usage to ensure the right operating pressure of seawater, this way, almost all (around 95 to 99%) of dissolved salts is left behind in the reject stream. This may imply that additional technologies have to be applied to make sure that pure demineralised water can be fed into the electrolyser system. Usually, desalination units are not terribly big. The electrolysis process needs demineralized or demi water as input, this means that all minerals and salts need to be removed. The required demi-water for the Silyzer 200 and probably also for the Silyzer 300 needs to be non-conductive with a quality of <1 micro Siemens and further its required that the control unit of the water treatment system is connected to the electrolysis plant's SIMATIC PCS7. Demi water is quite aggressive for metals, even for stainless steel. So in many cases plastic materials are used to transport the demi water. Figure 38 gives an impression of how such an integrated system of pre-treatment and Sea water Osmosis system might look like, though the interconnecting piping between filters and Reverse Osmosis is not included.

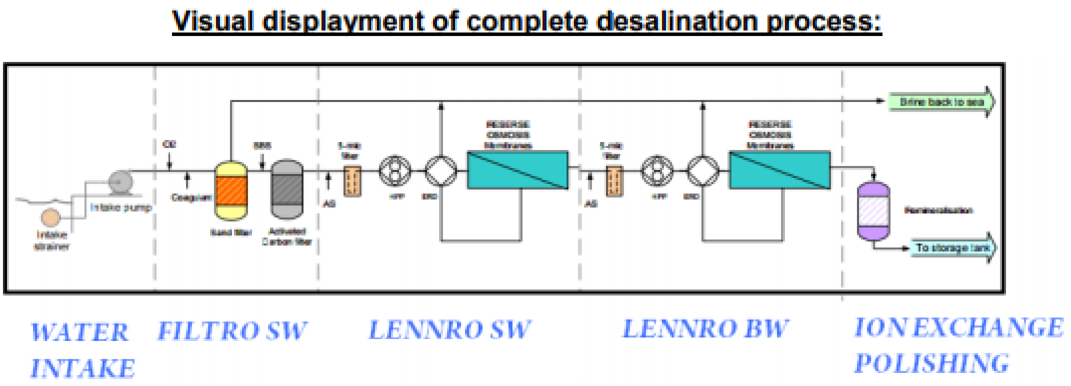


Figure 38: visual display of desalination process based on [24]

Pre-treatment

North Sea salinity levels range between 35-36 gram of salts per litre or total dissolved solids content of around 35,000 ppm. Seawater with a total dissolved solids content of around 35,000 ppm is regarded as standard seawater, but the composition of seawater is affected by the influenced from land activities and therefore a seawater analysis should be performed prior to installation to select the right treatment method. Before the salt can be extracted from the water the water should be pre-treated. The kind of pre-treatment system that is used greatly depends on the feed water quality and hence on the source, composition and function of the feed water. Therefore, a very accurate water analysis on the concentration of inorganic salts, dissolved solids and other data of the feed water should be carried out.

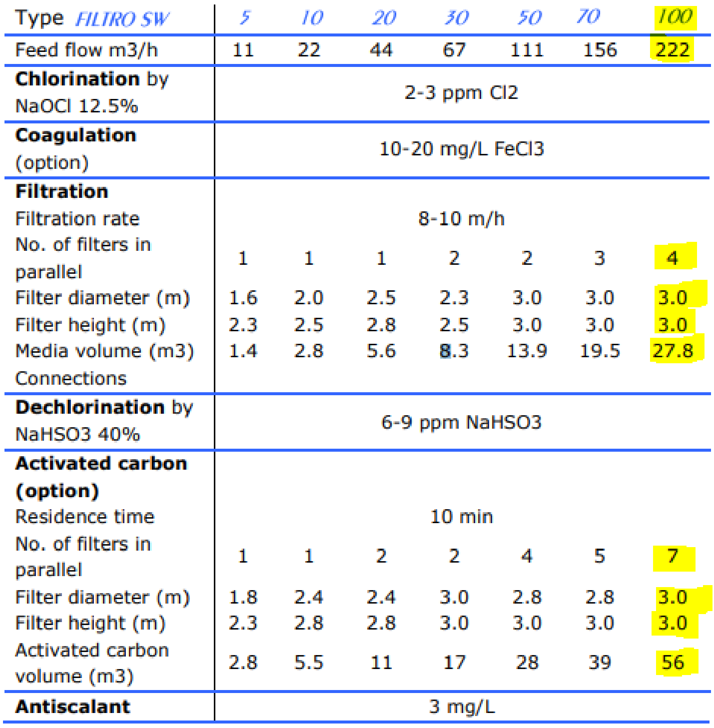
Without a pre-treatment module the Reverse Osmosis is limited by the osmotic pressured caused by a high degree of dissolved solids contents which cause affectivity and shortens the lifespan of the Reverse Osmosis installation. There are typically 3 function of pre-treatment:

- Scaling prevention and control: Pre-treatment methods help to prevent the scaling or accumulation of insoluble salts in the Reverse Osmosis Membrane, such as calcium carbonate (CaCO3) and calcium sulphate (CaSO4). The accumulation of insoluble salts is positively related to the recovery rate of the RO installation, hence an increase in the salt recovery ratio also increase the scaling of insoluble salts. Therefore, anti-scalents should be added to the feed water to prevent the precipitation of insoluble salts. However if the use of anti-scalents is limited RO membrane elements need to replaced more often (each one to two years) and have a higher quantity of energy intake.

- Prevention of fouling by colloids: Pre-treatment methods help to prevent colloidal pollution which affect the RO process by diminishing its productivity levels. The sources of feed water pollution varies from bacteria, clay, and iron corrosion products, however, chemical products that are used during pre-treatment may also cause fouling of membranes. Fouling can be detected by MFI (Modified Fouling Index) measurement and if present can be decreased by: filtration (sand, candle ultra and micro), coagulation, and flocculation.

- Biofouling prevention: The feed water contains microorganisms, which are colloidal pollutants, because they are never larger than 1 to 3 nm. Biological growth within a membrane system negatively influence the system by increasing the pressure at the supplier side of the membrane, telescoping (shoving apart of the membrane) and membrane damage.

The project considers the filtro SW of Lenntech in the techno-economic analysis. “FiltRO SW is a flexible pre-treatment package that can be adapted to the seawater uptake. The standard FiltRO SW package includes a chlorination, a multimedia filtration, a declorination step and an antiscalant injection. Operational steps are required for more “dirty” waters, such as pre-coagulation and/or active carbon”. The project focusses on large scale uptake of seawater, and therefore the largest pre-treatment system, 100m³/h, has been used within the techno-economic analysis (see Figure 39)



Type *FILTRO SW*	*5*	*10*	*20*	*30*	*50*	*70*	*100*
Feed flow m3/h	11	22	44	67	111	156	222
Chlorination by NaOCl 12.5%	2-3 ppm Cl2						
Coagulation (option)	10-20 mg/L FeCl3						
Filtration							
Filtration rate	8-10 m/h						
No. of filters in parallel	1	1	1	2	2	3	4
Filter diameter (m)	1.6	2.0	2.5	2.3	3.0	3.0	3.0
Filter height (m)	2.3	2.5	2.8	2.5	3.0	3.0	3.0
Media volume (m3)	1.4	2.8	5.6	8.3	13.9	19.5	27.8
Connections							
Dechlorination by NaHSO3 40%	6-9 ppm NaHSO3						
Activated carbon (option)							
Residence time	10 min						
No. of filters in parallel	1	1	2	2	4	5	7
Filter diameter (m)	1.8	2.4	2.4	3.0	2.8	2.8	3.0
Filter height (m)	2.3	2.8	2.8	3.0	3.0	3.0	3.0
Activated carbon volume (m3)	2.8	5.5	11	17	28	39	56
Antiscalant	3 mg/L						

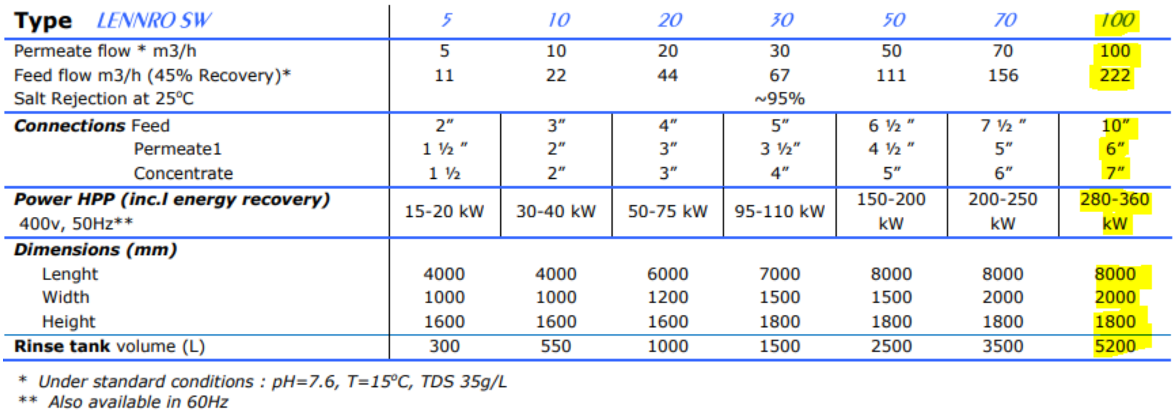
Figure 39: Filtro SW - seawater desalination unit [29]. Yellow highlights the input used in the calculations.

<u>Sea Water Reverse Osmosis</u>

Reverse Osmosis, commonly referred to as RO, is a process where you demineralize or deionize water by pushing it under pressure through a semi-permeable Reverse Osmosis Membrane.30 A semipermeable membrane is a membrane that filters salt water by allowing the passage of water molecules but not the majority of dissolved salts, organics, bacteria and pyrogens. Whereas Osmosis occurs naturally, the reverse osmosis process requires energy that 'pushes' the water through the semipermeable membrane by applying pressure that is greater than the naturally occurring osmotic pressure in order to desalinate water in the process, allowing pure water through while holding back a majority of contaminants. Thus, a pump increase the high pressure pump the salty side of the Reverse Osmosis Membrane and forces the water across the semi-permeable membrane, leaving almost all (around 95% to 99%) of dissolved salts behind in the reject stream.

The pressure required for the desalination process depends on the salt concentration in the feed water. The relationship is positive, implying that pressure increases with increments in salt concentration. The technique of Lenntech usually has around 96% to 99% of the dissolved salts removed from the feed water, leading to water quality of 300 ppm.

Although the reverse osmosis has high investment cost, it has relatively low operational costs in comparison with its first best alternative chemical desalination. For instance, energy is recovered by turbine or pressure exchanges. For this study, we assumed the implementation of the LennRO-SW system with a production capacity of 100m^3/H. Size dimension and power requirement of this systems are depicted Figure 40.



Type *LENNRO SW*	*5*	*10*	*20*	*30*	*50*	*70*	*100*
Permeate flow * m3/h	5	10	20	30	50	70	100
Feed flow m3/h (45% Recovery)*	11	22	44	67	111	156	222
Salt Rejection at 25°C				~95%			
Connections Feed	2”	3”	4”	5”	6 ½ ”	7 ½ ”	10”
Permeate1	1 ½ ”	2”	3”	3 ½”	4 ½ ”	5”	6”
Concentrate	1 ½	2”	3”	4”	5”	6”	7”
Power HPP (inc.l energy recovery) 400v, 50Hz**	15-20 kW	30-40 kW	50-75 kW	95-110 kW	150-200 kW	200-250 kW	280-360 kW
Dimensions (mm)							
Lenght	4000	4000	6000	7000	8000	8000	8000
Width	1000	1000	1200	1500	1500	2000	2000
Height	1600	1600	1600	1800	1800	1800	1800
Rinse tank volume (L)	300	550	1000	1500	2500	3500	5200

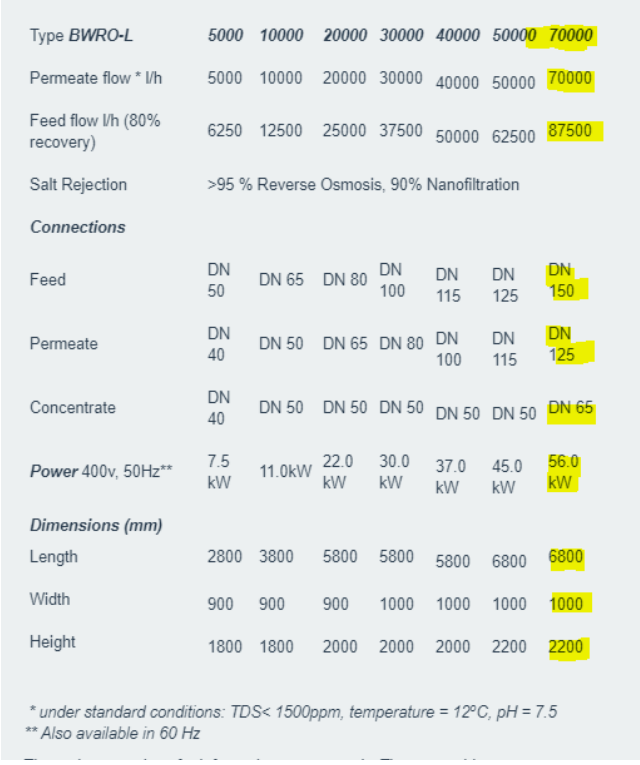
* *Under standard conditions : pH=7.6, T=15°C, TDS 35g/L*
** *Also available in 60Hz*

Figure 40: Lennro SW - seawater desalination unit [29]. Yellow highlights the input used in the calculations.

The integrated system (example from 30 m³/h system), depicted in Figure 41, is equipped with: pre-treatment installation including feed pump and multimedia filtration, Seawater Reverse Osmosis process consisting of cartridge filtration, high pressure pump and the reverse osmosis modules and lastly a post-treatment section for remineralization. The interconnection between systems is very important and if the pre-treatment process is not geared to the installation it may cause a system overload, which cause that system parts need cleaning much more often to restore productivity and salt retention.

Low Brackish water Reverse Osmosis to bring quality down to a level <50ppm

After the complete process of sea water reverse osmosis water quality reaches a level of 300 ppm. A second desalination process is therefore needed to improve water quality further. According to Lenntech, this can be done best by a second reverse osmosis plant. However, before water can be fed into the second desalination process, the LennRO-BW, certain requirements with regard to water quality should be reached.



Type *BWRO-L*	*5000*	*10000*	*20000*	*30000*	*40000*	*50000*	*70000*
Permeate flow * l/h	5000	10000	20000	30000	40000	50000	70000
Feed flow l/h (80% recovery)	6250	12500	25000	37500	50000	62500	87500
Salt Rejection	>95 % Reverse Osmosis, 90% Nanofiltration						
Connections							
Feed	DN 50	DN 65	DN 80	DN 100	DN 115	DN 125	DN 150
Permeate	DN 40	DN 50	DN 65	DN 80	DN 100	DN 115	DN 125
Concentrate	DN 40	DN 50	DN 50	DN 50	DN 50	DN 50	DN 65
Power 400v, 50Hz**	7.5 kW	11.0kW	22.0 kW	30.0 kW	37.0 kW	45.0 kW	56.0 kW
Dimensions (mm)							
Length	2800	3800	5800	5800	5800	6800	6800
Width	900	900	900	1000	1000	1000	1000
Height	1800	1800	2000	2000	2000	2200	2200

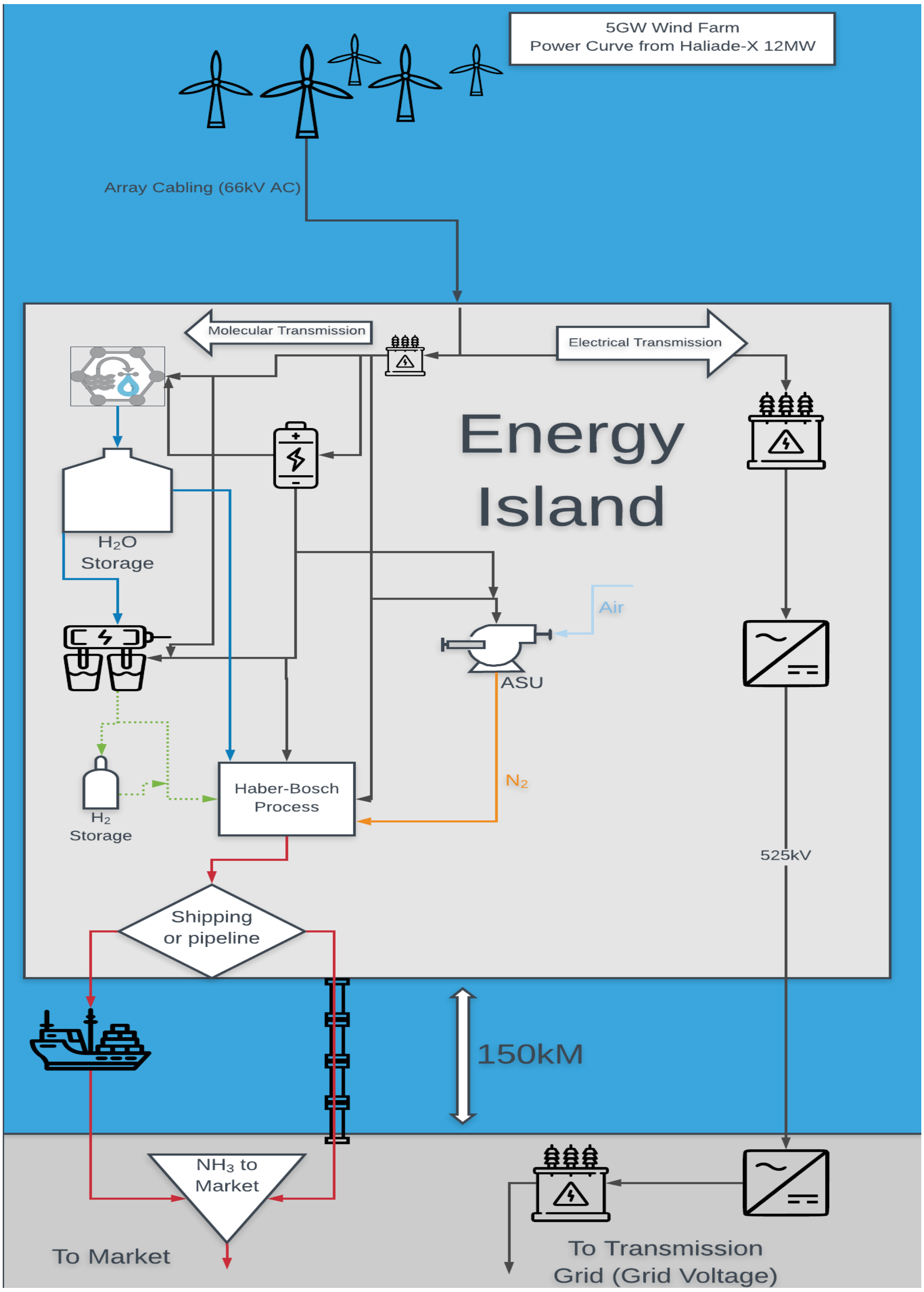
** under standard conditions: TDS< 1500ppm, temperature = 12°C, pH = 7.5*
*** Also available in 60 Hz*

Figure 41: BWRO – L – seawater desalination unit based on [45]. Yellow highlights the input used in the calculations.

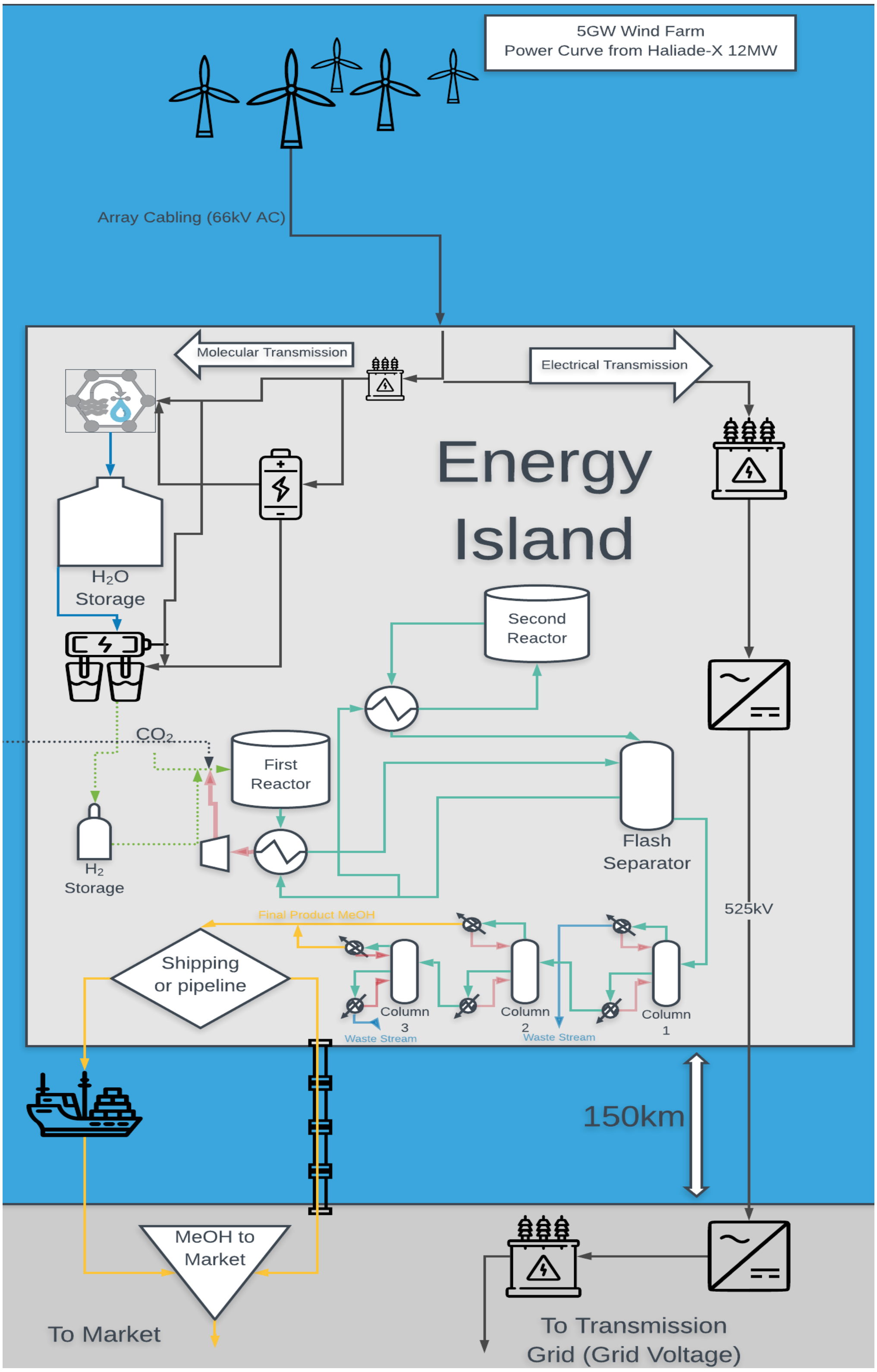
Ion exchanger polishing

To complete the desalination process the permeate flow from the LennRO-BW systems should pass by the ion exchanger polishers. Ion exchange recovery are insoluble granular substances which have in their molecular structure acidic or basic radicals that can exchange. The positive or negative ions fixed on these radicals are placed by ions of the same sign in solution in the liquid in contact with them. The costs of the ion exchanger polishers. Lenntech engineers design and build tailor-made mixed bed polishing plants after Reverse Osmosis or Ion Exchange demi plants to produce demi-water below 0,1 uS/cm.

Appendix F. Detailed process flow of P2A (5GW case)



Appendix G. Detailed process flow of P2M (5GW case)



Appendix H. Island Costs

Table 18 provides and overview of the cost elements of an island structure. The table has been zxz xcq4retrieved from D.3.6

The additional necessary area for the large scale P2L processes are used to determine the necessary extra sand fill (2%). This increases the revetment size also, but with a small percentage as the original width of the revetment is not necessarily extended, only the length). If you expand the island area, you only need to extend with $\frac{A_{extra}}{w} = length_{extra}$, where A_{extra} is the additional surface necessary (e.g. 5600m^2 in the Ammonia case), w the original width (possibly a share of the original width to secure a proper length of the P2L environment, you can't place the reactors on a stroke of e.g. 1 meter.) and $length_{extra}$, *i.e.* the final necessary extra revetment. In the most conservative case you add a square of extra surface area resulting in extra revetment length (times two for both sides) of:

$$\sqrt{5600 * 2} = 150\ meter$$

This is the most inefficient way, and it is assumed that the minimum length (as the system is mostly a train of reactors/compressors, except the storage tanks with a diameter of approx. 60 meter) is constrained to the storage facility. This comes down to maximum of 120 extra revetment, i.e. only 5% increase of the original cost. Table 18: overview of island costs

Table 18: overview of island costs

Code	Description	Budget Unit Prices (-35%/+35%)
	Building Cost Island without infrastructure	
1	Revetment	200.000 €/m
2	Breakwater	225.000 €/m
3	Sand fill (incl. royalties and compaction)	7,50 €/m³
4	Cable landing facilities	45.000.000 €/TP
5a	Harbor, quay walls incl. scour protection and bollards	125.000 €/m
5b	Harbor, slope + jetty	25.000 €/m

Appendix I. NPV datatable

	330MW Offshore H2 30%	330MW Onshore H2 30%	330MW Offshore NH3	330MW Onshore NH3	330MW Offshore MeOH	330MW Onshore MeOH	5GW Offshore H2 30%	5GW Onshore H2 30%	5GW Offshore NH3	5GW Onshore NH3	5GW Offshore MeOH	5GW Onshore MeOH
Total wind energy generated (TWh)	1827	1827	1827	1827	1827	1827	27681	27681	27681	27681	27681	27681
Total electricity supply to onshore grid (TWh)	1085	1085	1085	1085	1085	1085	16700	16700	16700	16700	16700	16700
Total P2L supply to system (onshore) (TWh)	449	433	415	390	609	586	6810	6658	6281	5999	9223	8991
Share of input (Liquids) (LHV)	0	0	0	0	0	0	0	0	0	0	0	0
Share of input (Electricity)	1	1	1	1	1	1	1	1	1	1	1	1
Investments (CAPEX)	586	489	513	512	510	512	4878	4852	5008	5036	4946	5006
Total structure costs	57	53	57	53	59	53	919	590	920	592	923	594
Capex Cables	217	254	217	254	217	254	598	833	598	833	598	833
Capex Inductors	5	3	5	3	5	3	0	0	0	0	0	0
Capex Transformers	8	9	8	9	8	9	0	0	0	0	0	0
Capex Onshore Substation	34	37	34	37	34	37	227	320	227	320	227	320
Capex Rectifiers	0	0	0	0	0	0	890	1218	890	1218	890	1218
Capex collection system	0	0	0	0	0	0	0	0	0	0	0	0
Capex electrolyser	135	113	135	113	135	113	1824	1605	1824	1605	1824	1605
Capex stack replacement	16	16	16	16	16	16	247	243	247	243	247	243
Capex H2 compressor	3	2	4	4	0	0	46	25	63	63	0	0
CAPEX H2 new pipeline	108	0	0	0	0	0	0	0	0	0	0	0
Capex H2 pipeline crossings & landing	0	0	0	0	0	0	108	0	0	0	0	0
Capex desalination unit	1	1	1	1	2	1	19	19	20	19	23	22
Total Capex MeOH feed compressor	0	0	0	0	0	0	0	0	0	0	2	2
Total Capex MeOH reactor	0	0	0	0	21	21	0	0	0	0	133	130
Total Capex distillation	0	0	0	0	3	3	0	0	0	0	18	18
Total Storage tanks	0	0	0	0	0	1	0	0	0	0	16	20
Total Capex ship	0	0	13	0	9	0	0	0	66	0	46	0
Total CAPEX ASU	0	0	5	4	0	0	0	0	28	27	0	0
Total CAPEX NH3 synthesis and Pretreatment	0	0	15	14	0	0	0	0	93	90	0	0
Total CAPEX NH3 storage	0	0	2	2	0	0	0	0	30	26	0	0
Exploitation (OPEX)	453	416	487	459	569	547	5852	5748	6556	6372	7795	7697
OPEX Total structure	18	16	18	16	18	16	29	29	29	29	29	29
OPEX Cables	39	46	39	46	39	46	107	149	107	149	107	149
OPEX Inductors	1	0	1	0	1	0	0	0	0	0	0	0
OPEX Transformers	1	2	1	2	1	2	0	0	0	0	0	0
OPEX Onshore Substation	6	7	6	7	6	7	41	57	41	57	41	57
OPEX Rectifiers	0	0	0	0	0	0	160	219	160	219	160	219
OPEX Collection system	0	0	0	0	0	0	0	0	0	0	0	0
Electricity grid energy to system	0	0	22	22	61	61	0	0	327	327	927	927
OPEX Electrolyser	24	20	24	20	24	20	327	288	327	288	327	288
OPEX Desalination unit	0	0	0	0	0	0	3	3	4	3	4	4
Electricity Electrolysis	333	321	353	332	399	384	5056	4943	5351	5111	6050	5898
Electricity Desalination unit	0	0	0	0	0	0	4	4	5	5	6	6
OPEX Compressor	2	1	3	3	0	0	33	18	45	45	0	0
Electricity Demand H2 compressor	5	2	8	7	0	0	69	36	118	112	0	0
OPEX Pipeline	22	0	0	0	0	0	22	0	0	0	0	0
Total opex MeOH feed compressor	0	0	0	0	0	0	0	0	0	0	0	0
Electricity demand MeOH feed compressor	0	0	0	0	1	1	0	0	0	0	9	8
Total Opex MeOH reactor	0	0	0	0	4	4	0	0	0	0	24	23
Electricity demand distillation	0	0	0	0	3	3	0	0	0	0	43	42
Total Opex distillation	0	0	0	0	3	3	0	0	0	0	47	45
OPEX Ship	0	0	7	0	7	0	0	0	14	0	20	0
Total OPEX ASU	0	0	1	1	0	0	0	0	5	5	0	0
Total OPEX NH3 synthesis	0	0	3	3	0	0	0	0	17	16	0	0
Total OPEX storage	0	0	0	0	0	0	0	0	5	5	0	0
Revenues / avoided costs	794	784	766	752	853	841	12155	12065	11732	11572	13050	12927
Final Hydrogen output	263	253	0	0	0	0	3989	3900	0	0	0	0
Final Ammonia oputput	0	0	235	221	0	0	0	0	3566	3407	0	0
Final methanol output	0	0	0	0	322	310	0	0	0	0	4884	4761
Final electricity output	531	531	531	531	531	531	8166	8166	8166	8166	8166	8166
Total	-245	-121	-234	-219	-225	-219	1425	1466	168	164	309	224

Appendix J. LCOE

Noteworthy is that the various cost components do not say anything about the allocation to the system costs (electric or molecular). The allocation of costs is of great importance in order to make proper judgements on the LCOE costs of both the electric and molecular system. The allocation of structure costs vary across the scenarios. Table 19 provides an overview on the allocation outcomes for the 5GW scenario. The island costs (structure costs) are allocated on the basis of the relative CAPEX distribution. Although, the structure configuration for onshore hydrogen production only consist of electric system components, a 40% share of the structure costs is expected to be carried by the molecular system. The is based on the relative CAPEX distribution of the electric and molecular system. As the electric has higher CAPEX in the onshore scenarios, a smaller proportional share of the island structure costs is carried by the molecular system. The scenarios with offshore hydrogen production on islands show a higher allocation of costs to the molecular system. This increases, as expected, when conversion rates increase from 30% to 70%. The allocation of transmission costs is based on the distribution of energy (MWh) to the molecular and electric system. In the offshore production variants no transmission costs are allocated to the molecular system. Although, the electrolyser capacity is set to either 30% or 70% of the total wind capacity installed, the distribution of energy to the electrolyser is slightly higher, which can be explained by the production profile of both the wind farm as the electrolyser. To illustrate, the load factor of an offshore wind park is 63% (about 5520 hours), whereas the load factor of the production profile for the electrolyser in the 30% case reaches 79% (6920 hours). Hence, the electricity distributed to the electrolyser system (MWh) lies above the capacity factor applied.

Table 19: Allocation of costs to the molecular system (5GW scenario)

	Offshore		Onshore	
	Ammonia	Methanol	Ammonia	Methanol
Total structure costs (M€)	965	965	620	620
Allocation cost island structure	55%	55%	44%	43%
Total costs electric system (M€)	3150	3148	4350	4350
Allocation cost electric system	0%	0%	62%	62%

Ammonia

Figure 42 shows the outcomes of the LCOE in €/ton for the ammonia cases. Onshore ammonia production seems economically less preferable on this LCOE basis. This can for a great extent be explained by the fact that costs are not included for harbour infrastructure (refuelling etc.) and no cost factor is applied. It is very unlikely that the LCOE for offshore production remains more positive when this offshore cost factor is applied. Moreover, one should be careful with the interpretation of the data, at a higher LCOE for ammonia goes hand in hand with an lower LCOE for the electrical part of the system.

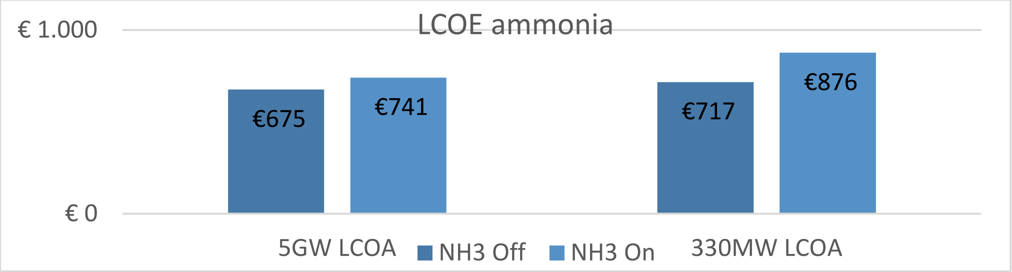


Figure 42: LCOE of ammonia in €/ton. The LCOE for the electric system in the various cases (in €/kwh from left to right is: 0.03, 0.021, 0.014 and 0.011).

Methanol

Figure 43 shows the outcomes of the LCOE in €/ton for the methanol cases. Onshore methanol production seems economically less preferable on this LCOE basis. This can for a great extent be explained by the fact that costs are not included for harbour infrastructure (refuelling etc.) and no cost factor is applied. It is very unlikely that the LCOE for offshore production remains more positive when this offshore cost factor is applied. Moreover, one should be careful with the interpretation of the data, at a higher LCOE for methanol goes hand in hand with an lower LCOE for the electrical part of the system.

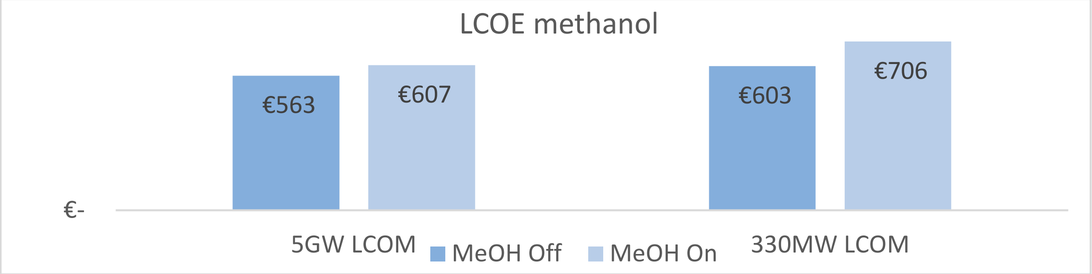


Figure 43: LCOE of Methanol in €/ton. The LCOE for the electric system in the various cases (from left to right is: 0.03, 0.021, 0.014 and 0.011).

CO_2 price

CO_2 supply enters the system boundaries as an exogenous variable (tons of delivered CO_2). The supply could be sourced from e.g. direct air capture or industrial sector. Although, the direct location from where the CO_2 originates is out of the scope of this study, a sensitivity analysis is included to account for related costs for CO_2 transport/utilisation in the amount of €-30 to €120 per ton of CO_2 transported. Negative CO_2 prices consider a carbon utilisation scenario where a fee for consumption is considered. The outcomes of the sensitivity is given in Figure 44. A 10€/ton increase (decrease) in CO_2 price increase (decreases) LCOM by about 5%. There is no break-even point realised within the current range of CO_2 prices. The NPV of the 5GW methanol case decreases with 175 million euro per 10€/tonne CO_2 increase in CO_2 utilisation cost.

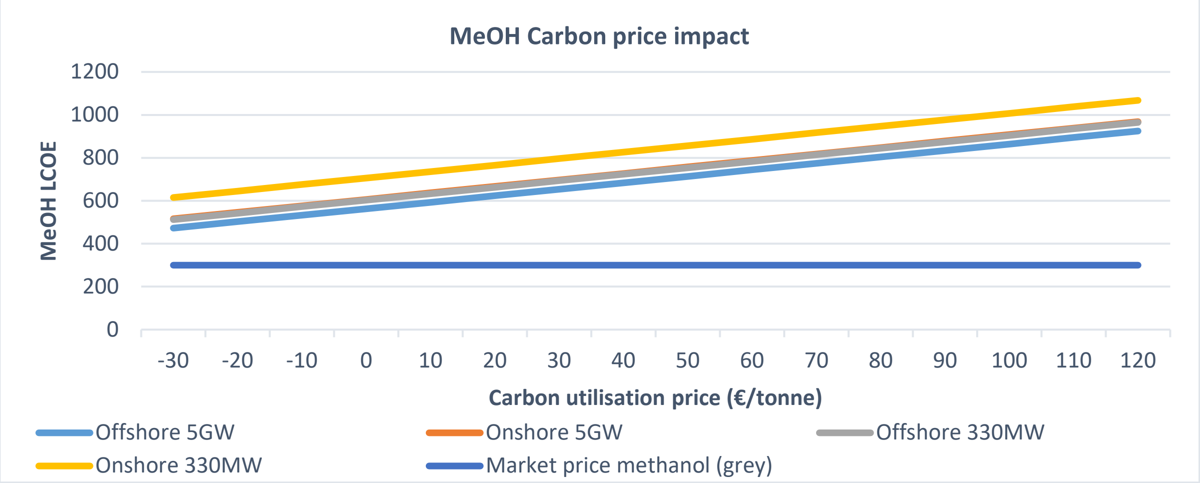


Figure 44: Sensitivity Power-to-Methanol for CO_2