North Sea Energy

Carbon footprint of grey, blue and green Hydrogen

As part of Topsector Energy:
TKI Offshore Wind & TKI New Gas

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Executive summary

The aim of this study is to compare the environmental performance of grey, blue and green hydrogen production options – for both onshore as offshore locations. A screening level life cycle assessment (LCA) focusing on greenhouse gas (GHG) emissions, also referred to as carbon footprint is used for this purpose. In the LCA described here, 1 MJ of hydrogen at 68 bar and at the Dutch shore was chosen as the functional unit for comparison. All hydrogen was assumed to have quality sufficient for at least energy generation and storage.

The specific technologies and scenarios taken into consideration were: hydrogen production by (proton exchange membrane (PEM) and alkaline electrolysis offshore, by alkaline onshore and by natural gas reforming via steam methane reforming (SMR) and autothermal reforming (ATR) onshore. For SMR and ATR options with and without carbon capture and storage were included. In the analysis, renewable electricity from offshore wind was assumed for electrolysis whereas electricity from the Dutch grid for SMR and ATR. Electrolysis carbon footprints are about 0.01 kg CO_2eq/MJ – similar to the results reported by Simon & Bauer (2011) and Bhandari et al., (2012). SMR carbon footprints reported by the same authors were about 0.1 kg CO_2eq/MJ – 0.09 kg CO_2eq/MJ in our graph. ATR had a higher footprint than SMR due to the extra electricity use for air separation (oxygen production). In line with literature we find higher footprints for SMR and ATR than for electrolysis using electricity from offshore wind.

However, in line with literature, sensitivity analysis results indicate that electrolysis is not per definition the ‘greener’ technology. If instead of renewable electricity, the national grid is used as electricity source, electrolysis with alkaline has a higher carbon footprint than SMR and ATR. With use of CCS, SMR carbon footprints become comparable to electrolysis. For ATR this is only the case, if renewable electricity is used for air separation.

We found that the primary energy source has been confirmed as very influential for carbon footprints. This has two consequences: on the one hand, almost all carbon footprints (not related to natural gas) can be expected to decrease in time if electricity mixes become less carbon intensive. On the other hand if electricity sources don’t develop as expected or are less available, greenhouse gas emissions can be higher than expected.

Finally, from an environmental point of view, onshore production of hydrogen seems preferable. In general, differences are small, but the proximity to other users onshore can provide benefits by re-using heat and oxygen. Electricity use for oxygen provision was an important contributor to the carbon footprint of ATR, which could be lowered if oxygen is available from electrolysis. The integration of blue (ATR) and green hydrogen production requires further research. NIB (2017) describes these types of synergies for other industries, e.g. using oxygen for biomass gasification.

Abbreviations

ATR – AutoThermal Reforming
CO_2 eq – Carbon dioxide equivalents
GHG – GreenHouse Gas
LCA – life cycle assessment
PEM – Proton Exchange Membrane
SMR – Steam Methane Reforming

1 Introduction

Energy transition and climate goals increase the need for alternative energy carriers. Preferably energy carriers that are potentially low carbon and can be easily stored. These energy carriers allow flexibility throughout the transition path, particularly in early stages. Pressures on available space and current business cases also increase the demand for integration of divers functions in the (Dutch) North Sea. In particular natural gas production and generation of electricity by wind farms could potentially share functions and infrastructures.

Hydrogen is advertised as energy carrier that could play a significant role in our energy system. It is a low carbon-free energy carrier that could buffer the intermittency of renewable energy sources. It also has favorable energy storage characteristics over electricity storage, especially for longer duration. Meanwhile, hydrogen could also play a role as transition fuel by connecting current and future energy infrastructure. Additionally, hydrogen in the North Sea could provide synergies with gas and wind, such as shared infrastructure and resources.

Many plans for roll-out of hydrogen in the Netherlands exist (e.g. NIB, 2017; Gigler & Weeda, 2017). The report 'net voor de toekomst' states 'hydrogen is indispensable in the future energy supply'. It envisages a role not only for electricity generation but also for transport, heat and industrial feedstock. Gas pipelines should be re-used then also for hydrogen and other gasses (NSE 1 Klimaatwinst op de Noordzee door systeemintegratie, North Sea Energy, 2018). Hydrogen is seen as a transition fuel not only because it is expected to make use of existing gas infrastructure, but also because it can be produced from fossil (via reforming of natural gas, referred to as grey hydrogen) as well as renewable (via electrolysis from e.g. wind electricity, referred to as green hydrogen) sources. Also, carbon capture (and storage, CCS) could be used to make grey hydrogen less CO_2 emission intensive, an option referred to as blue hydrogen. There are also several roadmaps to make use of North Sea gas fields for carbon storage (extensively reviewed in North Sea Energy programme WP1.4 Alignment CCUS Roadmap).

The combination of gas, electricity and hydrogen production as well as the proximity to potential carbon or energy storage fields has opened up the discussion whether hydrogen can most preferentially be produced onshore or offshore. The economic analysis of this discussion (as well as other gasses from power) are also addressed in WP3.4 Power to liquids and in NSE 1 (Jepma et al., 2018). There it was concluded that, green hydrogen production could become feasible from a system perspective when integrating various economic externalities and adapting scale via modular stacking. Blue hydrogen production on a platform was deemed less economically attractive due to economies of scale advantages onshore, however, offshore blue hydrogen production also has some inherent advantages, especially related to distance to gas source and CO_2 sinks that could prove to have an attractive business case in the future (NSE 1 Klimaatwinst op de Noordzee door systeemintegratie, North Sea Energy, 2018; Tulloch, 2019).

Off course, electrolysis for hydrogen production is a technology that can also be performed without a dedicated electricity source, so using the mix of sources in the national grid. Intuitively, the greener the source, the lower the carbon footprint of the hydrogen. However, specific sources, technologies or locations might make a difference.

To make sure that hydrogen does indeed contribute to reducing greenhouse gas emissions, the different options should be assessed beforehand, taking a life cycle perspective to prevent trade-offs in time or space. The aim of this study is to compare the environmental performance of grey, blue and green hydrogen options – onshore and offshore were appropriate. A screening level life cycle assessment (LCA) focusing on greenhouse gas (GHG) emissions, also referred to as carbon footprint is used for this purpose. The details of the method are explained in Chapter 2, the results are presented in Chapter 3.

2 Hydrogen production pathways

Hydrogen can be produced via divers technologies and a range of sources, including fossil and non-fossil ones. Bhandari et al. (2012) distinguish hydrogen production pathways by type of source: hydrogen from fossil sources, from biomass and from water.

Main production pathways are electrolysis (from water requiring electricity), bio(chemical) conversion and thermochemical conversion and conversion from sunlight[1]. Thermochemical conversion includes reforming gaseous (such as natural gas) and light liquid (generally but not by definition) fossil sources. Another pathway is the gasification/partial oxidation for solid fuels such as coal and biomass (Simbeck and Chang, 2002). These thermochemical pathways yield carbon (CO_2) as by-product from hydrogen production. The CO_2 formed could be captured, transport and stored (CCS) to lower the carbon footprint of production.

Considering the availability of energy sources in the North Sea and the scope of the North Sea energy project on system integration, production from natural gas (also with CCS) and using wind electricity for electrolysis of (desalinated sea) water are the most interesting options to investigate in this context.

Electrolysis can be performed with three main technologies: alkaline cells, Polymer electrolyte membrane (PEM) and Solid Oxide electrolysis cells. The last, however, is still under development (Bhandari et al., 2012; Haefele et al., 2016), leaving alkaline and PEM as the major short term options, as has also been considered in previous NSE reports (Jepma et al., 2018). Jepma et al also describe the advantages and disadvantages of PEM and alkaline. Alkaline is a technology available at larger scales. Therefore, considering the current technology status, we expect it to be the technology of choice onshore. However, PEM has advantages in terms of spatial footprint (i.e. m^2 /kWe), flexibility and ability to deal with intermittency. Therefore, this technology is included for offshore cases.

For producing hydrogen from natural gas, there are also three main routes:
- Steam methane reforming (SMR)
- Authothermal reforming (ATR)
- And partial oxidation (POX)

SMR is currently the most common method of producing hydrogen from gas (Mulder et al., 2019). However, ATR is often stated to be most technological and economic advantageous (e.g. Partenie et al., 2019). POX is excluded as it is used much less in practice (Van Capellen et al., 2018).

LCA studies have been performed for these production pathways for hydrogen. These results have to be confirmed and updated for the situations relevant within the North Sea Energy program, they also have to be adapted to the local situations in comparing onshore and offshore conditions (to our knowledge not performed previously), differences in distance and local energy sources.

[1] https://hydrogeneurope.eu/hydrogen-production-0

3 Methods

3.1 Goal and scope

A general description of life cycle assessment has been provided in NSE 1 and is included in Appendix I. In short, as the name says, the total life cycle and all according emissions and research extraction are intended to be included. LCA encompasses four stages (goal and scope definition, data inventory, impact assessment and conclusions and recommendations). Next to methods that strive to be as complete as possible in their coverage of potential environmental problems, also specific problem categories (so called single issues) can be addressed – with the carbon footprint being by far the most applied.

In the LCA described here, 1 MJ of hydrogen at 68 bar and at the Dutch shore was chosen as the functional unit for comparison. Using energy content rather than mass as functional unit for LCAs comparing hydrogen production technologies has advised by the guidance document for performing LCAs on hydrogen (Lozanovski et al., 2011). All energy contents reported in this report are lower heating values. Although hydrogen by electrolysis is by definition of higher purity compared to hydrogen from gas, all hydrogen was assumed to be of quality appropriate to fulfil functions as energy generation and storage. The specific technologies and scenarios taken into consideration are shown in Table 1. All electricity required for electrolysis, including auxiliary processes, such as hydrogen compression, was modelled to come from wind electricity. For gas reforming (grey and blue) all sources were modelled to be ‘grey’, meaning electricity for auxiliary processes was taken from the national grid.

Table 1. Technologies and locations investigated for green, grey and blue hydrogen production.

	OFFSHORE (60km from shore)	ONSHORE
Electrolysis	Alkaline Polymer electrolyte membrane (PEM)	Alkaline
Natural gas reforming		Steam methane reforming (SMR) Autothermal reforming (ATR)
Natural gas reforming with carbon capture and storage		SMR with CCS ATR with CCS

As sensitivity scenarios additional alkaline onshore using electricity from the grid and SMR and ATR using wind electricity wherever required were analysed. To measure the impact of distance, an offshore electrolysis at 300km from shore was also modelled separately.

The impact category assessed was the carbon footprint – the GHG over the life cycle expressed in kg CO_2eq by using the 100 year GWP from the 2013 Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) to translate all GHG to a comparable unit.

The system boundaries encompassed the production of natural gas and generation of electricity from wind, the production of hydrogen, compressions of hydrogen for transport or to the level of the functional unit, the transportation of gas, electricity and/or hydrogen and, where appropriate, the capture and storage of CO_2 emissions. Technology representativeness is current. Infrastructure (e.g. the contribution of electrolyser materials to the hydrogen life cycle impacts) was not taken into account, except for pipelines and electricity cables. Pipelines and cables were considered of specific interest in this project due to possible differentiations between onshore and offshore.

3.2 Inventory

An overview of the main inputs and processes is shown in Figure 1. Technologies, data sources and assumptions are described in detail below. The life cycle inventory database Ecoinvent 3.3 (Wernet et al., 2016) was used to translate data on materials and energy into environmental profiles (GHG emissions). Electricity from the Dutch grid is directly taken from Ecoinvent (0.6 kg CO_2eq/kWh).

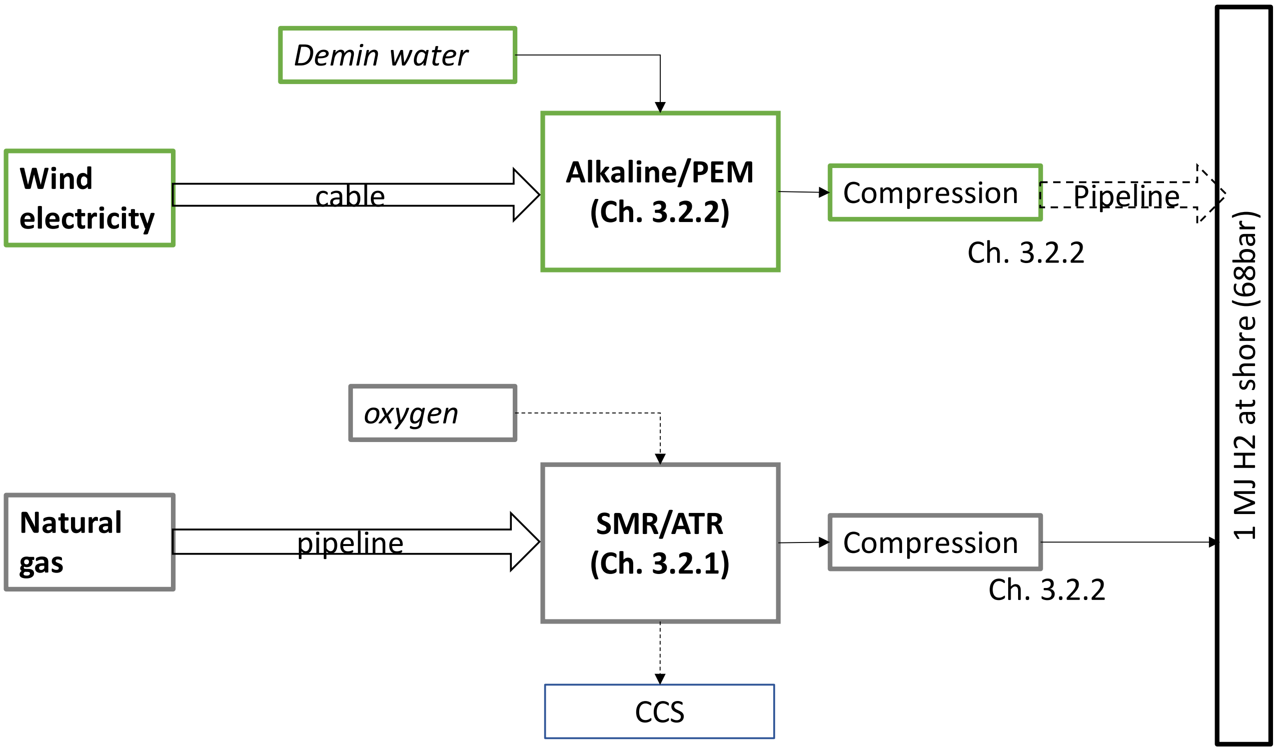

Figure 1. Main inputs (no side products) and flows for green, grey and blue options (as indicated by colored boxes). Dashed lines indicate that this process is included for some, but not all scenarios, e.g. pipeline for electrolysis is only included for offshore PEM, oxygen is only required for ATR.

Inputs from NSE 1

Production of wind and natural gas are taken from NSE1 (Hauck, 2018), where an LCA on platform electrification was performed. The research showed carbon footprint advantages of gas produced with platform electrification compared to fuel gas. Carbon footprint of wind electricity was estimated about 0.01 $kgCO_2eq/kWh$ and the one of natural gas about 0.12 kg CO_2eq/m^3. Transport of natural gas to shore is taken unaltered from Ecoinvent.

For offshore electrolysis a distance of 20km from wind park to the electrolyser location is assumed in line with the assumptions on platform electrification in NSE1. Production of wind in the wind farm includes transformation to high voltage. For electrolysis onshore, wind electricity is transmitted to onshore. Transmission losses that are taken to be 0.5% in line with WP3.4 Power to liquids.

3.2.1 Hydrogen from natural gas

In SMR and ATR, hydrocarbons from natural gas with air and steam (heat) are converted in reforming tubes (catalyst) to carbon monoxide and hydrogen. With water shift reaction the carbon monoxide can be converted to CO_2. In ATR, instead of air, pure oxygen is used, enabling to provide part of the required heat by internal combustion of part of the natural gas. Additionally, output gas streams are more pure, making separation of CO_2 easier.

Hydrogen production from natural gas was modeled based on a paper by Salkuyeh et al. (2017). Inventory data for the systems are shown in Table 2. Output pressures are understood to be 25bar, and yearly production 165,564 ton/a. These data include CO_2 separation and liquefaction (for the cases with CCS). The carbon capture rate calculated from the source was 95% for SMR and 100% for ATR. Carbon dioxide is removed by amine separation.

Table 2. Inventory data for SMR and ATR with and without CCS (from Salkuyeh et al., 2017)

		SMR w/o CCS	SMR with CCS	ATR w/o CCS	ATR with CCS
Output					
H2	MJ (25bar)	1	1	1	1
Inputs					
natural gas	m3	0.047	0.064	0.046	0.047
Oxygen	kg	0	0	0.027	0.055
CO2storage	kg	0	0.11	0	0.085
Emissions					
CO2	kg	0.083	0.007	0.082	0.000
Heat	MJ	59	125	54	59

3.2.1.1Production of natural gas

3.2.1.2Oxygen separation

Electricity use for air separation was taken from ecoinvent (ca. 1 kWh/Nm^3). Oxygen specific power use for air separation is reviewed by Alsultanny and Al-Shammari (2014) and averages were around 0.6/0.7 kWh/Nm^3 for three specific air separating units. To account for possible overestimation of the electricity need in our model, we also included a sensitivity scenario with the lowest number in the range (0.6kWh/Nm^3).

3.2.1.3Carbon Capture and Storage

Carbon transport and injection was modelled based on Koornneef et al. (2008), using their assumptions on pipeline and capture facility lifetime (30 years), see Table 3. It should be kept in mind that this study assessed underground storage, but has been chosen for data availability reasons.

Table 3. CCS characteristics per kg CO2 captured from Koorneef et al. (2008)

CO2 transport		
Losses	kg CO2/kgkm	2.8E-04
CO2 injection		
compression energy	kWh/kg CO2	0.007

3.2.2 Electrolysis

In water electrolysis, electricity is used to split water into hydrogen and oxygen. Alkaline electrolysers is the most used and matured form. The name stems from the solution that is used to allow separation of oxygen and hydrogen ions. In PEM, a solid polymer membrane is used to transport protons.

The electrolysis systems are characterized by water and electricity requirements. The performance data are taken from Tractebel, Hinicio for FCH-JU (2017) and internal discussions within the NSE 3 consortium for 20MW systems in 2017 (shown in Table 4). Data include electricity transformation and rectification. Yearly production numbers are used to re-calculate pipeline and compression energy needs, originally derived on a yearly/lifetime basis to per MJ data. The underlying assumption is that each system can be scaled linearly to the required output. Oxygen output was modelled as 8kg per kilogram of hydrogen produced, heat output as 1- efficiency from energy input. More details on the pipelines required are shown in Appendix II.

Table 4. Inventory data for electrolysis by PEM and alkaline (per MJ hydrogen produced)

	UNIT	PEM	ALKALINE
Electricity consumption	kWh/MJ	0.41	0.39
Water consumption	l/MJ	0.13	0.13
Production	kg/y	181,034,483	205,882,352
Output pressure	bar	30	15
Oxygen output	kg/kg	*Not modelled	0.67
Heat output	MJ/MJ	*Not modelled	0.4

*PEM is only considered in the offshore situation and has very limited synergy options for produced oxygen and heat. It is therefore not modelled further.

3.2.2.1Desalination

An electricity use of 0.004 kWh per liter is included in the model based on information from WP 3.4 Power to liquids.

3.2.3 Hydrogen transport and compression

Several hydrogen transport and compression scenarios are taken into account. For an equal comparison the hydrogen is delivered onshore and compressed to 68 bar. Output pressures at production locations are as described above. Pipeline input pressures and pressure drop been taken from WP3.4 Power to Liquids. An overview is given in Table 5. Energy requirements for compression have been derived from the differences of input (of compression) and output pressures, see appendix 2 for details of calculations and values.

Table 5. Pressures at different locations and scenario's.

	PEM	Alkaline	SMR	ATR
Location	Offshore	Offshore	Onshore	Onshore
Output pressure H2 production	30	15	25	25
Compressor output pressure – into pipeline 60 km	70	70		
Compressor output pressure – into pipeline 300 km (sensitivity scenario)	73	75	-	-
Final pressure at shore (from pipeline or compressor at shore)	68	68	68	68

3.2.4 Sensitivity analysis

Several sensitivity analyses and scenarios were performed in this study. Some have already been introduced in previous paragraphs. All of them are summarized below:

- For PEM and alkaline electrolysis wind electricity was used for all processes (including desalination and compression). In a sensitivity scenario for alkaline onshore, grid electricity is used for all processes (except for water that in this scenario is assumed to be is bought and not desalinated on spot).
- For both SMR and ATR grid electricity is used by default, but in the sensitivity analysis wind electricity is used for compression, oxygen separation from air (only ATR) and CCS.
- Calculations have been performed for a distance from shore for the offshore production locations of 60km. In a sensitivity analysis also a distance of 300km is used.
- Next to the values from ecoinvent, a value of 0.6kWh/Nm^3 oxygen (instead of 1 kWh/Nm3) has been applied for air separation (oxygen production) based on the review by Alsultanny and Al-Shammari (2014).
- A carbon capture rate for ATR with CCS of 100% seems very high. Calculations have therefore been repeated for a capture rate of 94% based on Partenie et al., 2019,. Although 100% seems extremely high, we use this number in the base case to derive the base case form one consistent source.
- Electrolysis also produces oxygen and heat as by product; SMR and ATR generate waste heat. These have been left out of scope in the main analysis. However, in the sensitivity analysis these are considered valuable by-products (see inventory Tables 2 and 4 for values). In the onshore alkaline case we have

modelled the co-produced oxygen to replace conventional liquid oxygen production. For the heat co-production we have modelled to replace heat from natural gas for district or industrial heating (central or small also available). These processes are directly taken from the ecoinvent database.

4 Results

Comparison of the results in the baseline scenarios (alkaline and PEM electrolysis offshore, alkaline electrolysis onshore and PEM and ATR with and without CCS onshore) are shown in Figure 2. Error bars are used to show the influence of using lower electricity requirements for air separation (higher carbon capture rate) and a higher carbon capture rate for ATR (lower error bar). Outcomes for 300km instead if 60km are insignificant and don't show up in the figure. ATR without CCS decreases by almost 10% and ATR with CCS by around 30% (to about 0.03kg CO_2eq/MJ) if less electricity is needed for air separation. Less carbon capture with ATR increases emission by less than 10%.
Differences between electrolysis variants are related to the following sources:

- Footprint of alkaline onshore is higher due to longer transportation distance for electricity from wind farms and therefor more cable needs (and electricity losses). Differences are not related to differences in compression because compression energy for both cases is almost equal (see also Table A2 in Appendix II).
- The fact that PEM carbon footprint is slightly higher than alkaline is related to the fact that alkaline uses slightly more electricity (see Table 4).

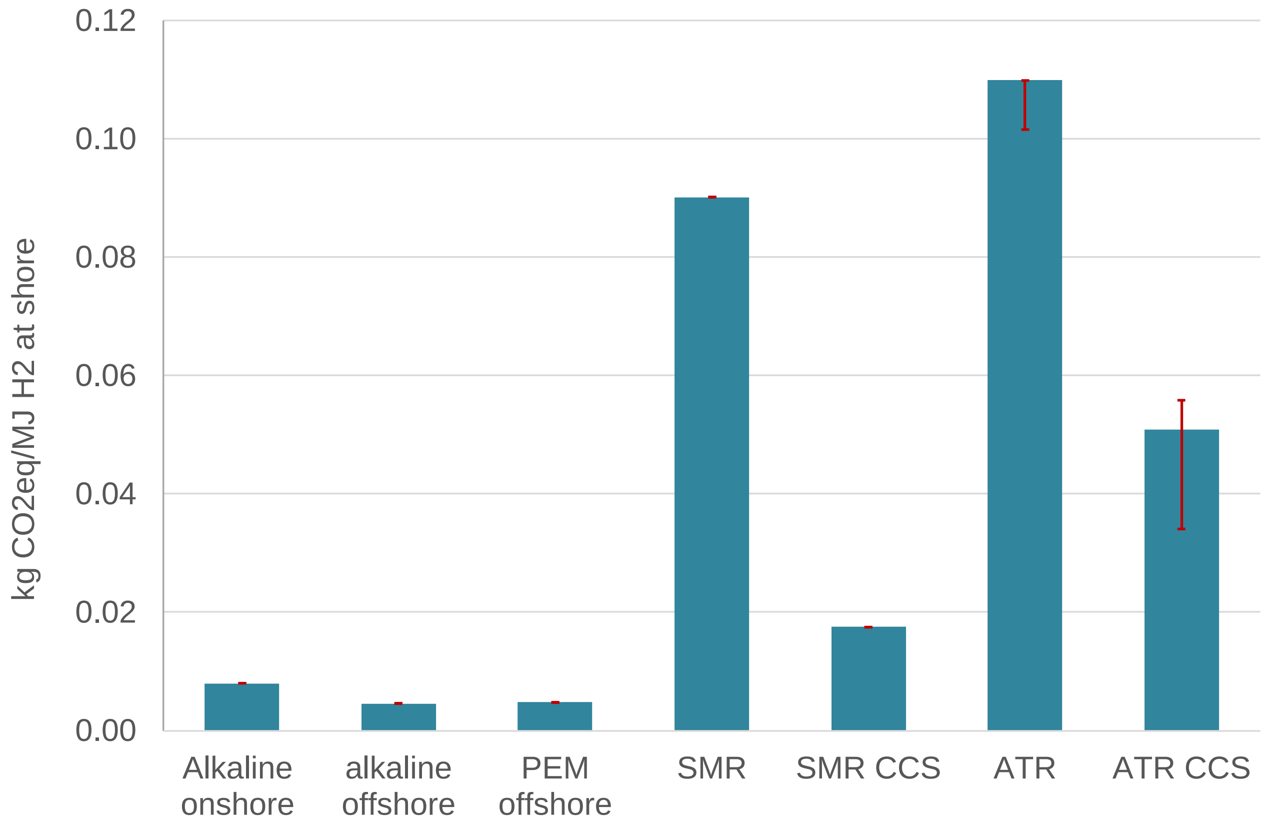

Figure 2. Comparison of the life cycle GHG emissions of hydrogen production options.

Electrolysis carbon footprints are about 0.01 kg CO_2eq/MJ – similar to the results reported by Simon & Bauer (2011) and Bhandari et al., 2012. SMR carbon footprints reported by the same authors were about 0.1 kg CO_2eq per MJ; this is 0.09 kg CO_2eq per MJ in our results. ATR without (w/o) CCS had a higher footprint than SMR due to the extra electricity use for air separation. Table 6 shows the contribution of different processes to the total carbon footprint of SMR and ATR. Generally, direct process emissions were most important. For ATR about 20% of the carbon footprint were related to electricity use for air separation. For ATR with CCS electricity use was the main contributor to the carbon footprint. Electrolysis impacts are dominated by electricity use for the electrolysis itself in all cases and are therefore not shown. The carbon footprint of wind electricity in NSE 1 was about 0.01 kgCO_2eq/kWh.

Table 6. Contribution to carbon footprint for ATR and SMR (kg CO_2eq/MJ)

	Direct emissions H2 production	Natural gas production	Oxygen separation	CCS
ATR w/o CCS	0.082	0.006	0.021	na
ATR with CCS	0	0.006	0.043	0.001
SMR w/o CCS	1.000	0.006	na	na
SMR with CCS	2.000	0.009	na	0.002

Figure 3 shows the results of the sensitivity analysis for energy sources: using wind electricity for gas reforming technologies (green ATR and SMR) and grid electricity for alkaline onshore (grey alkaline). Comparing Figure 2 and 3 shows that mainly the carbon footprint for ATR with CCS decreases. This is due to the fact that for this technology, use of electricity played role for the carbon footprint, whereas for SMR only direct process emission were important (see Table 6). For alkaline with electricity from the grid as energy sources, the carbon footprint increases to 0.23 kg CO_2eq/MJ, which is in line with Simons and Bauer who reported 0.28 kg CO_2eq/MJ.

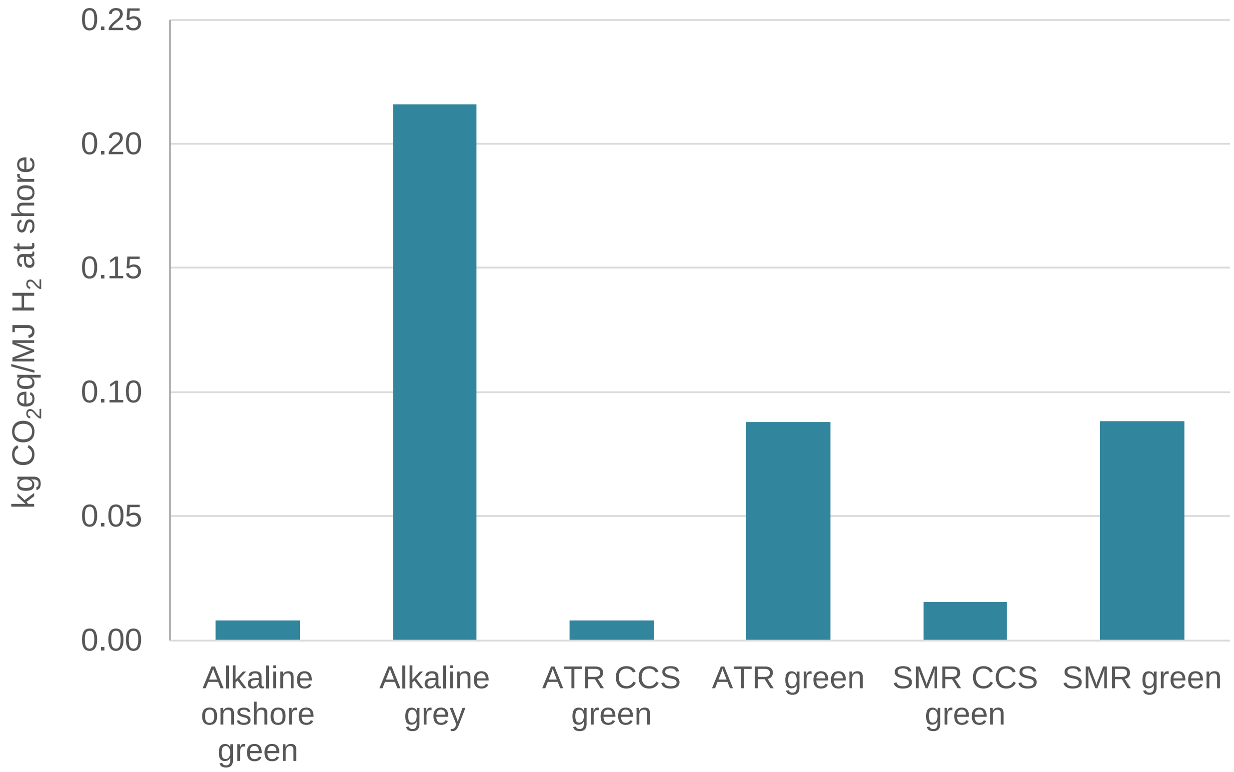

Figure 3. Carbon footprint results for ATR and SMR if wind electricity is used instead of electricity from the grid. Green alkaline is shown for comparison only.

Table 7 shows the carbon footprint for alkaline onshore as well as SMR and ATR, if credits are given for oxygen and heat output. This means, they are modelled as products that are sold to the market and could replace heat by natural gas or liquid oxygen. In all cases, the carbon footprint becomes negative or about zero, indicating in fact the net reduction of environmental pressure. Counterintuitively, this credit is highest for SMR with CCS – the process with the lowest efficiency and thus the highest heat losses. These results indicate that the environmental impacts related to hydrogen production in this case are lower than the impacts related to the combustion of natural gas. It should be kept in mind that these results are a first indications because general processes from ecoinvent are used for replaced heat, whereas gas provision for SMR and ATR has been modelled in NSE 1 specific for the Dutch situation. Moreover, all heat is assumed to be used to replace heat by natural gas which are optimistic assumptions. Though, it indicates that apart from the chosen production process, the geographical locational of blue hydrogen production and more specifically, the integration with other functionalities is of great importance for the environmental impact.

Table 7. Carbon footprints for alkaline onshore, SMR and ATR with and without CCS if credits are given to oxygen and heat output.

Unit	Alkaline onshore	SMR	SMR CCS	ATR	ATR CCS
kg CO2 eq/MJ H2	0.0	-1.9	-4.2	-1.7	-1.9

5 Discussion and conclusions

In line with literature we find higher footprints for SMR and ATR than for electrolysis using electricity from offshore wind. However, also in line with literature, results of the sensitivity scenario indicate that electrolysis is not per definition the ‘greener’ technology. If instead of wind, the national grid is used as electricity source, electrolysis with alkaline has a higher carbon footprint than SMR and ATR. With use of CCS, SMR carbon footprints become comparable to electrolysis. For ATR this is only the case, if wind electricity is used for air separation. Electricity use for air separation taken from the LCI database was in the range reported in the review by Alsultanny and Al-Shammari (2014). However, it should be kept in mind that the value of this electricity use is very important when comparing ATR and SMR.

A number of shortcomings should be kept in mind when analysing the results of this study. Most importantly, life cycle inventory data represent the current state of technologies at best. Due to the time it takes to gather and implement relevant data, they even tend to be slightly behind actual best practices. In our case, this is particularly relevant for emissions related to electricity coming from the Dutch grid. Ecoinvent life cycle emission factors were used for grid electricity: 0.6 kg CO_2eq/kWh (medium voltage). This is the most accepted life cycle inventory database in Europe. These life cycle data represent the total life cycle of electricity production, including provision of fuel and infrastructure and imports of electricity. These data refer to 2012. The most recent ‘Klimaat en Energieverkenning’ of PBL reports and emission factor for electricity production of 0.34 kg CO_2/kWh for 2019, which refers to the electricity generation phase only. Excluding upstream contribution and imports brings the ecoinvent emission factors close to those of the PBL report. This indicates that our results could be overestimated (in the near future) for ATR and alkaline with grid electricity, bringing ‘grey’ alkaline electrolysis closer to other technologies and possibly making ATR more favourable.

Secondly, this report was intended to provide a screening level LCA for divers hydrogen production options related to the Dutch North Sea. It was not intended to provide a detailed comparison of ATR vs. SMR or PEM vs. Alkaline. A wide range of technologies is available for both options as for instance investigated in the H-Vision project (see Partenie et al., 2019). If specific choices are to be made, a more detailed environmental analysis is recommended; also taking into account the required materials for process equipment and other infrastructure elements.

Thirdly, sensitivity shows that geographical location (onshore vs offshore), and especially, re-use of waste heat could be very relevant for the environmental footprint. The sensitivity scenario where heat loss is modelled as valuable by product is based on a first rough estimation based on current Ecoinvent databases. Differences in the end-use possibilities of the heat output (match with capacity, process profiles, temperature levels etc) were not taken into account. Nevertheless, the results indicate that synergies with other related technologies should be explored further.

Further, it is plausible that exact offshore locations are not very influential for environmental footprints. The only differences taken into account between different transportation distances where the differences in electricity consumption for compression. However, often infrastructure has a small influence on the total life cycle impact per functional unit. Other environmental effects of offshore hydrogen production, such as ecological impact, are not analysed here[2].

Finally, a number of conclusions can be drawn from the LCA presented in this report:

- The primary energy source has been confirmed as very influential for carbon footprint. This has two consequences: on the one hand, almost all carbon footprints (not related to natural gas) can be expected to decrease in time if electricity mixes become less carbon intensive. On the other hand if electricity sources don’t develop as expected or are less available, greenhouse gas emissions can be higher than expected.
- From an environmental point of view, differences between locations were are small, but the proximity to consumers of by-products onshore can provide benefits by reusing heat and oxygen. Electricity use for

[2] More information on the ecological impact of offshore hydrogen production can be found in NSE2, Hybrid offshore energy transition options - The merits and challenges of combining offshore system integration options (2019)

oxygen provision was an important contributor to the carbon footprint of ATR, which could be lowered if oxygen is available from electrolysis. These options require further research. NIB (2017) describes these types of synergies for other industries, e.g. using oxygen for biomass gasification.

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7 Appendix I Life cycle assessment

Life cycle assessment (LCA) is a method to systematically quantify and compare the effects of a product, system, service or geographical entity. As the name suggests an important characteristic of LCA is that it takes into account the complete life cycle of a product (cradle-to-grave) from resource extraction to waste treatment, including transport in between. In some cases (e.g. if the environmental performance of a company making consumer products is assessed), the analysis is constrained to the production phase (cradle-to-gate). Another important characteristic of LCA is that a wide range of environmental problems can be addressed, such as climate change and toxicity to humans or ecosystems. This way, trade-off between life cycle stages and/or environmental problem areas are prevented. Finally, LCA is generally considered a comparative rather than an absolute tool. LCA is generally conducted in four interrelated steps: 1) Goal and scope definition; 2) life cycle inventory; 3) impact assessment; 4) interpretation and conclusions (ISO 14040/44.)

In the goal and scope definition, where the products to be compared are defined, the functional unit, the type of LCA, system boundaries, and impacts and impact assessment methodology are set. A functional unit is the unit of comparison to which all flows in the inventory are related. It is important that the functional unit is defined in such way that all systems under comparison fulfill the same function. For comparison of natural gas production, this is generally 1 m^3 of gas, for electricity generation 1 kWh. The type of LCA refers to attributional vs. consequential LCAs. In attributional LCAs, it is assumed that a small amount of the product under consideration would not change the economy and average data are used. In consequential LCA, the change that the production of an additional amount of a product would infer to the economy (e.g. by replacing a competing product) is considered. Data gathering in this case includes modelling of the market consequences.

Inventory refers to the data gathering phase, were all inputs and outputs of the product system are compiled. These encompass resources extractions as well as emissions into the environment and are summarized under the term interventions. For the production of gas, this means that not only direct energy use and emissions during gas production are taken into account, but also the platform materials and energy use for drilling and platform commissioning and decommissioning. To transfer these inputs to 1 m^3 of gas, one has to know, how much gas is produced over the platform lifetime.

Impact assessment describes the phase, where the long list of interventions is translated into a number of so-called midpoint impact categories by modelling the underlying environmental mechanism. This step allows to add all interventions that contribute to the same environmental problem in one common unit. For instance, emissions of greenhouse gases are re-calculated to kg CO_2-equivaltents (CO_2-eq) by using Global Warming Potentials (GWP) that express the contribution of a gas to radiative forcing relative to that of CO_2. For further simplification of interpretation, these midpoint impact categories (often 10 or more) can be translated to endpoints that express the damage these environmental problems cause for Areas of Protections, generally defined as human health, ecosystem health (or biodiversity) and resource availability. Figure 1 gives an overview with examples of these three levels of indicators and their relations. An additional or alternative way of indicator reduction is weighting. In weighting diverse impact categories are weighted according to a perceived relevance to arrive at a single score. This can be derived by monetary valuation using costs caused by the damage or by preventing the emissions in the first place, by policy goals or by preferences derived from surveys under experts or the public. Either way, going from midpoint impact categories to less categories increases uncertainties in these numbers. Finally, another approach to reduce number of indicators, is to focus on a smaller number of impacts that are particularly relevant for a specific research (such as climate change for energy analysis) or that are known to be a good proxy for the whole range of impact categories, such as energy use or one or several resource extractions (energy, land, water, materials).

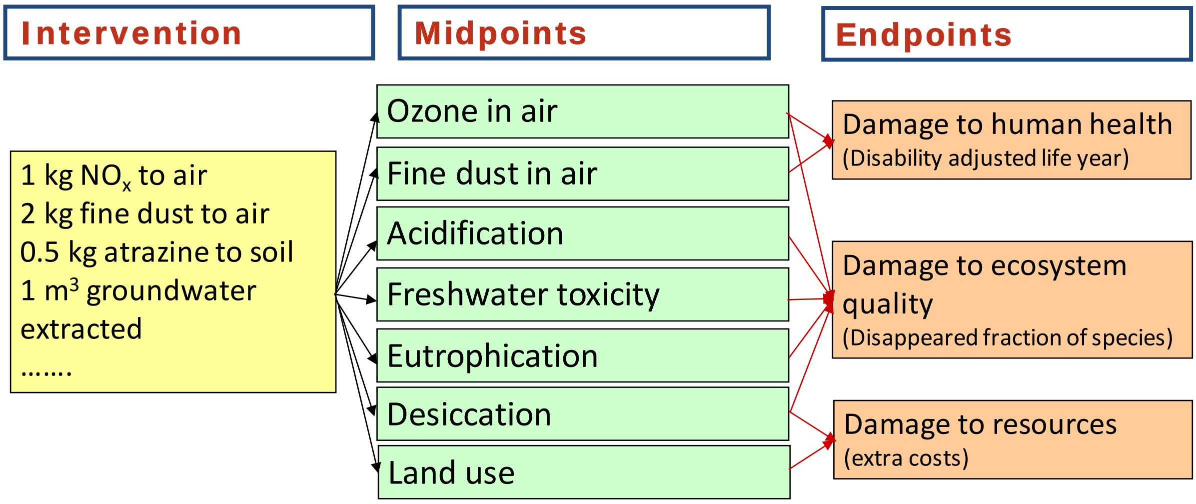

Figure 1. General description and examples of interventions and impact indicators on midpoint and endpoint level in LCA.

Other methodologies than LCA can be used to assess the environmental consequences of an innovation. Environmental assessment (EA, milieueffect rapportage in Dutch) is one of the most famous. EAs are often compulsory when a new works take place. LCA can be applied as a part of an EA (Commissie MER, 2013), depending on the type and goal of the EA. In general, EAs are conducted to assess the effects of specific project (e.g. one new facility) or location (e.g. of a road trajectory). These involve assessment of actual, local environmental effects and knowledge of temporal and small scale spatial changes at the location. Such specific local questions are generally not included in the generic effect of potential damage in LCA. However, if the environmental effects of a whole system, including also indirect effects but on a larger scale, are of interest LCA is a more appropriate tool (within EA or standalone, Tukker, 2000).

8 Appendix II: Pipeline characteristics and energy requirements for compression

Table A1 shows characteristics of the pipelines assumed to transport hydrogen from PEM and alkaline to shore.

Table A1. Pipeline data for electrolysis by PEM and alkaline (per MJ hydrogen produced)

	UNIT	PEM	ALKALINE
Pipeline capacity	kg/h	35000	40000
	m/s	5.5 – 5.6 (60km) 5.3-5.7 (300km)	6.3 – 6.5 (60km) 5.8-6.4 (300km)
Pipeline diameter	inch	24	24

Compression energy per MJ hydrogen transported was calculated from the capacity required for compression (MW), and the flow rate based on the yearly production. The capacity was calculated depending on the differences of input and output pressures:

$$cap = a * \left(\frac{P_i * P_o * C}{M * e} * \frac{n * d}{d - 1} * \frac{P_o}{P_i}^{d-1/d*n} - 1 \right) /1000$$

Where:
Capacity: capacity of compressor (MW);
A: maximum hydrogen output electrolysis (0.59 kg/s)
$P_{i \text{ and } o}$: inlet and outlet pressure compressor (bar)
C: universal gas constant (8.31 J/(mol*K)
M: molar mass Hydrogen (2g/mol)
E: compressor efficiency (75%)
N: number of compressor stages (2)
d: constant diatomic factor (1.4)

Table A2.

Scenario	PEM		Alkaline offshore		Alkaline onshore	SMR/ATR
	60km	300km	60 km	300km	0 km	0 km
Input pressure	30bar		15bar			25 bar
Output pressure	70bar	73bar	70bar	73bar	68bar	68bar
MW	7.8	8.3	16.2	17.6	16.7	8.6
kWh/MJ	0.0032	0.0033	0.006	0.0062	0.0059	0.0038