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Evaluating technology options to mitigate greenhouse gas emissions

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Blue Hydrogen: Beyond the Plant Gate

IEA GREENHOUSE GAS R&D PROGRAMME

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BLUE HYDROGEN: BEYOND PLANT GATES

The primary objective of this study is to review the comparative analysis of blue hydrogen production (that is hydrogen derived from fossil fuels and associated CCS) technologies from oil and oil-based feedstocks as well as the supply chain implication. Further, this study includes techno-economic and life cycle assessments of different technology production configurations in regions that have access to oil resources and potential for the deployment of CCS infrastructure at scale.

KEY MESSAGES

- Analysis in this study highlighted that the total demand for hydrogen could be nearly 2,000Mtoe by 2050. This quantity could be delivered from all sources of hydrogen production, especially from blue hydrogen derived from oil and oil-based feedstocks, while addressing GHG emissions.
- The three blue hydrogen production pathways which use oil-based feedstocks selected for detailed analysis in this study are steam naphtha reforming (SNR) + CCS, partial oxidation (POX) and hygienic earth energy (HEE). These technologies exhibit lower carbon footprints by between 58-67%, 47-77% and 71-78% respectively against the benchmark steam methane reforming (SMR) without CCS in 2020.
- The carbon footprints of all the technologies vary because of regional differences due to the carbon footprint of the feedstock, fuel, and electricity source, and type of technology deployment.
- The total carbon footprint of the selected hydrogen production pathways was heavily influenced by the carbon footprint of the electricity source. This factor underscores the importance of employing low carbon electricity even if a high capture rate is implemented in the production of the blue hydrogen. Changes in the carbon footprint of electricity production was established to have the biggest impact on POX and HEE, to a lesser extent on SNR.
- All the studied oil-based hydrogen production technologies exhibited a higher cost than both the reference grey hydrogen (hydrogen from SMR without CCS) production case and natural gas based blue hydrogen production in the Netherlands via SMR in 2020. However, by 2050, the cost of most of the blue hydrogen pathways from oil-based feedstocks substantially decreases due to larger markets in the oil-producing regions, including to achieve their climate action targets, and economies of scale in hydrogen distribution and CO_2 T&S (transport and storage). If higher carbon prices are applied, blue hydrogen costs will be lower than hydrogen derived from SMR without CCS in the long term.
- In the longer term, the falling cost of renewable electricity and alignment with net zero ambitions is likely to make green hydrogen production increasingly competitive and lower cost than blue hydrogen production in cases where low-cost electricity is available.
- One potential competitive pathway for hydrogen derived from oil and oil-based products against other mainstream alternatives could be achieved if the hydrocarbon feedstock is treated as a waste product (vacuum residue) or assuming it has no inherent economic value (retained within a depleted reservoir).

BACKGROUND OF STUDY

The global demand for hydrogen is about 90 Mt in 2020. It has conventionally been produced from fossil fuel sources with an associated CO_2 emission of almost 900 Mt per year.[1] In light of the shift

[1] International Energy Agency (IEA). Hydrogen. 2021.

towards a low carbon economy IEAGHG has undertaken two parallel studies in 2021 to investigate alternative routes for the decarbonised production of hydrogen. The first, is the 'Low-carbon hydrogen from natural gas: global roadmap' study, which is focused on the hydrogen production technologies from natural gas and secondly, this report, which is based on low carbon hydrogen production from oil and oil-based products as feedstocks. Further, these studies build on the IEAGHG published study on 'Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS' in 2017.

To date, the production of hydrogen from oil and oil-based products has not been investigated in detail despite the well-established process of hydrogen production from hydrocarbon feedstocks. So far, the three major pathways for hydrogen production uses natural gas, coal, or biomass as the primary feedstock. Oil could signify an additional and interesting source of production of hydrogen, bringing potential cost reductions in the blue hydrogen price. Whilst the energy transition would impact oil demand, there is significant infrastructure in place to allow low-cost supply of oil-based feedstocks for hydrogen.

IEAGHG commissioned Element Energy and CE Delft to conduct this study with the aim to review the mature and emerging technologies for various oil-based feedstock and production routes to close the knowledge gap in terms of the environmental impact and techno-economic potential of oil and oil-based blue hydrogen production technologies.

SCOPE OF STUDY

Eight selected hydrogen production technologies, which use oil and/or oil-based products as feedstocks, are reviewed in this study. These technologies with their respective TRLs include catalytic naphtha reforming (9), pyrolysis (4-8)[2], plasma reforming (4), diesel reforming (3-4), HyRes (3-4), steam naphtha reforming (9), partial oxidation (9) and hygienic earth energy (4-6).

Steam naphtha reforming (SNR), partial oxidation (POX) and hygienic earth energy (HEE) were selected for further techno-economic and life-cycle analysis. Both SNR and POX are well established and commercially available technologies for large scale hydrogen production. However, their current deployment for blue hydrogen production, particularly for use with oil-based feedstocks, is still in the early stages of development. HEE's selection was based on the technology being advanced and has the pronounced prospect to produce blue hydrogen from oil-based feedstocks despite currently exhibiting a TRL of 4 - 6.

The potential for oil-based blue hydrogen production in terms of CO_2 transport and storage (T&S) options, feedstock availability and access to hydrogen markets was conducted in fifteen countries across five regions. This encompasses the entire value chain of hydrogen production that include production, conversion, transportation, reconversion, and consumption as schematically presented in Figure 1. The five analysed regions and oil-producing case study countries are:

- Middle East – UAE, Saudi Arabia, Kuwait, Iraq, and Iran
- West Africa – Nigeria, Equatorial Guinea, Gabon, Republic of Congo, and Angola
- North Africa – Algeria and Libya
- Latin America – Brazil and Venezuela
- North Sea region – The Netherlands

[2] The TRL for pyrolysis of oil and oil-based and natural gas feedstocks are currently at 4 and 8 respectively

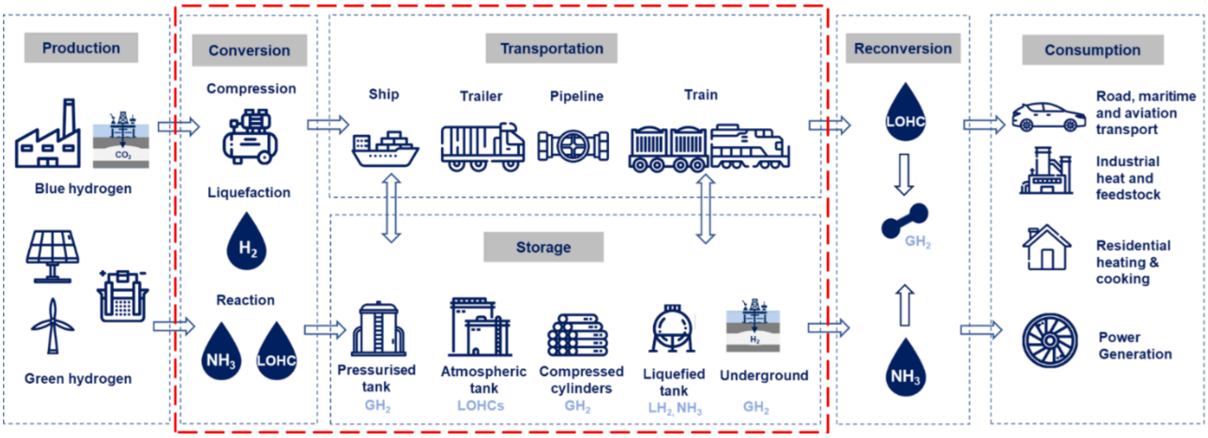

Figure 1. Hydrogen value chain from point of production to end use

Three boundaries for the techno-economic analysis (TEA) considered in this study (Figure 2) as follows:

- **Gateway 1** only accounts for the hydrogen production facility and hydrogen compression.
- **Gateway 2** accounts for the hydrogen production, compression, and the CO_2 T&S facility.
- **Gateway 3** accounts for the entire value for produced hydrogen chain up to the point of end use.

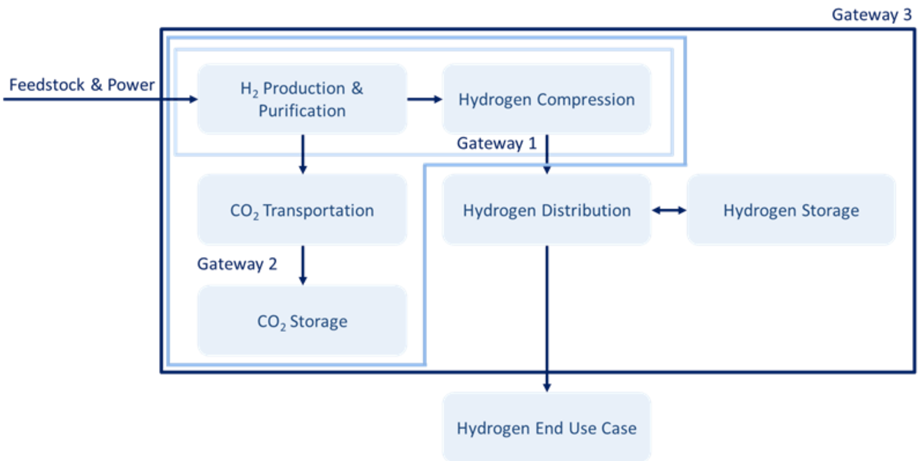

Figure 2. Model cost and emissions gateways

The cradle-to-gate system boundaries are employed in this study, in accordance with the life cycle assessment (LCA) protocol proposed by Valente et al[3]. This boundary system encompasses all process steps from the extraction of the raw materials through to the production of the compressed hydrogen. Therefore, all the processes that are required to produce hydrogen (200 bar, >97% purity) and to transport and sequester the captured CO_2 using CCS are considered (e.g., production of required fuel, feedstock, and electricity).

FINDINGS OF STUDY

Hydrogen demand is generally influenced by the distribution of total energy demand by region, according to the IEA's "World Energy Outlook 2020 – Stated Policies Scenario". However, the relative demand for hydrogen from Europe, North America and Asia Pacific is greater than their respective relative demand for all energy in the IEA's "World Energy Outlook 2020 – Stated Policies Scenario".

[3] Valente et al. Harmonised life-cycle global warming impact of renewable hydrogen. 2017

This is due to their advanced position in developing a hydrogen economy and the increased demand for hydrogen in their respective transport, heat, and power sectors.

Asia Pacific is projected to have a demand of nearly 49% of the global hydrogen supply by 2050, led primarily from strong demand in India and China. North America and Europe are responsible for 18% and 11% respectively by 2050. These are the two other large global markets for hydrogen demand.

The remaining 22% of global hydrogen demand is split between Russia, Latin America, Africa, and the Middle East. However, their demand for hydrogen is expected to become more significant beyond 2050 due to their relative delay in establishing their hydrogen economies.

Emerging and oil-rich regions with the capability to produce low-cost blue hydrogen from oil-based feedstocks are not expected to benefit from large local markets in 2020 and 2030. Instead, their focus should be on exporting hydrogen to those regions with more developed hydrogen markets such as Europe, North America, and Asia Pacific.

In the longer term, hydrogen demand from local markets in these emerging regions could grow exponentially. They would then benefit from at-scale production of blue hydrogen derived from oil and oil-based based products. These production pathways will still have to compete with natural gas based blue hydrogen production as well as emerging green hydrogen production technologies. In the long term, green hydrogen production in regions with access to low-cost renewable electricity from solar and wind (such as Australia, Middle East, and North Africa) are expected to become increasingly competitive.

Three hydrogen production technologies out of the earlier mentioned eight production pathways from oil-based products i.e., SNR, POX and HEE passed the technology screening process based on future technology outlook, diversity of feedstock and data availability criteria used in this investigation. Data on both the CAPEX (capital expenditure) and fixed OPEX (operational expenditure) for SNR uses SMR as a proxy because of limited information about costs associated with SNR and the close alignment between the two processes. Data on the POX CAPEX is currently limited. Cost estimates are based on information from stakeholder engagement and proxies from the literature. For the fixed OPEX, the flat rate of 3.9% of CAPEX is used. Two primary CAPEX scenarios are explored for the HEE. The first scenario assumes that the process is used at a depleted reservoir. The well cost is therefore near zero as existing infrastructure is used. The only capital cost components are the membrane, air separation unit and hydrogen generator. The second scenario assumes CAPEX based on the cost of drilling a new well and other items of capital equipment. The CAPEX and OPEX for the three selected hydrogen production pathways are presented in Table 1.

Table 1. Technology CAPEX and Fixed OPEX for a 300MW production facility – central case, 2020.

Technology	CAPEX (€ / kW_{LHV})	Fixed OPEX (€ / kW_{LHV} / yr)
Partial Oxidation	1,040	40.0
Steam Naphtha Reforming	1,030	36.0
Hygienic Earth Energy	600 / 700	23 / 27

Regional analysis

For all regions, a range of oil based blue hydrogen technologies have been analysed. A broad variation in cost of different technologies in different locations was observed, this is primarily due to the cost of the oil feedstock in a particular location and corresponding cost of hydrogen distribution and storage. Technology choices for each country are not prescriptive and it is likely that many countries would be able to deploy all three oil-based production technologies analysed in this study.

The Middle East:
The LCOH (levelized cost of hydrogen) in the Middle East base case and lowest cost pathways in 2020 are presented in Figure 3. The LCOH for the base case was established to be between 66% and 119% higher than the SMR benchmark. This is due to the high hydrogen distribution costs of shipping to markets in Asia. POX in Kuwait and SNR in Iraq were found to be the lowest and highest cost options in the region respectively.

In the lowest cost pathway scenario, the cost of HEE in Iran was established to be lower than the SMR incumbent by 0.02 €/kgH_2. This is mainly because of the assumption that oil from a depleted well is near zero cost and existing infrastructure can be utilised. The LCOH for POX in Kuwait and Saudi Arabia is reduced by 30% and 28% respectively, where the oil feedstock is assumed to be a waste product. Although this is a significant cost reduction, POX remains 16-31% higher cost than the SMR incumbent. The feedstock costs for Naphtha remain high in the UAE and Iraq, resulting in the LCOH remaining unchanged from the base case in 2020.

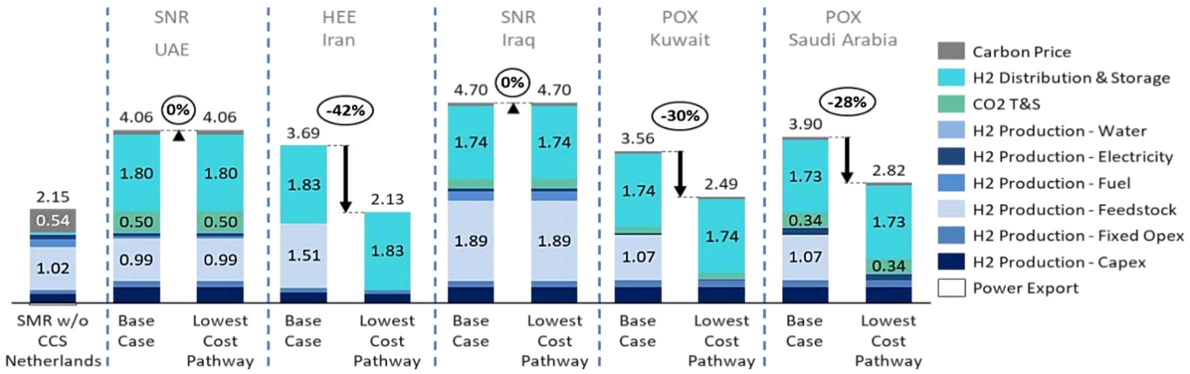

Figure 3. LCOH (€/kgH_2) comparison for base case and lowest cost pathway scenarios in the Middle East in 2020

The LCOH in the Middle East base case and lowest cost pathways in 2050 are presented in Figure 4. In the base case, the LCOH ranges from 2% cheaper to 38% costlier than the SMR incumbent. POX in Kuwait remains the lowest cost option in the base case scenario, whilst SNR in Iraq is the highest cost option. The hydrogen distribution cost component remains high for all countries.

In the lowest cost pathway scenario in 2050, all hydrogen is assumed to be consumed domestically and thus distributed to local users via pipeline. When combined with other favourable sensitivities, this results in a very low-cost pathway for hydrogen production for HEE and POX technologies in the Middle East. HEE in Iran has a LCOH of only 0.26 €/kgH_2, whereas POX in Kuwait and Saudi Arabia are 0.78 €/kgH_2 and 0.97 €/kgH_2, respectively. SNR in the UAE is lower in cost than the incumbent which is significantly impacted by the carbon price in 2050, whereas SNR in Iraq remains expensive due to the higher cost of the Naphtha feedstock.

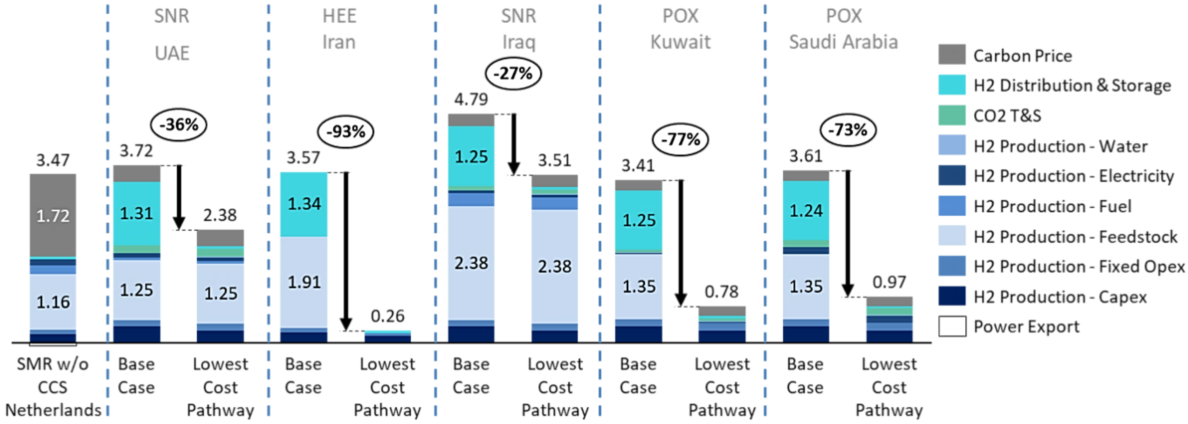

Figure 4. LCOH (€/kgH_2) comparison for base case and lowest cost pathway scenarios in the Middle East in 2050

West Africa:

The LCOH in the West Africa base case and lowest cost pathways in 2020 are presented in Figure 5. The LCOH is 64-182% higher than the SMR incumbent in the base case, this is due to the substantial hydrogen distribution costs that result from shipping to markets in Europe. HEE in Equatorial Guinea and SNR in Angola are the lowest and highest cost options respectively of the countries analysed in this region.

In the lowest cost pathway scenario, HEE in Equatorial Guinea is 8% lower cost than the SMR incumbent. This is mainly due to the assumption that oil from a depleted reservoir is zero cost and existing infrastructure can be utilised. HEE in Nigeria is also found to be cost competitive at only 0.02 €/kgH_2 greater than the SMR incumbent. The LCOH for POX in the Republic of Congo and Gabon is reduced by 26% and 24% respectively, where the oil feedstock is assumed to be a waste product. POX remains 46-59% higher cost than the SMR incumbent. The feedstock costs for Naphtha remains high in Angola, resulting in the LCOH remaining unchanged from the base case in 2020, this cost factor and long-distance pipeline requirements for offshore CO_2 T&S makes Angola the costliest scenario.

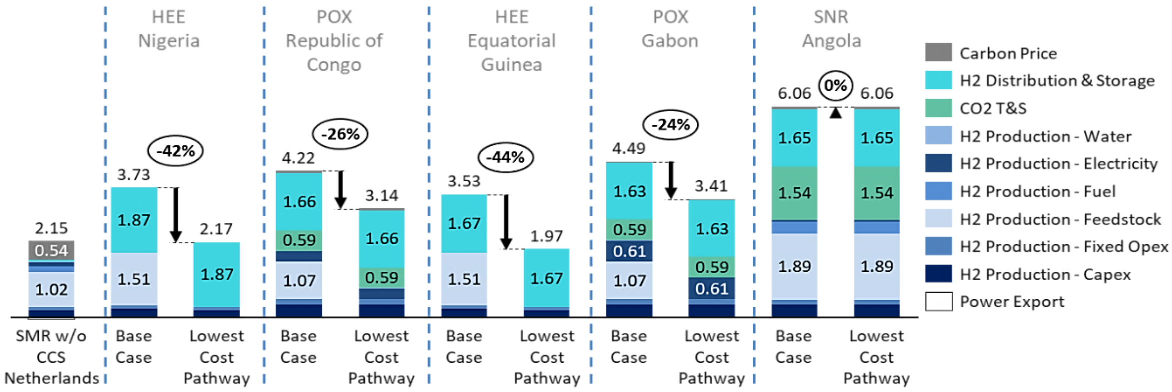

Figure 5. LCOH (€/kgH_2) comparison for base case and lowest cost pathway scenarios in the West Africa in 2020

The LCOH in the West Africa base case and lowest cost pathway in 2050 are provided in Figure 6. The LCOH ranges from 2% lower to 46% higher than the SMR incumbent in the base case. HEE in Equatorial Guinea was observed to be the lowest cost option in the base case scenario, whilst SNR in Angola is the highest cost option. The hydrogen distribution cost component remains high for all countries. It is assumed that all hydrogen is consumed domestically and therefore distributed to local users via pipeline in the lowest cost pathway scenario in 2050. HEE in Nigeria and Equatorial Guinea have a LCOH of only 0.26 €/kgH_2 and 0.25 €/kgH_2 respectively, whereas POX in the Republic of Congo and Gabon are 1.03 €/kgH_2 and 1.33 €/kgH_2 respectively. The high cost of naphtha feedstock makes SNR in Angola the costliest option.

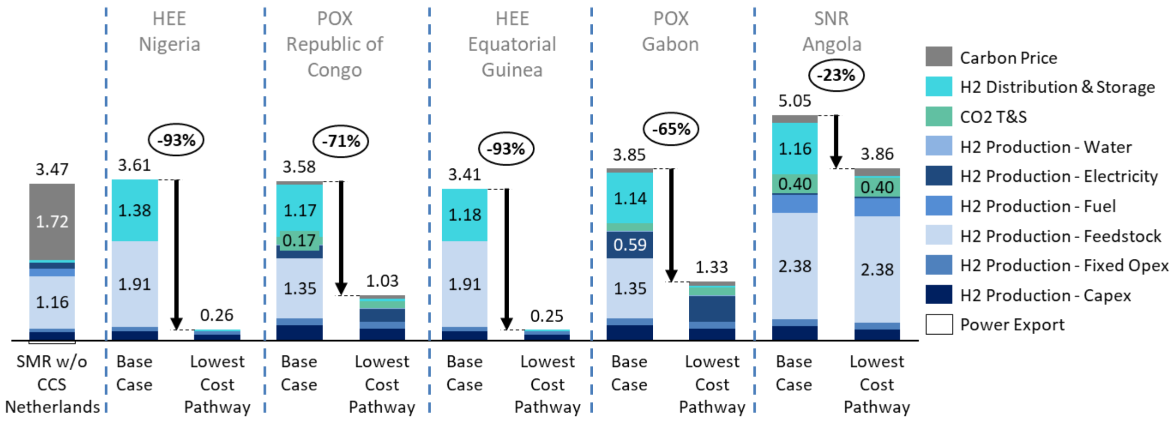

Figure 6. LCOH (€/kgH_2) comparison for base case and lowest cost pathway scenarios in the West Africa in 2050

North Africa, Latin America, and the North Sea:

The LCOH in North Africa, Latin America, and the North Sea base cases, and lowest cost pathways in 2020, are presented in Figure 7. The LCOH ranges from 60-172% higher than the SMR incumbent in the base case. High CO_2 T&S costs components are observed for scenarios in Algeria and Brazil where large onshore and offshore pipeline distances are required respectively. In all cases other than the Netherlands, hydrogen distribution costs are high due to the large distances involved in shipping hydrogen to European and North American markets. SNR in the Netherlands is expensive due to the high cost of naphtha in the region. In the lowest cost pathway scenario, HEE in Venezuela is the only country to have a lower LCOH than the SMR incumbent, with a LCOH reduction of 13%. This is primarily due to the assumption that oil from a depleted reservoir is zero cost and existing infrastructure can be utilised. The LCOH for POX in Algeria and Brazil is reduced by 29% and 19% respectively, where the oil feedstock is assumed to be a waste product. However, all SNR and POX technologies remain significantly higher cost than the SMR incumbent for the regions analysed.

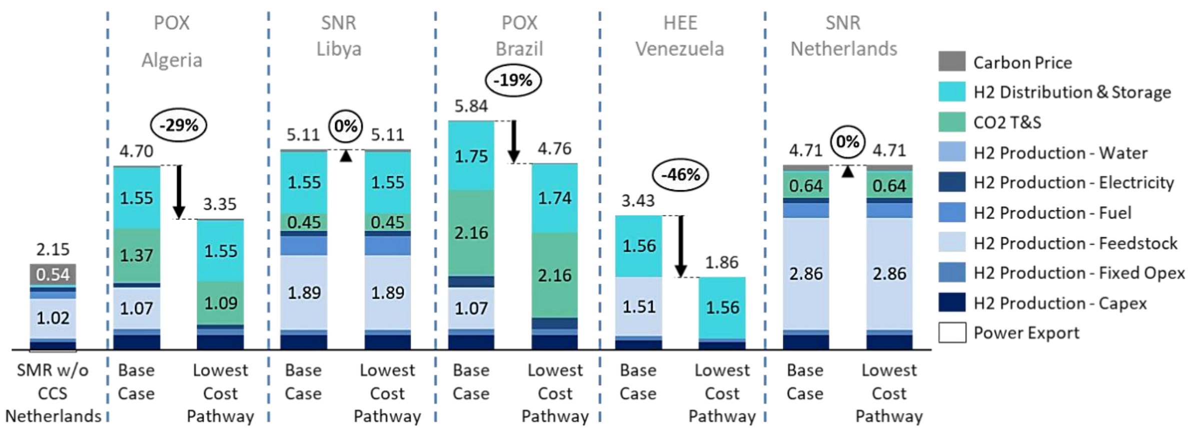

Figure 7. LCOH (€/kgH_2) comparison for base case and lowest cost pathway scenarios in North Africa, Latin America, and the North Sea in 2020

The LCOH in the North Africa, Latin America and North Sea for base case and lowest cost pathways in 2050 are provided in Figure 8. The LCOH ranges from 5% cheaper to 54% greater than the SMR incumbent in the base case. The hydrogen distribution cost component remains high for shipping over long distances to European and North American markets in all cases other than SNR in the Netherlands. The lowest cost option in the base case scenario remains HEE in Venezuela, whilst SNR in the Netherlands is the highest cost option even though hydrogen is distributed locally due to the high cost of naphtha feedstock in the Netherlands. In the lowest cost pathway scenario in 2050, all hydrogen is assumed to be consumed domestically and therefore distributed to local users via pipeline. When combined with other favourable sensitivities, this results in a very low-cost pathway for hydrogen production for HEE in Venezuela at a LCOH of 0.26 €/kgH_2. POX in Algeria and Brazil can be produced at LCOH of 1.12 €/kgH_2 and 1.43 €/kgH_2, respectively when oil feedstock is assumed to be a waste product.

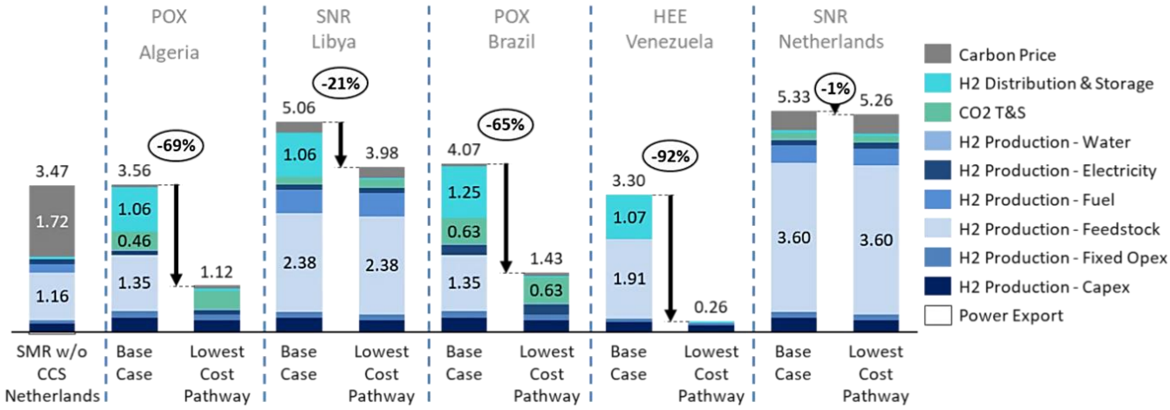

Figure 8. LCOH (€/kgH_2) comparison for base case and lowest cost pathway scenarios in North Africa, Latin America, and the North Sea in 2050

Technology Based Analysis

SNR: 2020 and 2050

The base case SNR technology (see Figure 9) is also the lowest cost pathway. In the case of Angola, Libya and Iraq, the cost of feedstock is the same resulting in similar Gateway 1 (hydrogen production) costs. The UAE has the potential to access naphtha feedstock cheaper than natural gas in the Netherlands, resulting in Gateway 1 costs only 0.10 €/kgH_2 greater than the SMR incumbent. Hydrogen shipping is a high-cost component for all regions other than the Netherlands due to the large distances involved. The greatest cost variations come from the CO_2 T&S component. For all regions, CO_2 pipelines will require development with onshore pipelines considered in the UAE, Libya and Iraq, and offshore pipelines considered in the Netherlands and Angola. Short distance onshore CO_2 pipelines in Iraq result in the lowest CO_2 T&S costs. Whereas Angola has the highest cost due to the large offshore pipeline distances that could be required to connect to potential offshore storage sites.

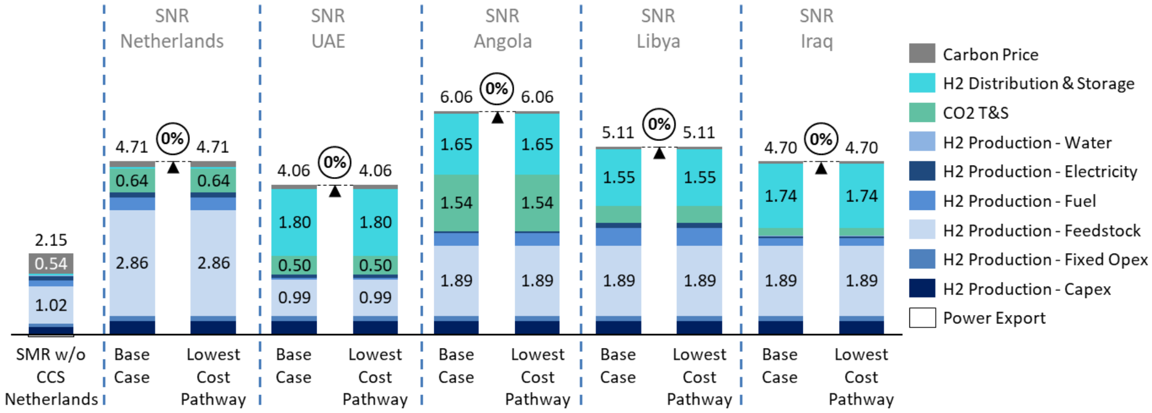

Figure 9: LCOH (€/kgH_2) comparison for SNR base case and lowest cost pathway scenarios in 2020

The LCOH in the SNR base case and lowest cost pathways in 2050 are presented in Figure 10. In both the base case and the lowest cost pathway, the UAE has access to the lowest cost Naphtha feedstock, whilst the Netherlands is the most expensive. In all cases, the cost of CO_2 T&S is significantly reduced in 2050 with a 74% reduction in the case of Angola. The cost of hydrogen distribution remains high for all cases where shipping is considered, whilst distribution to local users results in a significant cost saving in the lowest cost pathway. For all regions, cost reductions at Gateway 1 are the most crucial for ensuring future competitiveness and therefore the utilisation of low-cost feedstock and fuel should be prioritised.

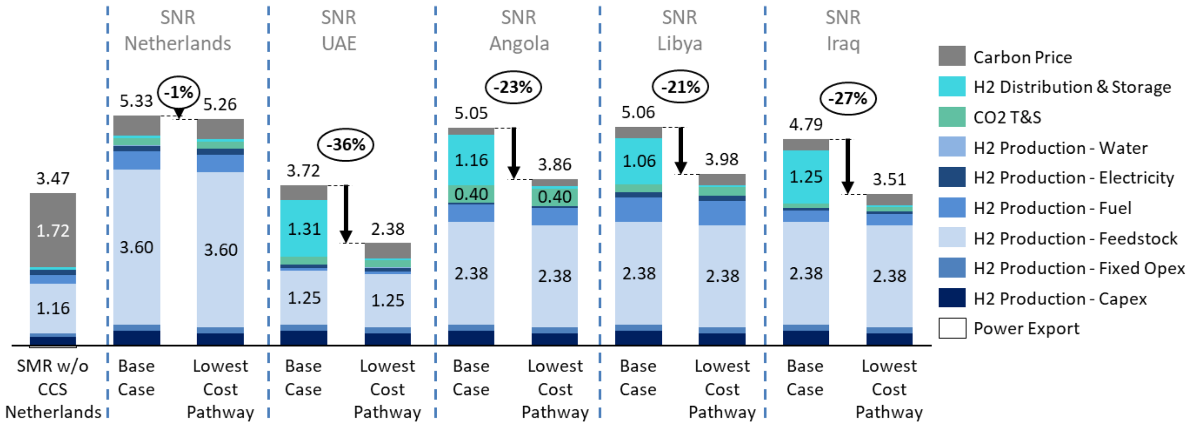

Figure 10: LCOH (€/kgH_2) comparison for SNR base case and lowest cost pathway scenarios in 2050

POX: 2020 and 2050

The LCOH in the POX base case and lowest cost pathways in 2050 are presented in Figure 11. For all cases considered, the cost of oil feedstock is the same with variations in the Gateway 1 costs emanating from differences in the costs of local electricity. In Kuwait, it is possible to access very low-cost industrial electricity, whereas higher electricity prices in Gabon, make this cost component more significant. For all cases considered, hydrogen distribution costs remain high due to shipping over large distances to European, North American, and Asian markets. For all regions, the greatest variation comes from the CO_2 T&S costs. Kuwait has potential to develop relatively short distance onshore pipelines resulting in low costs, whereas Brazil is likely to require long distance offshore pipelines to access local geological storage that are significantly more expensive to develop.

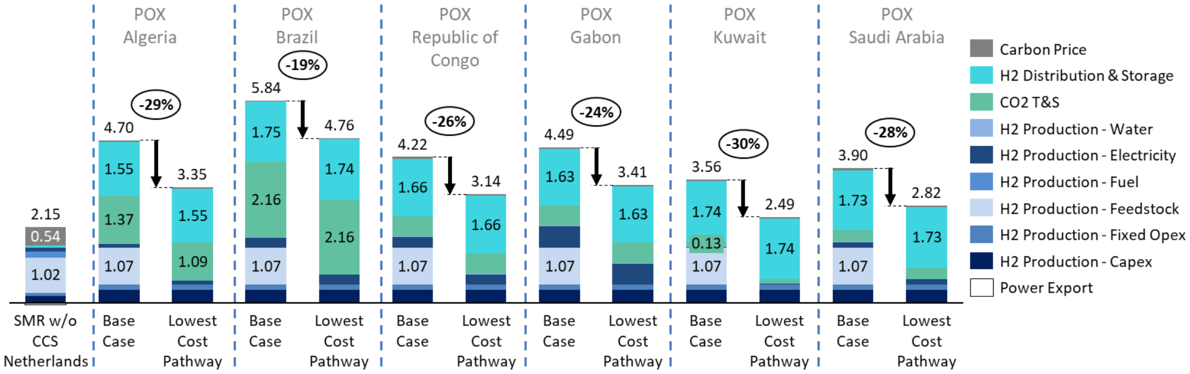

Figure 11: LCOH (€/kgH_2) comparison for POX base case and lowest cost pathway scenarios in 2020

The LCOH in the POX base case and lowest cost pathways in 2050 are provided in Figure 12. In a similar manner to 2020, the cost of oil feedstock is the same for all regions and variations in the Gateway 1 cost come from the local price of electricity. Where large distance CO_2 pipelines are required in Algeria and Brazil, the CO_2 T&S component is reduced by 66% and 71% in the base case respectively. This is due to increased hydrogen production resulting in increased CO_2 pipeline utilisation and technical learnings reducing costs due to increased levels of deployment. Very low-cost POX hydrogen production can therefore be achieved in regions with access to waste oil feedstock, low-cost CO_2 T&S and cheap local electricity.

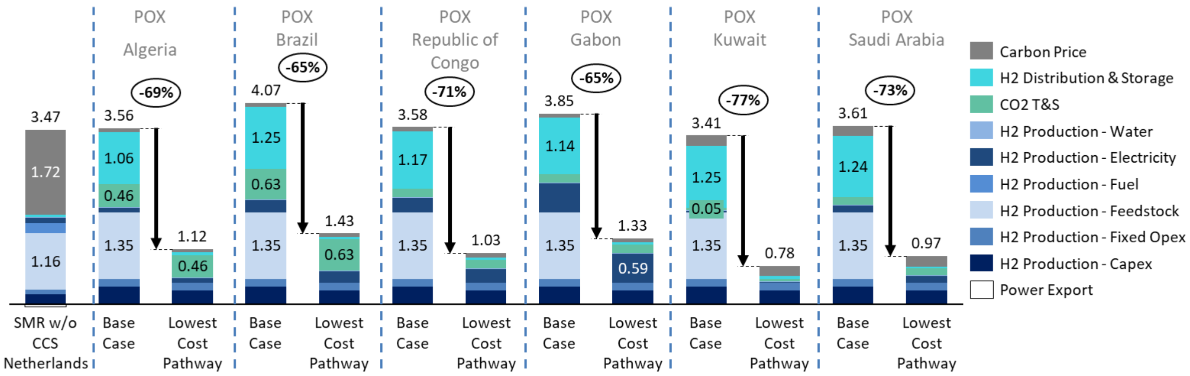

Figure 12: LCOH (€/kgH_2) comparison for POX base case and lowest cost pathway scenarios in 2050

HEE: 2020 and 2050

The LCOH in the HEE base case and lowest cost pathways in 2020 are provided in Figure 13. For all cases considered, the cost of oil feedstock is the same resulting in identical Gateway 1 costs. Variations in the LCOH come from differences in shipping distances; however, the hydrogen distribution component only varies by 0.31 €/kgH_2 across all regions. The lowest cost pathway shows that HEE can be cost competitive with the incumbent SMR technology in all regions when oil from depleted reservoirs can be accessed at zero cost.

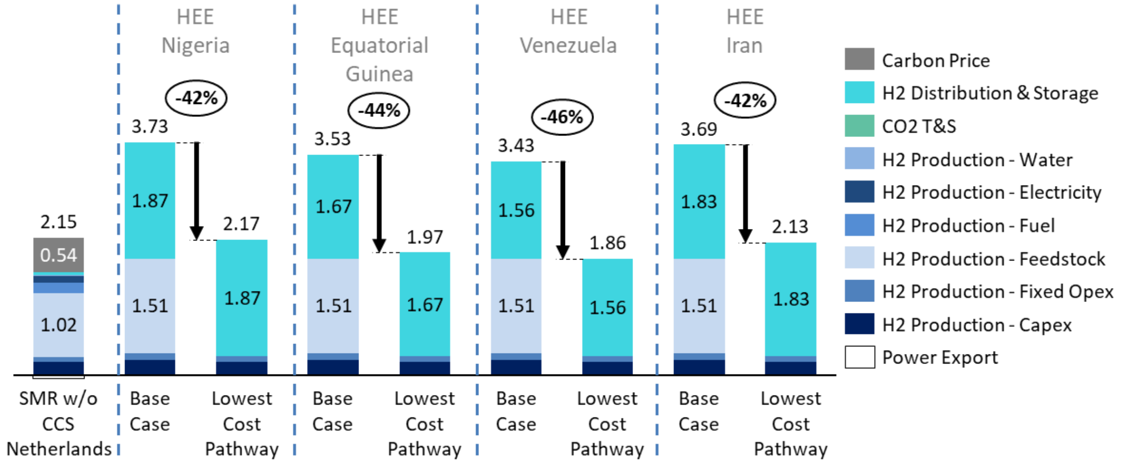

Figure 13: LCOH (€/kgH_2) comparison for HEE base case and lowest cost pathway scenarios in 2020

The LCOH in the HEE base case and lowest cost pathways in 2050 are provided in Figure 14. In a similar manner to 2020, the cost of oil feedstock is the same for all regions and variations in the LCOH come from variations in the hydrogen distributions costs. In the lowest cost pathway where it is assumed that hydrogen is distributed to local markets via pipeline and oil from depleted reservoirs can be accessed at zero cost, HEE has the potential to supply hydrogen at very low prices. Cost reductions of up to 93% in comparison to the SMR case in the Netherlands could be achieved resulting in the lowest overall cost of all the technologies analysed in this study. However, it should be noted that HEE is currently at TRL 4-6 and is yet to be deployed at scale, thus exposing the technology to a high degree of uncertainty at this stage in time.

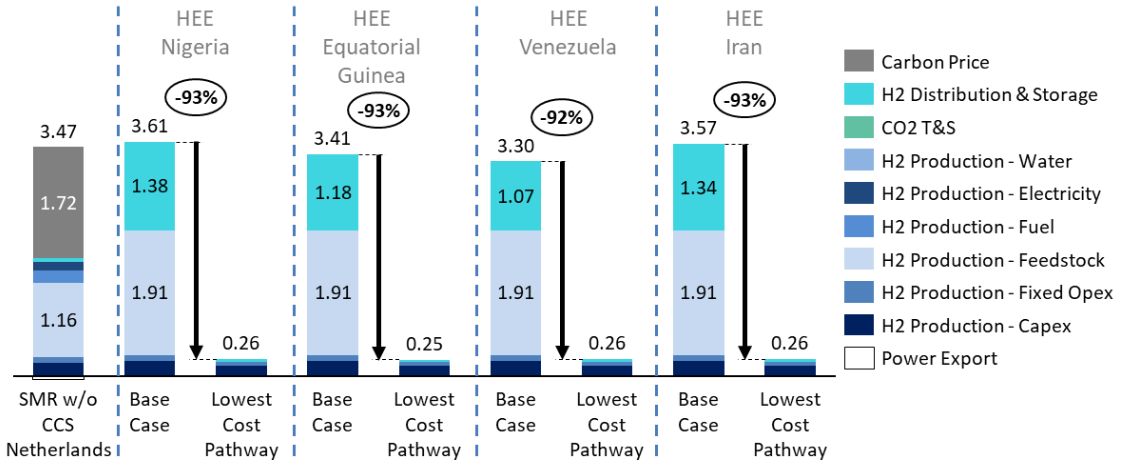

Figure 14: LCOH (€/kgH_2) comparison for HEE base case and lowest cost pathway scenarios in 2050

Environmental analysis

The carbon footprints of each of the studied oil and oil-based blue hydrogen production scenarios are presented in Figure 15. All the blue hydrogen technologies were observed to produce hydrogen with significantly lower carbon footprint than the grey hydrogen benchmark by about 47 to 87% in 2020. The CO_2 produced from the benchmark SMR accounts for the largest share of the carbon footprint due to mainly burning of natural gas as fuel to heat the process and the process emissions. The net electricity of the benchmark technology is 0 kWh/kg H_2.

SNR can achieve a carbon footprint reduction between 58% to 67% compared to the benchmark. Naphtha and direct CO_2-emissions account for the largest contribution to the carbon footprint. The carbon footprint of SNR was observed to slightly vary between countries due to the limited amount of electricity required for the process. Direct CO_2 emissions accounts for a notable carbon footprint of SNR in this study because the CO_2 capture efficiency is modelled at 90%.

POX can achieve a carbon footprint reduction between 47% to 77% compared to the benchmark technology. The largest carbon footprint in POX was mainly due to the electricity source and the use of vacuum residue. Unlike, SNR, this technology was observed to be significantly impacted by regional differences due to the requirement for a large amount of electricity. For this reason, the carbon footprint of Saudi Arabia, which is reliant on fossil-fuel for electricity generation, is high, thus, this scenario has the highest carbon footprint out of the different scenarios studied. However, in light of the Saudi green initiative to meet 50% of the Kingdom's domestic energy needs from renewables by 2030, the carbon footprint of POX in Saudi Arabia is set to significantly reduce.[4] In contrast POX in Brazil delivers the second lowest carbon footprint, mainly due to utilisation of Brazil's domestic electricity, which is 80% hydropower.

HEE can achieve a carbon footprint reduction of between 71% to 78% compared to the benchmark technology. This technology can potentially produce hydrogen with a very low carbon footprint because the oil required is reformed in situ. Hydrogen is separated via a membrane and all carbon containing compounds remains in the reservoir. Therefore, direct emission is not associated with HEE, consequently, no CO_2 is required to be captured and transported to a storage location outside of the production facility. However, HEE requires electricity for oxygen generation and hydrogen compression, which can be sourced from the grid or using the produced hydrogen.

[4] Saudi Green Initiative. Reducing emissions. 2021

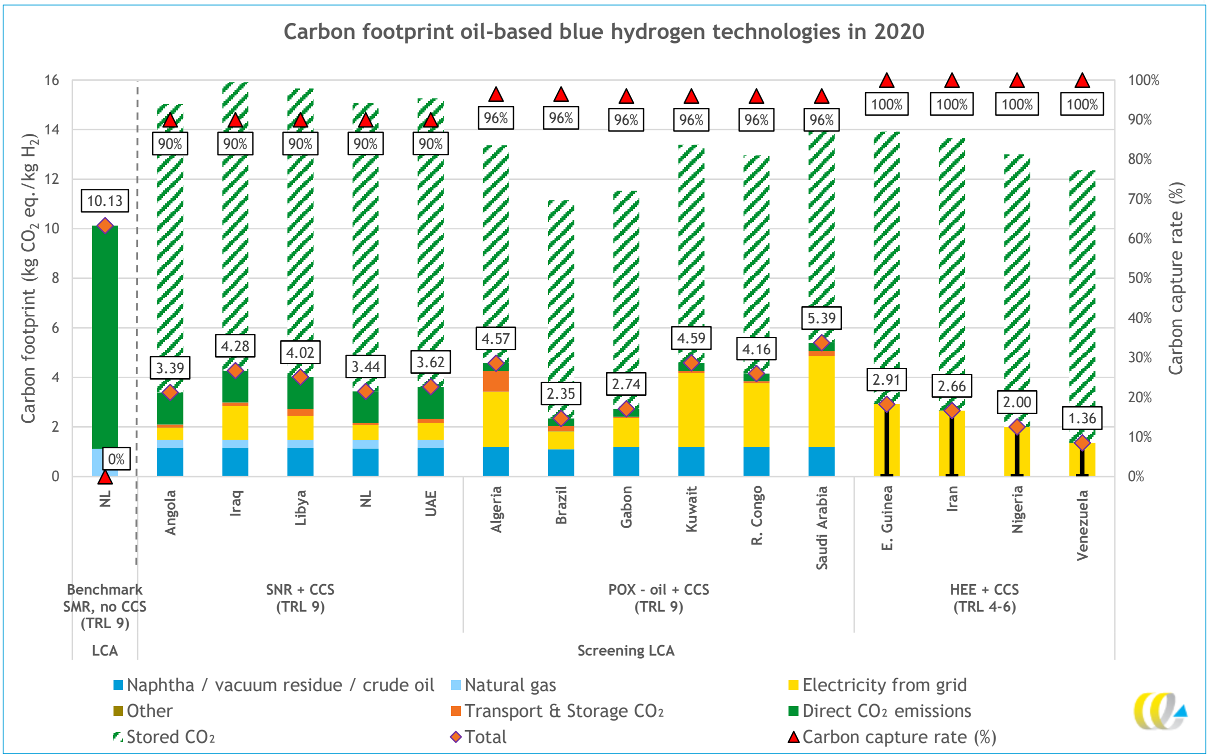

Figure 15: Analysis of the carbon footprint of oil and oil-based blue hydrogen production scenarios against the grey hydrogen benchmark

Key sensitivity parameters were changed to assess the overall impact on the carbon footprint of the studied technologies in 2030 as follows.

- Sensitivity Analysis 1: For all technologies (including the benchmark), the electricity mix has been adjusted to the country specific expected mix in 2030.
- Sensitivity Analysis 2: The carbon capture rate of steam naphtha reforming is increased from 90% to 99%.
- Sensitivity Analysis 3: Local vs shipping CO_2 T&S scenarios are analysed for Angola, Algeria, and Kuwait.

Presented in Figure 16 is the analysis of the carbon footprint of oil and oil-based blue hydrogen production scenarios with estimated country specific carbon footprint of electricity in 2030. The carbon footprint of the blue hydrogen technologies further reduces by 51% to 90% against the benchmark due the reduction of the carbon footprint of the electricity mix in sensitivity analysis 1. In sensitivity analysis 2, the CO_2 capture rate has a significant impact on the carbon footprint, the carbon footprint in the Netherlands was reduced from 66% to 77% when the CO_2 capture rate is increased from 90% to 99%. Sensitivity analysis 3 demonstrated that both transport and distance and modality chosen significantly impacts on the carbon footprint. This sensitivity analysis shows that both transport distance and modality chosen for the captured CO_2 can have a substantial effect on the carbon footprint of a technology and the cost. The preferred transport and storage scenario is different per case, depending on the transport distances. For instance, if the CO_2 is shipped instead of locally stored, the CO_2 T&S impact on the carbon footprint increases from 2% to 10% and 4% to 20% for Kuwait and Angola respectively.

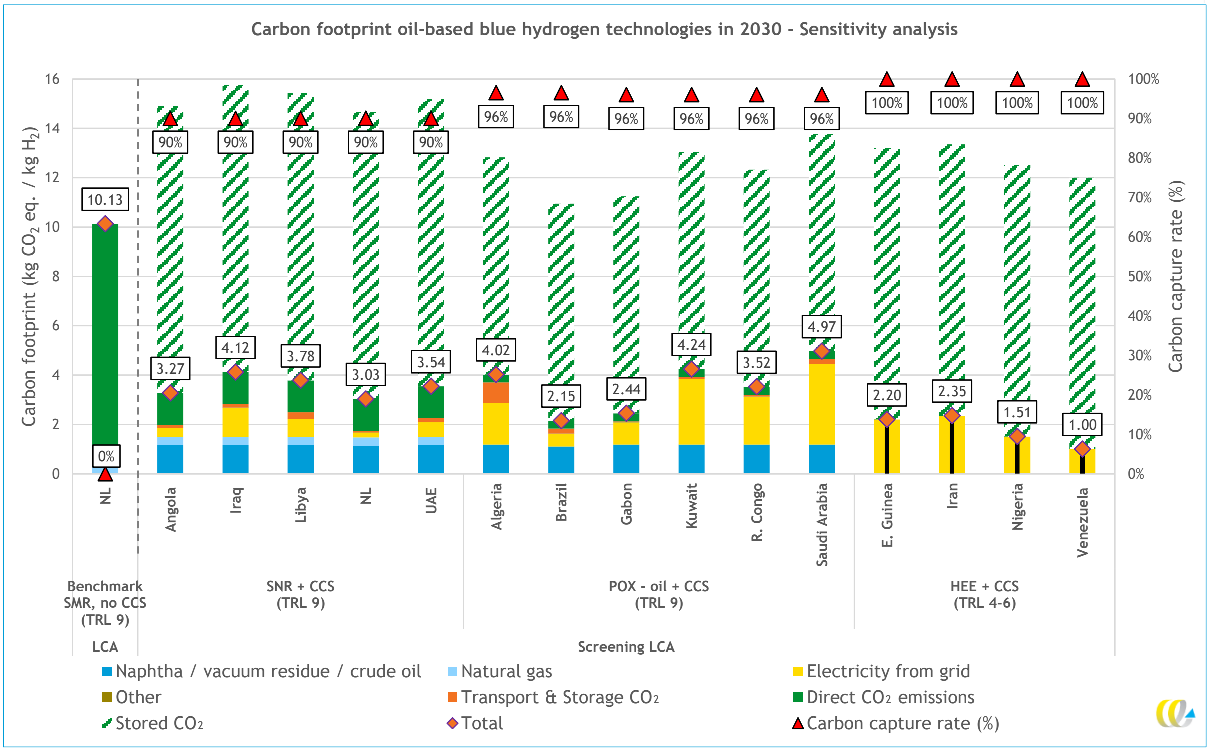

Figure 16: Analysis of the carbon footprint of oil and oil-based blue hydrogen production scenarios with estimated country specific carbon footprint of electricity in 2030

In the parallel study titled 'Global Roadmap to Blue Hydrogen', four different natural-gas hydrogen production technologies in the Netherlands were studied. It is not possible to draw like-for-like comparisons despite the same LCA methodology employed due to variations in regional settings, CO_2 capture efficiencies, purity of hydrogen, assumptions made, and uncertainties encountered. However, it can be deduced from both studies that the carbon footprint is significantly lower than the benchmark technology.

EXPERT REVIEW COMMENTS

Four reviewers from the industry, academia and other organisations took part in the expert review process of this study. Most of the comments were minor and which calls for straightforward responses, clarifications and/or modifications. It is worth noting that all the reviewers had positive reviews of the study in terms of inclusiveness and relevance. Some of the most substantive review comments are as follows:

- A recommendation was put forward to streamline the regional discussions of the case study regions in Chapter 3 and regional case studies in Chapter 4 or produce a well-defined textural linkage between the two chapters. The report structure was thus, appropriately addressed.
- A reviewer also called for renouncing the colour taxonomy for hydrogen used in the study. Instead, a codification based on carbon intensity of hydrogen production technologies was recommended. It is worth noting that at the study's inception, discussions on moving away from colour terminology in favour of the carbon intensity of the process were in their early stages. Since then, the IEA for one has decided to adopt carbon intensity rather than using colour terminology. While IEAGHG will not be dogmatic in conversations relating to hydrogen production, it will favour the use of carbon intensity for future studies.
- Given the low TRL of HEE and the level of confidence that can be placed on techno-economic data. HEE should be treated as a hypothetical exercise and where for examples POX or SNR is challenging to deploy. The low cost and carbon intensities obtained for these technologies

should be presented with this caveat in mind. While SNR and POX are, of course, both mature technologies, it was felt that the introduction of a low-TRL, though promising technology would add interest to the study. There was no intention to suggest the technology was currently on a competitive level with the other two. In fact, the status of the HEE technology is made quite clear, with appropriate caveats included as appropriate. essentially designating it a hypothetical exercise as suggested.

CONCLUSIONS

- This study has demonstrated that there are pathways to competitively produce hydrogen derived from oil and oil-based products when compared to the other mainstream alternatives such as hydrogen derived from natural gas and/or electrolytic hydrogen. The competitive potential of the three studied technologies are as follows:
    - SNR: This technology has the potential to be deployed close to a refinery which supplies Naphtha. SNR cost is, however, 118% higher than SMR in Netherlands because of the high feedstock cost. Therefore, this technology is competitive when cost of naphtha is lower than natural gas.
    - POX: This technology can readily be deployed close to a refinery which can supply a vacuum residue. POX has the advantage of utilising other waste oil products as feedstock, consequently improving its economics.
    - HEE: If this technology is proven, it has the potential for co-production of oil and hydrogen and dedicated hydrogen production from depleted oil reservoirs. Further, HEE has a competitive edge in regions where SNR and/or POX are costly.
- In 2020, all oil-based hydrogen production technologies have a higher cost than both the reference grey hydrogen production case; and natural gas based blue hydrogen production in the Netherlands via steam methane reformation. This is because of high and variable feedstock costs and high hydrogen distribution and CO_2 T&S expenditure.
- For the 'lowest case' scenarios in 2050 eleven out of the fifteen oil-based hydrogen production technologies, which distribute hydrogen locally, are less expensive than the local consumption of blue hydrogen derived from SMR in the Netherlands (which is exposed to high carbon prices). The influence of larger markets in oil-producing regions, and economies of scale in hydrogen distribution and CO_2 T&S, reduces the cost of the oil-based hydrogen production in 2050.
- The findings of this study shows that in the short term, blue hydrogen from oil-based feedstocks produced in the Middle East, and exported to East Asia and Western Europe, is likely to be produced at lower cost than from green hydrogen production. The significant range in export costs for all three studied blue hydrogen technologies is a result of the varying feedstock costs in each country. However, beyond 2030, the falling cost of renewables is envisioned to make green hydrogen production increasingly competitive and lower cost than blue hydrogen production in cases where low-cost renewable electricity is available.
- The LCA for the blue oil-based hydrogen production technologies shows that the carbon footprint for all analysed technologies is significantly lower than the reference grey hydrogen production case with a reduction of the carbon footprint ranging between 47-87%. The same technology was established to exhibit different environmental impacts based on regional differences in the carbon footprint of the electricity, feedstock, and fuel. Despite employing high CO_2 capture rates, the carbon footprint of the electricity production was found to have a large impact on the environmental impact of POX and HEE.
- The CO_2 T&S is a significant cost component for POX and SNR hydrogen production technologies in this study. Therefore, reducing costs in this area will be crucial to ensuring cost competitiveness with established grey hydrogen production. The development of shared CCS

infrastructure in industrial clusters to take advantage of economies of scale will ensure CO_2 T&S costs are reduced.

- The carbon capture rate has significant effect on the carbon footprint of blue hydrogen production technologies. A higher carbon capture rate decreases the carbon footprint significantly, even if the electricity requirements increase by 10%. Thus, the conclusion that changing the carbon capture rate has a significant effect on the overall carbon footprint is relevant for all blue hydrogen technologies.
- Production of blue hydrogen via technologies that use oil and oil-based feedstocks has yet to be demonstrated at scale. The successful deployment of these technologies relies on a multiplicity of factors such as: proving technical and financial viability; validating CO_2 footprint through real-world measurement; and assessing integration with the wider regional supply chains.
- Prime levers to unlock the blue hydrogen economy must be met. This includes creating demand via incentivizing decarbonization through low carbon hydrogen, especially in the hard to abate sectors, ensuring access via making low carbon hydrogen accessible through the infrastructure, and lower cost via creating economies of scale to reduce cost and open new markets. This is the first stage towards long-term low-cost blue hydrogen production.

RECOMMENDATIONS

- Further work is needed to demonstrate and optimise blue hydrogen projects at scale based on oil and oil-based feedstocks. The data generated from these demonstration studies is envisaged to close knowledge gaps and support the development of large-scale oil-based hydrogen production technologies in oil rich regions.
- Studies to determine and characterise oil and oil-based feedstocks for each technology and assessment of the degree of flexible operation i.e., a particular technology accommodating different oil-based feedstocks for hydrogen production is required to inform and facilitate blue hydrogen development.
- Process data availability is key to assessing the TEA (techno-economic assessment) and LCA (life-cycle analysis) of emerging and promising hydrogen production technologies based on oil feedstocks. Therefore, continued R&D, investor funding and favourable government policies is called for to stimulate such research endeavours and unlock the potential of these technologies.
- Assessment of the local hydrogen demand landscape and exploring the means to reduce cost in the value chain for lower cost hydrogen distribution, is essential. Leveraging learnings and investments from ongoing projects on the reuse of existing infrastructure for CO_2 T&S is expected to stimulate the development of blue hydrogen from oil-based feedstock.
- Assessment of the significance and implication of oil and oil-based feedstocks for blue hydrogen production, especially as oil production and utilisation is likely to decline in a net zero emissions (NZE) economy, is required. This appraisal could further explore pathways where low value oil products like waste oil and exhausted oil wells can be accessed.
- Sharing of expertise and collaboration between academia, technology developers and the investors is essential to make information readily accessible to enable accelerate progress.

Blue Hydrogen
Beyond the Plant Gate

A report for

ieaghg

Element Energy & CE Delft

August 2022

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To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

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This study was developed in parallel with '**Low-Carbon Hydrogen from Natural Gas: Global Roadmap**", which studies the production of blue hydrogen from natural gas. Many readers may find it useful to read the studies together to provide complementary information and perspectives.

Executive Summary

Hydrogen is increasingly recognised by public and private sector stakeholders around the world as a key element in meeting the Paris Agreement's goal. To ensure decarbonisation, hydrogen (H_2) must be produced in a low carbon way. Hydrogen derived from fossil fuels with carbon capture and storage (CCS), called blue hydrogen, represents a viable generation pathway with large-scale, serving as a vector for achieving climate goals.

Traditionally, the main hydrogen production technology has been steam methane reforming (SMR) without CCS, also known as grey hydrogen. SMR has been the subject of most blue hydrogen assessment studies to date, including IEAGHG's 2017 'Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS'. However, new hydrogen production technologies are emerging and are considered for deployment by recent project developers.

The purpose of this study is to enrich knowledge and compare the deployment of hydrogen produced from oil and oil-based feedstocks with incumbent natural gas-based technologies in regions with significant potential for oil-based blue hydrogen production. The findings of this study will be of interest to policy makers, industrial emitters exploring fuel switching opportunities, oil-producing regions looking to transition to net zero and technology developers.

Oil-Based Hydrogen Production

There are a range of hydrogen production technologies at different stages of commercial maturity. This study focuses on the blue hydrogen technologies which use oil or oil-based products as a feedstock. Their competitiveness with other blue (such as auto thermal reforming) and green (electrolysis) hydrogen production technologies will depend on respective techno-economics. This includes technological maturity, access to low-cost feedstock, and government policy, i.e., the European Union has set a target of 40GW installed electrolyser capacity by 2030[1], whereas the UK has targeted 5GW of low carbon capacity (including blue hydrogen) by 2030[2].

In the near-to-medium term, however, blue hydrogen from oil could provide a significant fraction of the world's low carbon hydrogen due to the ability to deploy these facilities at large scale in industrial clusters with CCS. This also satisfies industrial demand which is responsible for nearly all current demand. The blue hydrogen production pathways which use oil-based feedstocks selected for detailed analysis in this study are described below.

Steam Naphtha Reforming (SNR)

Steam reforming production accepts shorter-chain hydrocarbons in the range of natural gas to naphtha. These plants are typically sized between 35 & 700MW and facilities utilising natural gas feedstock are responsible for nearly 50% of the world's hydrogen production[3]. Naphtha can be used as an alternative feedstock to natural gas in the steam reforming process and is analysed as the oil-based feedstock in this study. The steam reforming of naphtha feedstock produces a syngas stream which is then fed through the WGS in a similar manner to the partial oxidation process. Catalytic reactions between carbon monoxide (CO) and steam in the WGS reactor facilitate the production of additional hydrogen.

Partial Oxidation (POX)

Gasification (for solids) and partial oxidation (POX – for liquids and gases) is widely deployed at a global scale for hydrogen production and is particularly prevalent in countries where coal is both more widely available and at lower cost than natural gas[4]. This is commonly the case in East Asia. The process involves gasification of feedstock material such as heavy oil fractions (although coal and natural gas can also be utilised), at very high temperatures (1,300 – 1,500 °C) in the presence of oxygen and steam to produce a mix of hydrogen, carbon

[1] IEA 2021, Global Hydrogen Review 2021
[2] GOV UK 2021, UK Hydrogen Strategy
[3] Kalamaras & Efstathiou 2013, Hydrogen Production Technologies: Current State and Future Developments
[4] IEA 2019, The Future of Hydrogen

dioxide and carbon monoxide known as syngas[5]. The syngas stream is then fed through the Water Gas Shift (WGS) reactor where catalytic reactions between carbon monoxide and steam facilitate the production of additional hydrogen.

Hygienic Earth Energy

Hygienic Earth Energy (HEE) is a process patented by Proton Technologies, a Canadian based company that has developed a method of producing large quantities of blue hydrogen from oil-based feedstocks. HEE utilises established technologies for hydrogen production from the oil and gas industry, deploying them in an innovative configuration. The process involves the combination of heating hydrocarbon reservoirs by injecting high purity oxygen deep into the reservoir, whilst harvesting pure hydrogen through a selective membrane. The membrane ensures all other gases are confined below, resulting in pure hydrogen with zero emissions. Whilst this technology shows promise, it has a low TRL of 4 and therefore demonstrations are required to validate its technoeconomics. The inclusion of HEE in this report is illustrative of the author's current understanding of the technology but should not be directly compared with the opportunities for SNR and POX.

Global Hydrogen Demand Forecast

The global demand for hydrogen could increase fivefold with increasing demand from the industrial sector for fuel switching as well as uptake from the mobility, power and heating sectors according to this study. Analysis in this study highlighted that the total demand for hydrogen could be nearly 2,000Mtoe by 2050, as shown in Figure 1, dominated by the transport and industrial sector. However, this demand is not expected to be spread evenly internationally. The greatest demand for hydrogen will initially come from Europe, North America and Asia Pacific. This is due to their advanced position in developing a hydrogen economy and the increased demand for hydrogen in their respective industry, transport, heat and power sectors.

Asia Pacific is expected to have a demand of nearly 50% of the global hydrogen supply by 2050, led primarily from strong demand in India and China. North America and Europe are expected to be responsible for 18% and 10% respectively by 2050.

By sector, industry (with a focus on the production of ammonia, methanol and glass as well as the direct reduction of iron and refining crude oil) remains the dominant driver for hydrogen demand until 2050 whereby mobility reaches parity of scale. This is reflected in the relative decrease of the proportion of hydrogen demand coming from the industrial sector from 99% in 2020 to 35% by 2050. Growth in the mobility and heat sectors are then responsible for 18% and 36% of global demand respectively by 2050. The remaining demand for power gains some significance by 2050, account for 11% of global supply.

The methodology for these figures is given in the Appendices, Section 9.1.

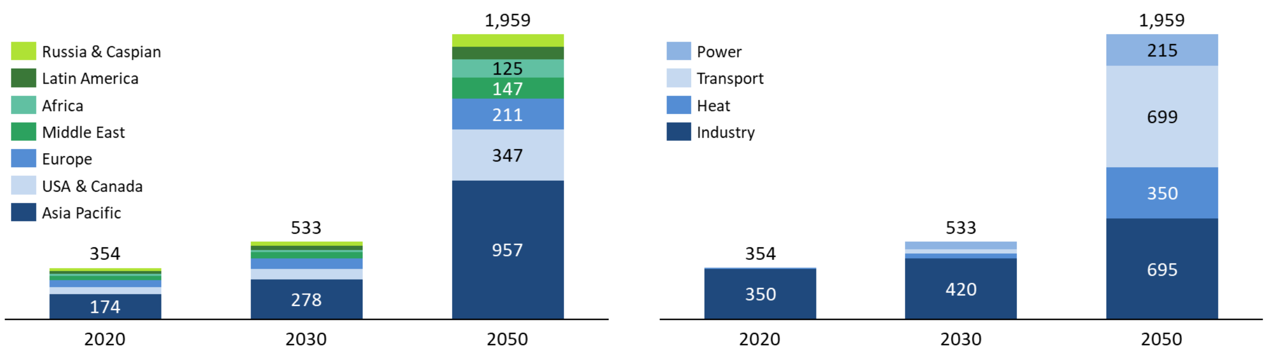

Figure 1: Global hydrogen demand forecast by region (left) and end use case (right) - (Mtoe)

[5] Syngas blend for SMR pre-WGS includes c. 52% H_2, c. 12% CO, 5% CO_2, 29% H_2O and 2% CH_4 on a mole basis. [IEAGHG 2017, Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS]

Techno Economic Assessments (TEA) Comparison

Deployment Potential in the 2020s

In this report, the production of hydrogen from oil and oil-based products is explored in fifteen case study countries; this incorporates the Middle East, West Africa, North Africa, Latin America and North Sea regions. For all regions, a range of oil based blue hydrogen technologies are analysed. The technology choices for each country are not prescriptive and it is likely that many countries would be able to deploy all three oil-based production technologies analysed in this study. For the 'base case' scenarios in 2020 (detailed in Section 5.2) where blue hydrogen is produced and distributed to its nearest major market (explained in the Appendices, Section 9.2.6), all oil-based hydrogen production technologies have a higher cost than both the reference grey hydrogen production case and natural gas based blue hydrogen production in the Netherlands via steam methane reformation (Figure 2). This conclusion is also shared by other green and blue production pathways and, for oil-based blue hydrogen, is due to:

- High and variable feedstock costs which, in all but one case (SNR in the UAE), are greater than the LCOH for SMR without methane
- The high H_2 distribution and CO_2 transport and storage (T&S) costs that arise from the long distances to hydrogen ready markets and CCS projects still in their development stages, respectively.

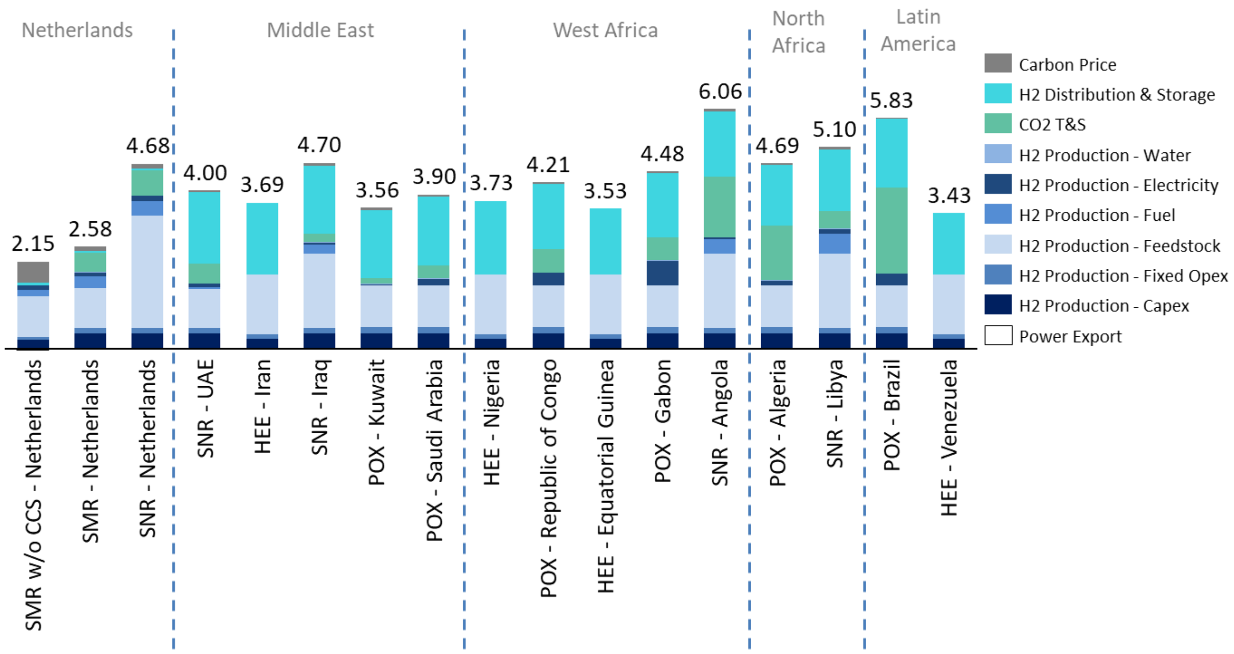

Figure 2: LCOH comparison for base case oil based blue hydrogen scenarios in 2020 compared to the base case SMR without CCS in the Netherlands (€/kgH₂)

Deployment Potential in the 2050s

The situation changes significantly in 2050 due to larger markets in oil-producing regions and economies of scale in hydrogen distribution and CO_2 T&S. The lowest cost pathways are displayed in Figure 3. The SMR without CCS incumbent is significantly exposed to high carbon prices and so it becomes more prudent to compare with other blue hydrogen production technologies; SMR with CCS is used here.

For the 'lowest case' scenarios in 2050 ((detailed in Section 9.4.1) this scenario assumes that each cost component has been optimised to provide the lowest LCOH for all oil-based production technologies), eleven out of the fifteen oil-based hydrogen production technologies, which distribute hydrogen locally, are less expensive than the local consumption of blue hydrogen derived from SMR in in the Netherlands.

- SNR in the Angola is still the highest cost out of these options, due to high feedstock and T&S costs.

- Feedstock costs have been minimised for POX and HEE production technologies where waste products are assumed to be utilised and therefore have no economic value. This is not possible for SNR, which relies on naphtha feedstock, a refined oil product.
- For all scenarios, by 2050, it is assumed that there is increased local hydrogen demand as the transition to net zero increases the demand for hydrogen across the globe. This significantly reduces the costs of hydrogen distribution and storage due to shorter distribution distances.
- Carbon pricing in 2050 is also predicted to be a more significant cost component. However, this also becomes a significant cost component for SNR technology which is more sensitive to increasing carbon prices due to the higher emissions produced than the to the POX and HEE processes.

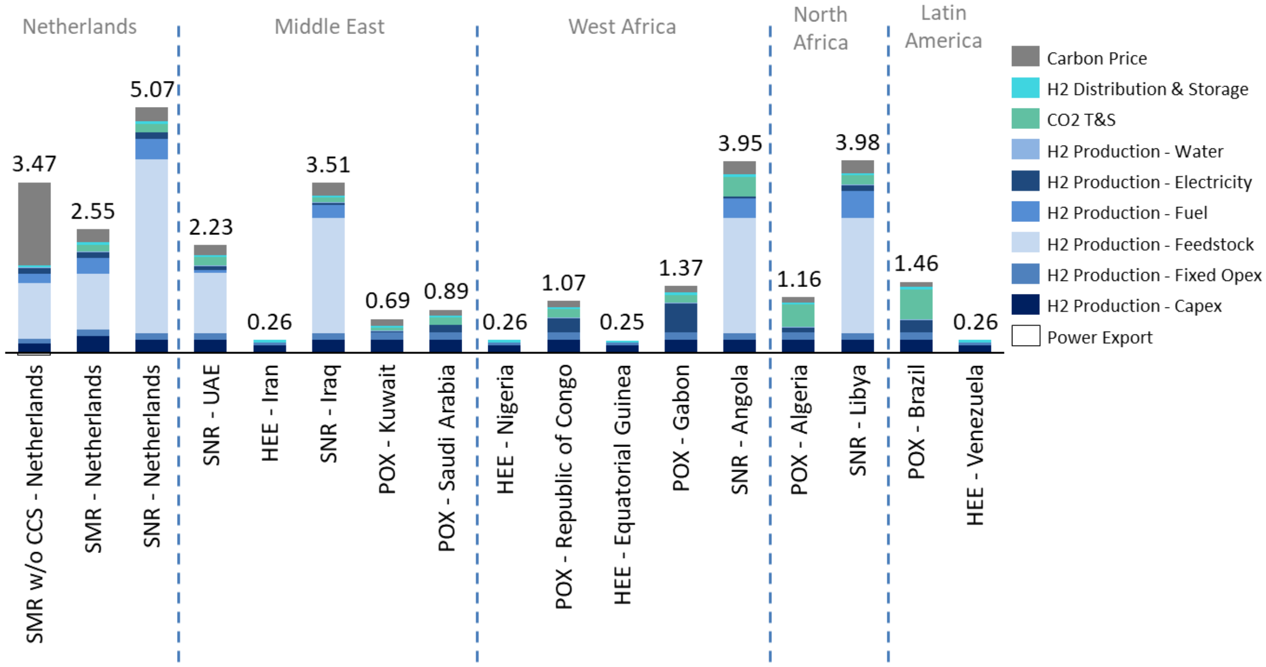

Figure 3: LCOH comparison for lowest cost oil based blue hydrogen scenarios in 2050 compared to the base case SMR without CCS in the Netherlands (€/kgH_2)

Life Cycle Assessment (LCA) comparison

The LCA for the blue oil-based hydrogen production technologies shows that the carbon footprint for all analysed technologies is significantly lower than the reference grey hydrogen production case. Figure 4 shows the LCA for each scenario, with a reduction of the carbon footprint ranging between 47-87%[6].

- The carbon footprint of all technologies is **subject to regional differences**. Even if the same technology is used, differences in the carbon footprint can occur due to regional differences in the carbon footprint of the used feedstock, fuel, and grid electricity.

[6] Using 2020 data, representative of 2020s

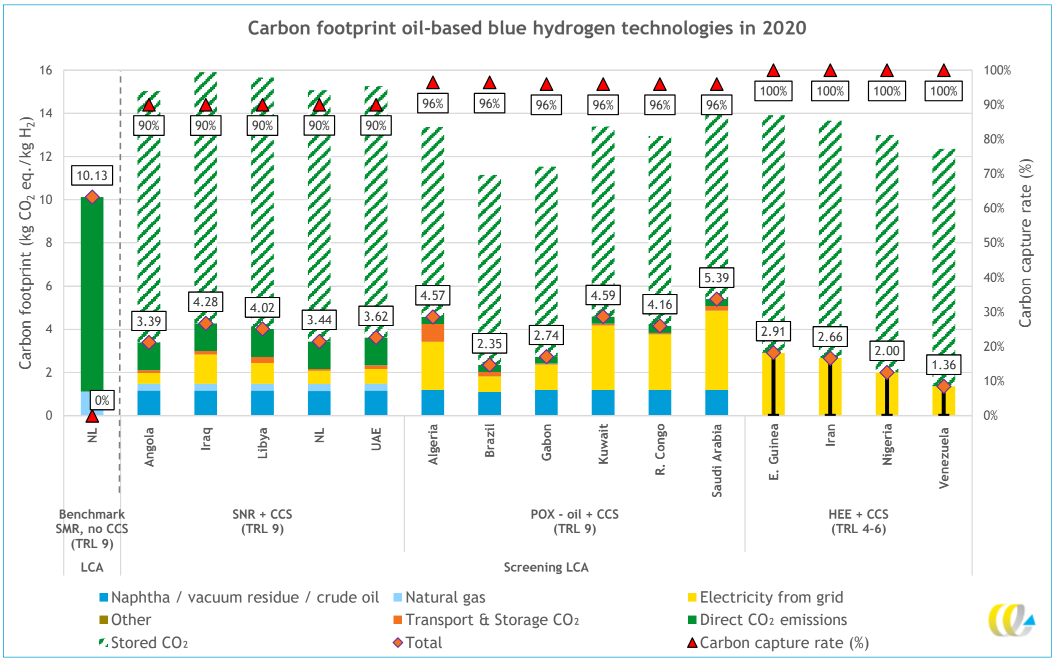

Figure 4: Carbon footprint of oil-based hydrogen production technologies in 2020[7]

- **SMR without CCS (benchmark).** Generated CO_2 emissions account for the largest share of the carbon footprint of grey hydrogen production. These emissions are mostly related to burning of natural gas as a fuel to heat the process and to the process emissions caused by the reaction which takes place.
- **SNR + CCS** can reduce a carbon footprint by 58-67% compared to the benchmark. Naphtha and direct CO_2-emissions account for the largest contribution to the carbon footprint. Compared to the other hydrogen production technologies, the carbon footprint of SNR varies only slightly between countries. This is due to the limited amount of electricity required for the process (of which the carbon footprint varies greatly between countries). As the carbon capture rate of SNR is modelled to be 90% (and so not all CO_2 is captured and stored), the direct CO_2 emissions still account for a large share of the carbon footprint.
- **POX + CCS** can reduce a carbon footprint by 47-77% compared to the benchmark. Electricity and vacuum residue have the largest contribution to the carbon footprint. The carbon footprint of this technology is subject to significant regional differences as it requires a large amount of electricity. This demonstrates that, from an environmental perspective, POX + CCS can be a good option, as long as the carbon footprint of the electricity production is low, whereas if the carbon footprint of electricity production is high, producing hydrogen using a less electricity intensive blue hydrogen technology, such as SNR, is preferable.
- **HEE** can achieve a carbon footprint reduction of 71-78% compared to the benchmark. HEE technology has the potential to produce hydrogen with a very low carbon footprint as the crude oil required for the process are used from within the well in which hydrogen is produced. However, this technology is also the most uncertain, due to its low TRL level of 4-6. The reforming reaction takes place underground and hydrogen is separated using a membrane. Normally, all carbon containing compounds remain in a closed loop within the reservoir. Consequently, there are no direct CO_2 emissions from HEE, nor does CO_2 need to be captured and transported to a storage location outside the production facility. HEE requires electricity for the generation of oxygen and compression of hydrogen. This electricity can be imported from the grid (base case) or generated using the produced hydrogen (alternative). In the base case, electricity is the only source of the carbon footprint associated with hydrogen

[7] 'Other' includes tap water and water treatment. This barely contributes to the carbon footprint and therefore is not visible in the figure. 'Electricity' includes electricity used for H_2 production and compression, electricity generation and O_2 production (POX). The error bar of HEE is explained in Section 6.3.

production. As a result, the carbon footprint depends significantly on the country where the electricity is produced.

- The carbon footprint of the electricity production is a big contributor to the total carbon footprint. This shows that, besides using **CCS** and having a **high carbon capture rate**, a **low carbon electricity source is important** when producing blue hydrogen. As the carbon footprint of electricity production of the investigated countries will likely decrease between 2020 and 2030 (as a result of increased renewable electricity sources), the carbon footprint of the oil-based blue hydrogen technologies will also reduce.

Current Market

Blue hydrogen production technologies utilising oil-based feedstocks will have to compete with established grey hydrogen production technologies in the near-term as well as developing green hydrogen production from renewable sources in the future. SMR without CCS utilising natural gas feedstock is currently the dominant production technology globally and is expected to remain lower cost in the short to mid-term until carbon prices increase. This, of course, is not the only pressure on transition to low carbon alternatives as direct competition with green production is increasingly common. Blue hydrogen production is predicted to remain cheaper than green hydrogen production in the near term.

This study shows that in the short term, all of the oil-based blue hydrogen production technologies analysed are likely to be higher cost than established grey hydrogen production without CCS. However, as carbon pricing increases, CCS integration will be crucial for reducing the cost of fossil fuel-based hydrogen production. Policy support is thus required to increase the uptake of blue hydrogen and bridge the time gap, until carbon price increases result in grey hydrogen production being an unattractive economic option.

The CO_2 T&S "fee" is a significant costs component for POX and SNR hydrogen production technologies in this study. Therefore, reducing costs in this area will be crucial to ensuring cost competitiveness with established grey hydrogen production. The development of shared CCS infrastructure in industrial clusters to take advantage of economies of scale will ensure CO_2 T&S costs are reduced. In the long term, blue hydrogen production will be lower cost than grey due to higher carbon prices.

Opportunities for Blue Hydrogen Producing Regions

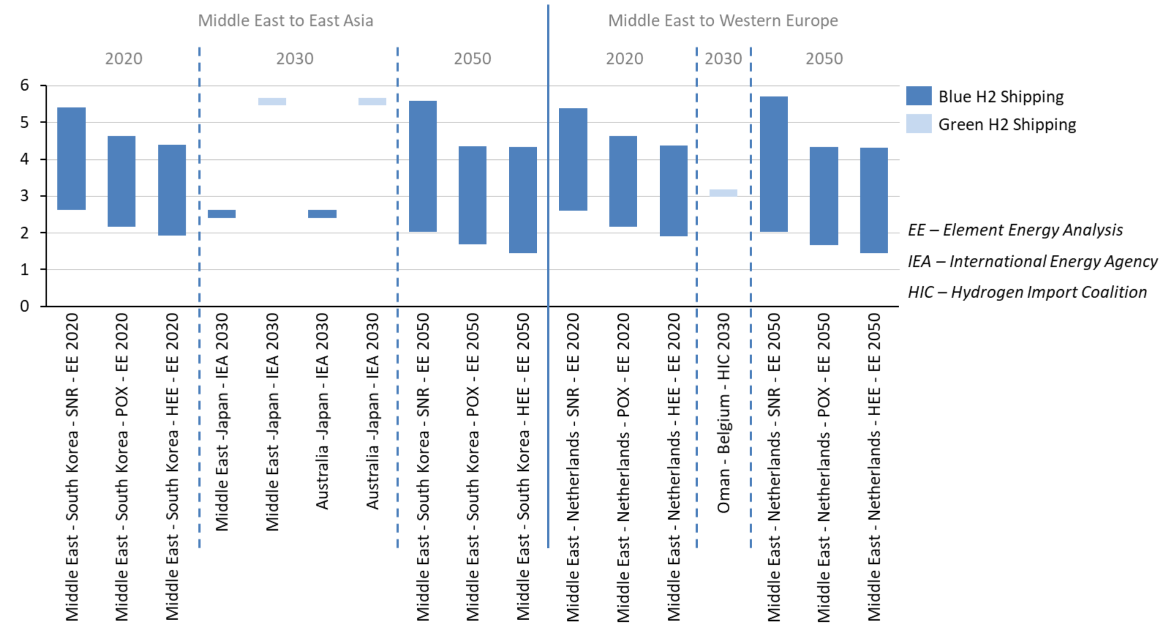

Figure 5: Comparison of hydrogen export costs in the Middle East by type to Asia (left) and Western Europe (right) - (€/kgH$_2$)

Oil-based hydrogen production technologies will have to compete with both natural gas-based blue hydrogen production and green hydrogen production from renewable sources when exporting to developed markets. Predicted costs of green hydrogen exported to Belgium provided by the 'Hydrogen Import Coalition'[8] are compared against both green and blue hydrogen export costs from the IEA's "The Future of Hydrogen"[4] and analysis of oil-based production types done in this study, where the bars show the range of costs in this study. This is displayed in Figure 5 and Figure 6 respectively.

This analysis shows that in the short term, blue hydrogen from oil-based feedstocks produced in the Middle East and exported to East Asia and Western Europe is likely to be lower cost than from green production. The significant range in export costs for all three blue hydrogen technologies is a result of the varying feedstock costs in each country. For SNR, the UAE is likely to be able to access low-cost naphtha feedstock whereas POX and HEE could utilise low-value or waste feedstocks. Blue hydrogen export from the Middle East to Western Europe may be competitive in the short term, however, beyond 2030 green hydrogen production export is predicted to significantly reduce in cost.

Blue hydrogen exports from North Africa to Western Europe are not predicted to be cost competitive in 2020 or 2050 for SNR based technologies. However, POX hydrogen production technology has the potential to be cost competitive in both short- and long-term scenarios at the lower bound of the cost estimate; this assumes that waste or low-value feedstocks would be utilised.

POX based blue hydrogen exports from Latin America to Western Europe are unlikely to be cost competitive in the short term with green hydrogen exports. However, POX hydrogen production has the potential to be cost competitive in the long-term scenario at the lower bound of the cost estimate; this assumes that waste or low-value feedstocks would be utilised. HEE exports from Latin America are predicted to be cost competitive in both short and long-term scenarios. Where depleted oil fields can be accessed at zero or low cost, HEE has the potential to be lower cost than green hydrogen exports.

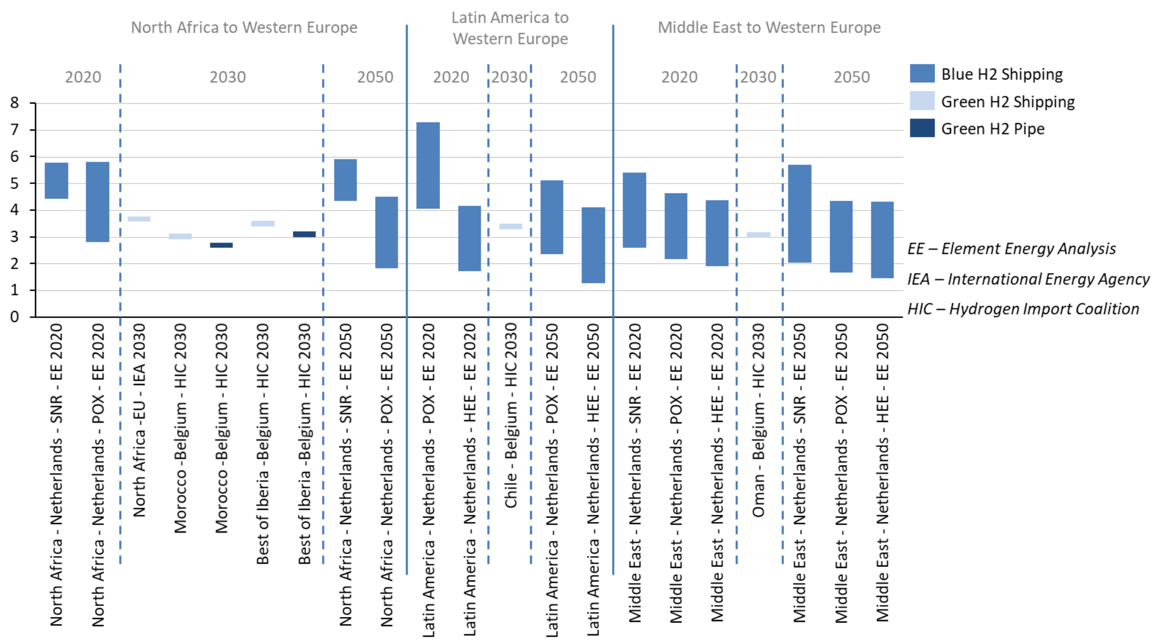

Figure 6: Comparison of hydrogen export costs to European countries by region and production type - (€/kgH_2)

In all cases, upper-bound scenarios (where feedstock costs are significant) are likely to result in the technology being uncompetitive with green hydrogen production methods. There is no comparison with hydrogen exports to North America due to a lack of comparable published data.

[8] Hydrogen Import Coalition 2021, Shipping sun and wind to Belgium is key in climate neutral economy

Future Markets

In the longer term, the falling cost of renewable electricity and alignment with net zero ambitions is likely to make green hydrogen production increasingly competitive and lower cost than blue hydrogen production in cases where low-cost electricity is available. For example, North Africa and Southern Europe are expected to have high capacities of low-cost solar electricity that could be utilised for green hydrogen production via electrolysers. Hydrogen production in developed regions is expected to face significant competition from global hydrogen imports from regions where low-cost hydrogen production is available. This not only includes the import of green hydrogen, but also blue hydrogen production from oil and oil-based feedstocks. If the cost of hydrogen distribution over long distances can be reduced sufficiently, importing low-cost hydrogen may be more economical than local production in regions such as the Netherlands.

Recommendations

Production of blue hydrogen with a minimum CO_2 capture rate of 90% via technologies that use oil and oil-based feedstock has not yet been demonstrated at scale. The successful deployment of these technologies relies on a multiplicity of factors such as: proving technical and financial viability, validating CO_2 footprint through real-world measuring, and assessing integration with the wider regional supply chains. **Government grants**, **risk mitigation measures** and **private industry funding** are essential to drive blue hydrogen demonstration projects forward. This is the first stage towards long-term, unsubsidised low carbon hydrogen production and associated decarbonisation of targeted sectors.

Research, Development and Demonstration

Increased research and development focusing on blue hydrogen production from oil-based feedstocks will be crucial in optimising hydrogen production technologies. Successful demonstration projects will encourage the development of large-scale oil-based production facilities in regions where feedstock supplies are readily available. The uptake of oil-based hydrogen production will be advanced by the following steps:

- **Including blue hydrogen production technologies in CCS cluster plans** to take advantage of scales of deployment. This will reduce CO_2 T&S costs.
- **Further work is needed to explore optimal technology type by region.** This study explored three blue hydrogen production technologies. Technology deployments were considered in 15 countries and cost ranges show that all analysed technologies can be competitive options. Blue hydrogen producers should conduct further feasibility and FEED studies to optimise technology deployment choices.
- **Additional technology development, including demonstration projects, to prove the technologies in the field and raise awareness.** This includes resolving data gaps and uncertainties e.g., Hygienic Earth Energy (HEE) is currently TRL 4 – 6, and process data is therefore less reliable. This will ensure that these technologies are understood and included in national and international hydrogen strategies, facilitating international collaboration.
- **Further evidence gathering around relative economies of hydrogen transportation**. Comparing hydrogen distribution methods at different scales, distances, operating parameters, and archetypes.
- **Exploring local hydrogen demand scenarios and reducing costs in the value chain for lower cost hydrogen distribution**. This includes leveraging learnings and investments from ongoing projects such as Acorn which are demonstrating ways to reuse existing infrastructure for CO_2 T&S.
- **Exploring synergies between transporting CO_2 and hydrogen**. Opportunities to utilise the same port infrastructure and ships for shipping of hydrogen and CO_2.

Policy and Actions

Blue hydrogen production has the potential to produce low carbon hydrogen at large scale. Policy and regulation have a significant role in increasing the uptake of blue hydrogen technologies and discouraging the development of carbon intensive hydrogen production facilities. The following measures will help accelerate this transition:

- Governments should support blue hydrogen technologies with sufficiently low carbon footprints as calculated from life cycle assessments. This includes sufficient high carbon capture rates (preferably >90%), use of electricity with low carbon content, and in case natural gas is used for heat and/or feedstock a strong focus on reduction of methane leakages involved with production and transportation.
- Including blue hydrogen production technologies in CCS cluster plans to take advantage of scales of deployment. This will reduce CO_2 T&S costs.
- Supporting aggressive carbon pricing to outcompete conventional production of “grey” (unabated) hydrogen production technologies.
- Business model development for blue hydrogen production is required to make low carbon hydrogen competitive with that produced from high carbon alternatives.
- International collaboration between global regions with low-cost hydrogen production and those with emerging hydrogen demand. In the short to medium term, materialising these connections may require international trade of hydrogen to areas with more developed hydrogen strategies and with proven end-uses for hydrogen.
- Development of new grey hydrogen production facilities should be discouraged unless they have accompanying CCS retrofit strategies.
- CCS retrofits to existing grey hydrogen production facilities should be encouraged where hydrogen plats are expected to remain operational for many years.

Acronyms and Abbreviations

ADNOC	Abud Dhabi National Oil Company
APU	Auxiliary Power Unit
ATR	Auto Thermal Reforming
ASU	Air Separation Unit
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CFS	Clean Fuel Standard
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DOGF	Depleted Oil and Gas Field
DRI	Direct Reduction of Iron
CNR	Catalytic Naphtha Reforming
EOR	Enhanced Oil Recovery
ESMR	Electric Steam Methane Reforming
EU	European Union
FCEVs	Fuel Cell Electric Vehicles
FEED	Front End Engineering Design
GH_2	Gaseous Hydrogen
GHG	Greenhouse Gas
H_2	Hydrogen
HDVs	Heavy Duty Vehicles
HEE	Hygienic Earth Energy
HHV	High Heating Value
HRS	Hydrogen Refuelling Station
LCA	Life Cycle Assessment
LCFS	Low Carbon Fuels Standard
LCOH	Levelised Cost of Hydrogen
LDVs	Light Duty Vehicles
LH_2	Liquefied Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
LPG	Liquid Petroleum Gas
MEA	Mono-ethanol Amine
N/A	Not Applicable
NH_3	Ammonia
NRMM	Non-Road Machinery
OPEX	Operational Expenditure
POX	Partial Oxidation
PSA	Pressure Swing Adsorption
RED	Renewable Energy Directive
R&D	Research and Development
RPS	Renewable Portfolio Standard
SA	Saline Aquifer
SGP	Shell Gasification Process
SMR	Steam Methane Reforming
SNR	Steam Naphtha Reforming
T&S	Transport and Storage
TEA	Techno Economic Assessments
TRL	Technology Readiness Level
UAE	United Arab Emirates
UK	United Kingdom
UKSAP	UK Storage Appraisal Project
USA	Unites States of America
USD	United States Dollar
VSA	Vacuum Swing Adsorption

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1 Introduction

1.1 Context

Hydrogen is increasingly recognised as one of the key sources of low carbon energy, including for hard-to-abate sector, which could enhance climate mitigation in meeting the Paris Agreement's goal by public and private sector stakeholders around the world. Many governments and other public sector bodies are also committing to support the expanded use of hydrogen and fuel cell technologies, with some seeing a pivotal role for blue hydrogen in the energy transition. The European Commission recently published its hydrogen strategy in 2020 and pledged to support multi-billion investments in the sector with a focus on both green and blue hydrogen[9].

To ensure decarbonisation, hydrogen must be produced in a low carbon way. Low carbon hydrogen can be produced via various routes, including water electrolysis and fossil-fuel routes with carbon capture and storage (CCS). Hydrogen derived from fossil fuels with CCS represents a viable low carbon pathway with large-scale potential in the short and medium-term, serving as a vector for achieving climate goals. The resulting hydrogen can be used as a low carbon energy carrier, with properties similar to natural gas, and is capable of decarbonising multiple sectors, including industry, heating, power generation, and transport. In addition, CCS will play a complementary role in decarbonisation, ensuring that process emissions associated with hydrogen production are safely stored underground.

Hydrogen production from oil and oil-based products has not been fully explored to date. However, hydrogen production from organic feedstocks is a well-established process. Most production routes considered and deployed to date focus primarily on using natural gas, coal, or biomass as the primary feedstock. Coupled with CCS, these pathways could provide blue hydrogen at lower prices than current electrolyser set-ups[1]. However, those feedstocks do not represent the only sources that could be turned into hydrogen. Oil has been used for a long time in fuelling the economy under the form of refined products. The refining process itself consists of a series of chemical reactions which generates, among other chemicals, hydrogen. At the same time, oil-derived chemicals, such as naphtha, could also be a source of hydrogen.

Oil could represent an additional and interesting source of production of hydrogen, bringing potential cost reductions in the blue hydrogen price. Whilst the energy transition would impact oil demand, there is significant infrastructure in place to allow low-cost supply of oil-based feedstocks for hydrogen. At the same time, current oil and gas infrastructure could be repurposed for carbon capture and storage[10], providing an attractive proposition for collocating hydrogen production with carbon dioxide (CO_2) storage, and reducing the costs of blue hydrogen. At the same time, oil products have historically been produced by refineries, with well-established supply chains. Production of hydrogen from oil-based products, such as fractions of the petroleum distillation such as naphtha or residuum, could leverage existing supply chain and lead to significant cost reductions for blue hydrogen.

The scale and potential of oil-derived hydrogen is still unknown. Whilst several technologies are emerging, each considering various feedstocks and production routes, their potential for supplying large volumes of blue hydrogen that the future energy systems need has not been fully explored yet. There is, thus, a gap in understanding whether hydrogen production from oil sources could achieve maturity and could cost-effectively help decarbonise the energy system at a global and regional level. Questions around the infrastructure requirements and distribution channels for hydrogen produced from oil and the associate CO_2 storage are still to be addressed. In addition, the climate benefits of oil-derived hydrogen are still to be determined and compared to other production pathways.

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[9] European Commission 2020, EU Hydrogen Strategy
[10] IEAGHG 2018, Re-Use of Oil and Gas Facilities for CO_2 Transport and Storage

1.2 Objectives and Scope of Work

The primary objective of this study is to provide a comprehensive review of available literature on the current hydrogen landscape and clearly compare the technologies and pathways for producing blue hydrogen from oil and oil-based products, as well as the supply chain implications. The analysis concentrates on the following five objectives:

- To describe existing technologies for producing oil and oil-based hydrogen, their development status, potential for scale up, and integration into the hydrogen and CCS value chain. This includes transportation, distribution and storage infrastructure for the feedstocks used as well as the hydrogen and CO_2 produced.
- To assess the current and future global demand for hydrogen and associated opportunities at a global level for applications in sectors such as transportation, heat, power generation, and industry.
- To conduct a techno-economic and life cycle assessment of different production configurations in several geographic regions, characterised by the availability of oil resources and potential for CCS infrastructure deployment.
- The study will identify key drivers for the deployment of oil-based hydrogen production at scale, discuss the association of different areas with high demand for hydrogen and high production potential, technology maturity, value integration and cost competitiveness with conventional hydrogen production pathways, such as electrolysis and reformation.
- The study should also determine the policy and regulatory gaps required to be closed, including a discussion of potential market mechanisms and business models, market, political and social challenges, and acceptance.

This study has run in parallel to a similar report on production of hydrogen from natural gas[11]. The methodologies for these two reports and associated analyses are, where possible, similar, and so comparisons are made where appropriate.

1.3 Report Structure

The remainder of this report is structured into seven sections and associated Appendices:

- **Section 2** explores blue hydrogen production technologies that use oil and oil-based products as a feedstock. Three technologies are selected from this literature review for techno-economic assessments (TEA) and life cycle assessments (LCA), as described in Section 2.2.
- **Section 3** describes the uptake of hydrogen globally by region and end user up to 2050.
- **Section 4** explores the infrastructure requirements for an oil-based hydrogen economy, including infrastructure for hydrogen distribution and storage, CO_2 transportation and storage (T&S) and finally the supply of feedstock. The section also describes the study's targeted regions (Middle East, West Africa, North Africa, Latin America and the North Sea) selected based on proven oil reserves and production capacity.
- **Section 5** describes the TEA methodology and presents the respective findings. This concerns the fifteen-hydrogen producing case study countries.
- **Section 6** describes the LCA methodology and presents the respective findings. This concerns the five hydrogen producing regions and associated sensitivities.
- **Section 7** identifies the key drivers, enablers, challenges and barriers for the wider deployment of oil-based hydrogen production.
- **Section 8** assesses the findings from this study, determines the strengths and weaknesses of the production pathways explored in this analysis and provides recommendations for further sector development.
- **The Appendices** provide supporting information and assumptions for the analyses carried out in this study.

[11] Blue Hydrogen Roadmap, Element Energy, 2021

2 Blue Hydrogen Production Technologies

2.1 Overview

More than 96.8% of today's hydrogen is produced from natural gas or coal without integrated CCS[12]. As explored in Section 3, this hydrogen is largely used by the industrial sector. As a result, coal gasification and steam methane reforming are the two most widely deployed hydrogen production technologies, both with high technology maturity.

However, the increasing demand for hydrogen as part of a net-zero emission energy system[13] requires a portfolio of hydrogen production technologies. This is expected to include hydrogen derived from oil and oil-based products. A selection of these technologies is discussed in this section, including those at laboratory and industrial scales and technology levels.

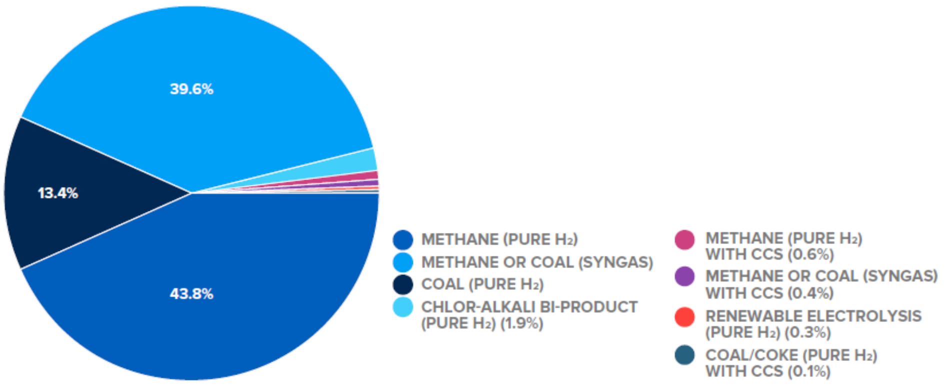

Figure 7: Global share of hydrogen production from different sources and processes in 2020[12]

Hydrogen Functional Unit Definition

To maintain consistency between analyses of select technologies, the hydrogen product is defined based on the associated carbon intensity and hydrogen purity.

Hydrogen Carbon Intensity

Internationally, there are no formal definitions which distinguish hydrogen production technologies by carbon intensity. Instead, a selection of "colours" is used based on the technologies used. However, there are a wide range of these definitions used across industry and academia and they are not harmonised. Four of the most common forms of hydrogen production are:

- **Green** – Production via electrolysis using renewable electricity.
- **Blue** – Production using fossil fuels with CCS.
- **Grey** – Production using natural gas or oil and no CCS.
- **Brown** – Production using coal and no CCS[14].

This study focuses on oil-based blue hydrogen production; however, the definition above leaves it open to interpretation on what carbon capture requirements actually constitutes as blue hydrogen. Using Europe as an example, organisations such as Hydrogen Europe[15] have recommended that formal definitions are introduced based on carbon intensity. Projects such as CertifHy[16] aim to develop a Guarantee of Origin for a new hydrogen market and have proposed a greenhouse gas (GHG) emission intensity 60% below the benchmark of hydrogen production from natural gas without CCS. Meanwhile, discussions on policy in the

[12] Global CCS Institute 2020, Global Status of CCS 2020
[13] Net zero refers to achieving a balance between the amount of greenhouse gas emissions produced and the amount removed from the atmosphere. Institute for Government 2019, UK Net Zero Target
[14] EIA 2021, Hydrogen Explained: Production of Hydrogen
[15] Hydrogen Europe 2020, The Eu Hydrogen Strategy: Hydrogen Europe's Top 10 Key Recommendations
[16] CertifHy 2019, CertifHy – The first European Guarantee of Origin for Green and Low Carbon hydrogen

European Union (EU) are more focussed on capture rates greater than 90%[17]. Whilst not directly correlated, this demonstrates the transition to lower-carbon forms of energy.

Capture rates in excess of 90% are widely used in the literature and are achievable for a range of technologies utilising advanced CCS systems. This study focuses on oil-based hydrogen production with CCS using a capture rate of 90% as a minimum. This significantly reduces the carbon intensity of the hydrogen, as shown in Section 6, when compared to grey hydrogen.

Hydrogen Purity

The purity of the hydrogen is reliant on the downstream processing and is typically determined by the end use requirements. Methanation and Pressure Swing Adsorbers (PSAs) are two processes commonly used in industry to increase the purity of hydrogen from a syngas stream. The methanation reaction occurs at temperatures of approximately 300°C and is performed to eliminate carbon monoxide (CO) and CO_2 impurities in the syngas stream. The methanation process is also done to reduce CO to safe levels (10 ppm) in the product hydrogen, below the proposed 20 ppm safety standard for heating applications (using the UK as an example[18]). In the methanation process, CO and CO_2 react with hydrogen to produce methane and water as shown by the equations below[19]. This achieves a hydrogen purity more than 95%.

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O \qquad \Delta H^0 = -206.6\ kJ.mol^{-1}$$

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \qquad \Delta H^0 = -165.5\ kJ.mol^{-1}$$

The PSA process is based on the physical binding of gas molecules to an adsorbent material. The process works at an almost constant temperature and utilises the effects of alternating pressure and partial pressure to perform adsorption and desorption[20]. Heating and cooling are not required as part of the process allowing short cycle times and the removal of large amounts of impurities. Hydrogen is recovered at close to the feed pressure, whilst impurities are removed by reducing the PSA pressure. The PSA process can reduce CO levels to less than 1 ppm. The tail gas containing the impurities can be recycled to refuel the system[21]. Where a PSA is used, purity can go beyond 99.999%; this is required by fuel cell applications.

The purity achieved by methanation is suitable for some industrial processes (where purities below 98% are acceptable) and blending into natural gas grids. PSAs are used industrially where high purity hydrogen is required.

The cost of hydrogen purification is a function of the required purity levels and leads to more hydrogen losses. This makes the impact on the LCOH challenging to calculate. For example, the LCOH of a methane fired SMR (including a hydrogen fired gas turbine) increases from 4.26p/kWh to 4.44p/kWh with methanation (CO<50ppm) and between 4.62p/kWh and 5.10p/kWh with a PSA (purity levels of CO less than 250ppm and less than 0.2ppm respectively)[22].

The technology configurations and process descriptions from literature vary between using a PSA and methanation step. Therefore, a minimum purity of 97% has been specified. This limits the ability to draw direct comparisons between processes, with cost differences of potentially between 4% and 14% for the highest-grade purity hydrogen.

2.2 Technology Screening Criteria

The project methodology for identifying the most appropriate oil and oil-based hydrogen production technologies for assessment in this study is outlined below.

The screening criteria focused on three key factors:

[17] Euractive 2020, Renewable or 'low-carbon'? EU countries face off over hydrogen
[18] Hy4Heat for BEIS 2019, Hydrogen Purity – Final Report
[19] Garbarino et al 2020, A Study on CO_2 Methanation and Steam Methane Reforming over Commercial Ni/Calcium Aluminate Catalysts
[20] Linde, Hydrogen Recovery by Pressure Swing Adsorption
[21] Air Liquide, Pressure Swing Adsorption (PSA) – Hydrogen Purification
[22] Hy4Heat for BEIS 2019, Hydrogen Purity – Final Report

1. **Future Technology Outlook** – Identifying technologies where developers and companies are active and raising funding to progress their technology's technology readiness level (TRL). This filters out those technologies that have been abandoned by developers, however, a lower TRL limit was not used to ensure developing technologies were considered e.g., HEE – TRL 4 to 6.
2. **Feedstock Diversity** – Identifying the oil and oil-based feedstocks for each technology and whether there is any flexibility in operation, i.e., accepting a range of oil-based feedstocks.
3. **Data Availability** – Satisfactory data availability is essential for robust TEA and LCA. Whilst there are a number of promising blue hydrogen production technologies in development, it is not possible to conduct analysis on all of them due to the absence of data.

The technology assessment process involved the following:

- **Preliminary Screening of Literature** – collating a list of technology options that can produce hydrogen from oil and / or oil-based products. Information came from a combination of company presentations, websites, research papers, patents, and textbooks. High level findings are outlined for each technology in this report.
- **Identification of Stakeholders** – identifying key stakeholders from the preliminary screening for both data corroboration and developing assumptions.
- **Selection of Technologies for Techno-Economic and Lifecycle Analyses** – the preliminary list of production technologies was reduced based on a combination of stakeholder interviews and the critical assessment of literature. Where data was limited or unavailable, project assumptions were tested in stakeholder interviews.
- **Workshops** – collated data was reviewed in internal project team workshops to determine final technology choices and process data. Final data selection was based on the reliability of sources and the advice of stakeholders.

Eight hydrogen production technologies which use oil and / or oil-based products as a feedstock were studied. Section 2.2.1 focuses on five technologies which did not pass the initial screening phase, discussing their respective technology processes, technology readiness levels, value chain position, stakeholders, and conclusions. Section 2.2.2 focuses on three technologies which passed the initial screening phase. A more detailed discussion is provided focusing on their respective technology processes, technology readiness levels, value chain position, stakeholders, and conclusions.

A table summarising the assessed technologies is shown in Table 1. A TRL range is presented for several of the assessed technologies. This is unique for all each technology. For example, pyrolysis is advanced but not to produce hydrogen from oil-based feedstocks, the TRL for HEE is predicted to progress imminently and there are uncertainties around the capability of diesel reforming for blue hydrogen production.

Table 1: Summary of assessed hydrogen production technologies

Technology	TRL	Supply Chain Position	Technology Developers / Stakeholders	Process Summary
Catalytic Naphtha Reforming	9	Refinery	Stakeholders: Honeywell, Phillips 66, Shell, BP, Saudi Aramco, Exxon Mobil, Petrobras, ADNOC, Chevron	Hydrogen is a by-product in the catalytic naphtha reforming process.
Pyrolysis	4-8	Refinery / Dedicated Plant	Kumho R & BD Centre, Sungkyunkwan University, Fraunhofer IMM	Decomposition of feedstock in an inert atmosphere to produced pure hydrogen and solid carbon.
Plasma Reforming	4	Mobile Unit / Dedicated Plant	University of Cambridge, Ming Chi University of Technology	Very high temperature reforming controlled via electricity. Plasma reforming can utilise a range of feedstocks and high conversion efficiencies have been achieved at lab scale.
Diesel Reforming	3-4	Mobile Unit	Naval Group, Tenneco	On-board reforming technology produces hydrogen for use in fuel cells in the marine and trucking industries.
HyRes	3–4	Refinery	TDA Technologies	Continuous production of hydrogen from steam reforming of waste oil streams such as residuum.
Steam Naphtha Reforming	9	Refinery	Woods Group, Linde, Johnson Matthey, Air Liquide	Steam reforming of light oil-based feedstocks to produce a stream of hydrogen and carbon monoxide.
Partial Oxidation	9	Refinery / Dedicated Plant	Air Products, Air Liquide, Linde, Shell	Partial oxidation of oil-based feedstocks at high temperatures to produce a stream of hydrogen and carbon monoxide.
Hygienic Earth Energy	4–6	Fossil Fuel Reservoir	Proton Technologies	Heating oil reservoirs by injecting oxygen deep underground allowing pure hydrogen to be extracted with no emissions.

2.2.1 Blue Hydrogen Production Technologies - Not Selected for Analysis

This section focuses on five technologies which did not pass the initial screening phase, discussing their respective technology processes, technology readiness levels, value chain position, stakeholders, and conclusions.

Catalytic Naphtha Reforming

Process Description

Catalytic Naphtha Reforming (CNR) produces hydrogen as a by-product in the naphtha refining process and is used primarily for upgrading low octane gasoline and producing aromatic rich feed streams for petrochemical processes. CNR is widely deployed within refineries with by-product hydrogen used for:

- Sulphur and nitrogen removal from crude oil.
- Producing jet fuel, diesel, high-octane gasoline, and liquid petroleum gas from heavy oil feedstocks[23].

[23] Stijepovic et al 2012, Toward enhanced hydrogen production in a catalytic naphtha reforming process

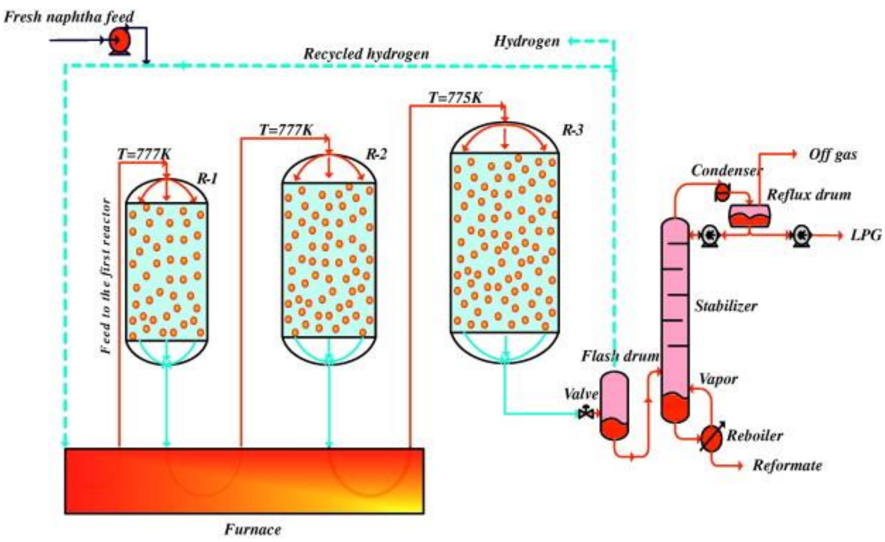

Figure 8: Catalytic Naphtha Reforming[24]

The CNR process involves a set of chemical reactions that occur on the catalyst surface. Reactions that increase hydrogen production are desirable and systems aim to maximise the yield of by-product hydrogen where possible. A stream of hydrogen and heavier components is produced by the CNR process with a flash unit used to separate hydrogen and other light gases from these heavier components. A schematic of the CNR process is shown in Figure 8.

Technology Readiness Level

The CNR process is widely deployed commercially and is at a TRL 9. The process has been used to produce by-product hydrogen used for upgrading fuels for decades. The CNR process is only deployed in refineries with no data found in literature of the technology being utilised for dedicated hydrogen production. No evidence has been found of the CNR process being integrated with CCS, however, this is likely to be included with the overall refinery facility for future CO_2 abatement, including capture from off gas.

Value Chain Position

The CNR process is used in refineries that process hydrocarbon feedstocks. Typically, the process is heavily integrated into the refinery as naphtha feedstock is widely available and hydrogen offtake is required by upgrading processes within the refinery. The CNR process is unlikely to meet the hydrogen demand of the refinery (known as the hydrogen balance) and dedicated on site hydrogen production or commercial supply is therefore required. This is typically delivered by conventional SMR or gasification plants that have become increasingly popular as hydrogen demand has increased due to greater demand for hydro processing in refineries to produce lighter low-sulphur fuels[23].

Technology Developers

Stakeholder engagement highlighted that hydrogen production from the CNR process has traditionally only been integrated into refineries to produce by-product hydrogen used within the refinery. Although efforts are made to maximise the hydrogen yield in this process, the technology is unlikely to ever be utilised for dedicated hydrogen production.

Conclusions

The CNR process has not been selected for further analysis due to the process being heavily integrated into the overall refinery setup, resulting in technical and economic data being challenging to isolate and extract. The process is likely to be integrated as part of a wider refining facility and emissions associated with the CNR process are likely to be combined with other process streams that could be captured from a centralised CCS

[24] Rahimpour et al 2013, Progress in catalytic naphtha reforming process: A review

system. The potential for reducing the carbon intensity of the product hydrogen is therefore unclear with the integration of dedicated CCS for blue hydrogen production yet to be analysed.

Pyrolysis

Process Description

Pyrolysis is defined as the thermochemical decomposition of a feedstock, conventionally biomass or natural gas but this also includes other hydrocarbons, at medium (300-800°C) to high temperatures (800-1,300°C) in an inert atmosphere (in the absence of oxygen). This leads to the production of pure hydrogen and solid carbon (a waste product that can be processed into carbon black) as shown in Figure 9. It is possible to accelerate the process with the inclusion of catalysts. This is known as thermocatalytic decomposition.

The catalytic pyrolysis of propane for hydrogen production method is a key research area at laboratory scale. Studies have shown pyrolysis of liquid hydrocarbons is more favourable than the thermal decomposition of methane as approximately 1.5 to 2 times less energy is required to produce a unit volume of hydrogen. Propane, for example, has a weaker C-H bond than methane; this makes it easier to break[25].

Technology Readiness Level

Pyrolysis of oil and oil-based products is currently at a TRL 4; however, pyrolysis of natural gas feedstock is currently at TRL 8. Monolith, a US based company have developed the world's first commercial scale (~19 MW) methane pyrolysis facility at Olive Creek 1 in Nebraska[26] producing low carbon hydrogen and solid carbon that can be processed into clean carbon black. Monolith aim to advance methane pyrolysis technology to TRL 9 with the development of Olive Creek 2, set to come online in 2024.

Hydrogen production via pyrolysis of oil-based feedstocks currently includes propane and gasoline at laboratory scale. Advancements in technology and the associated TRL is expected with further research and development and project demonstration at scale. Hiiroc are a UK based company developing a unique plasma pyrolysis process for producing hydrogen and solid carbon[27]. The process is currently in the early stages of development and will be compatible with a range of feedstocks including propane, butane and LPG.

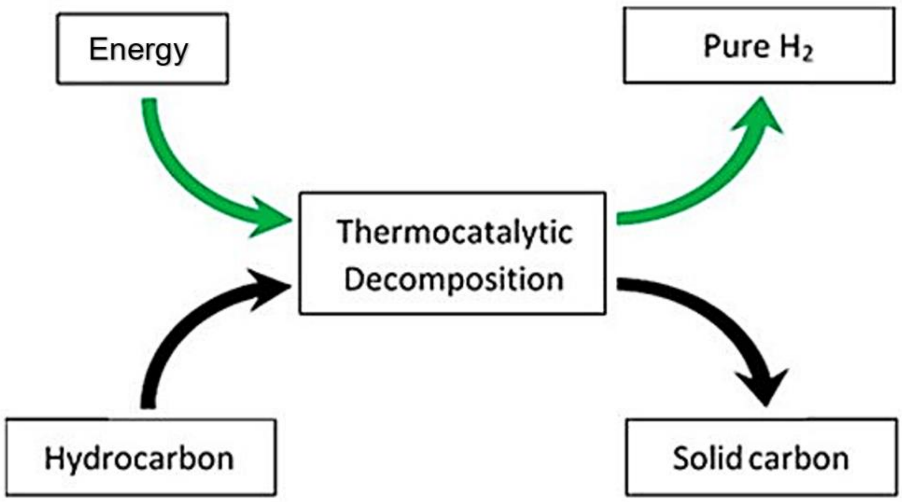

Figure 9: Inputs and outputs of Thermocatalytic Decomposition (adapted)[28]

Value Chain Position

Pyrolysis of propane is targeted at producing hydrogen in refineries. Propane is widely available as a fuel in refineries and pyrolysis would be suited to meeting the high on-site hydrogen demand for the refining process.

[25] A total of 6.2 kcal/mol is required to produce one mole H_2 from propane, comparing that to 8.9 kcal/mol for methane. Muradov, N 2000, Thermocatalytic CO_2-Free Production of Hydrogen from Hydrocarbon Fuels
[26] Monolith 2020, Company Introduction
[27] HiiROC 2021,Hydrogen – the new global green fuel
[28] Vander Wal and Nkiawete 2020, Carbons as Catalysts in Thermo-Catalytic Hydrocarbon Decomposition: A Review

It is expected that the pyrolysis process would also accept other oil-based fuels such as liquefied petroleum gas (LPG) and butane, which are also widely available in refineries. However, there is currently limited research and data available in this area.

Deployment at scale could occur in those regions which currently rely on natural gas fired Steam Methane Reforming (SMR) hydrogen production, but where propane feedstock can be sourced at lower cost than natural gas. Deployment may be possible in countries that rely heavily on the imports of natural gas.

Technology Developers

Research institutions, such as the Kumho Petrochemical R&BD Centre (Korea), Sungkyunkwan University (Korea) and Fraunhofer IMM (Germany), are the main proponents of the pyrolysis of oil-based feedstocks for hydrogen production. Pyrolysis is not explored by the major oil and gas companies as a current technology for large scale hydrogen production.

Conclusions

Pyrolysis has not been selected as a technology for further analysis due to the lack of data availability for hydrogen production using oil-based feedstocks. Pyrolysis conventionally utilises natural gas or organic feedstocks with oil-based pyrolysis currently limited to laboratory scale research. Stakeholders looking to advance the development of pyrolysis technology for oil-based feedstocks are yet to develop a successful demonstration scale project. The low yields of hydrogen from this production method, when compared to incumbent processes, is also a limiting factor in its commercialisation and wider deployment.

Plasma Reforming

Process Description

In plasma reforming, energy and free radicals used for conventional reforming reactions are provided by plasma generated by electricity or heat[3]. The plasma reformer can generate very high temperatures (>2,000°C) and is controlled via electricity. Heat supplied to the reaction is independent of reaction chemistry and therefore allows the user greater control to operate the system in ideal conditions. Plasma reformers are significantly smaller than conventional hydrogen production systems due to the high energy density of the plasma (a superheated gas made of charged particles) itself. Reactor designs are therefore compact and low weight in comparison to conventional hydrogen production systems due to the high-power density of the plasma. A plasma enabled reactor system is shown in Figure 10.

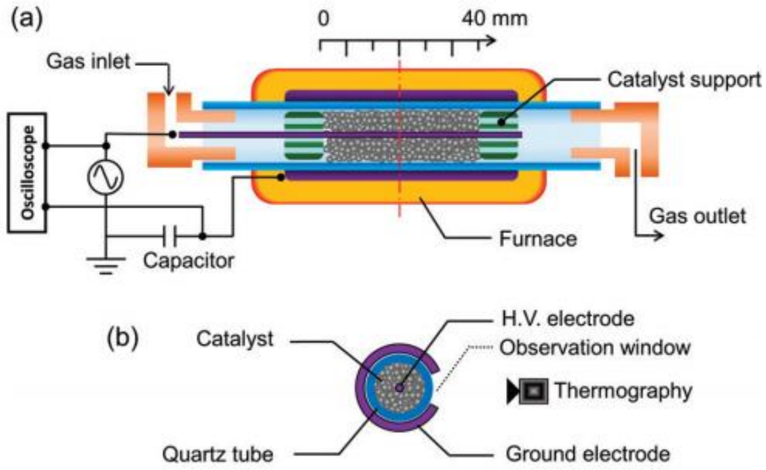

Figure 10: Single stage Dielectric Barrier Discharge (DBD) reactor system for dry methane reforming[29]

It is therefore theoretically possible to install plasma reformers in SMR, Auto Thermal Reforming (ATR) and Partial Oxidation (POX) configurations to produce syngas with high H_2 content. The technology is also able to

[29] Sheng et al 2018, Plasma-Enabled Dry Methane Reforming

utilise a range of feedstocks for hydrogen production, such as gasoline, diesel, oil and jet fuel. Experimental conversion efficiencies have been reported as close to 100%[3]. This has increased interest in the technology's potential as the high conversion rate can mitigate the need for some steps of the water gas shift reaction, conventionally required to increase feedstock conversion rates.

As the plasma can be supplied via electricity, there is interest in the potential for emissions reduction by supplying the plasma electrification process with renewable power rather than grid electricity. However, as current interest in the process is for small scale deployment, there are concerns about the potential economics for integration with CCS technology as traditionally this has only been economical for large scale systems. Utilising plasma reforming is currently focused on smaller scale (i.e. containerised units) applications however, benefits from integrating the technology at larger scale may result in increased efficiencies in future hydrogen production systems. Evidence of plasma reforming for blue hydrogen production is not available in literature at the time of writing.

Technology Readiness Level

Plasma reforming is currently at a TRL 4. However, advances are expected as researchers maximise the achievable benefits from the high potential conversion efficiencies. A decade's worth of laboratory scale demonstration supports these activities, considering different reactor technologies. These include Plasmatron, Gliding arc discharge, Microwave, Dielectric Barrier Discharge, Corona Discharge and Glow Discharge technologies[30]. University research appears to be focussed on mobile applications and containerised units.

Value Chain Position

It is technically viable to deploy this technology in existing industrial facilities and expand conventional hydrogen production facilities with plasma reactors. The cost impact of deploying plasma reactors in existing industrial facilities is currently unknown. However, a key benefit of plasma reforming is the achievable high energy density. Research has therefore explored mobile applications where small-scale hydrogen production is likely to be advantageous, particularly since economies of scale are not required for these electrical systems[3]. One consideration is to use containerised units which make the technology mobile. This ensures that hydrogen production occurs close to both the point of demand and source of oil-based feedstock. This would also provide the opportunity for modular expansion of production if increased capacity were required.

Technology Developers

Research conducted by stakeholders at the University of Cambridge and Ming Chi University of Technology states that large scale deployment of plasma reforming is unlikely to ever be cost competitive with conventional or alternative hydrogen production technologies. Stakeholders state that the size and energy requirements of plasma reformers required for large scale hydrogen production are likely to be cost prohibitive compared to other developing blue hydrogen production technologies. The future of plasma reforming is predicted to be for small scale and mobile applications where the technology provides competitive advantages. Currently, the technology is being developed by universities and research institutes.

Conclusions

Plasma reforming has not been selected for further analysis due to a lack of process and economic data currently available. In addition, there are several technical aspects that would still need additional assessment before commercialisation. For example, the integration of CCS is yet to be assessed and the technology is likely to be suited to small scale and mobile applications.

Diesel Reforming

Process Description

Petroleum-derived hydrocarbon fuels such as diesel have a high energy density. This makes them popular for transportation, military and industrial applications. The existence of established refuelling infrastructure has made diesel the fuel of choice for both individual consumers and commercial operations for many years.

[30] El-Shafie et al 2019, Hydrogen Production Technologies Overview

Recently, interest has been shown in the portable, on demand reformation of diesel to produce hydrogen in the marine and trucking industries. Hydrogen produced on-board ships, submarines and trucks could be utilised to power on-board fuel cell systems. On-board diesel reforming would allow existing refuelling infrastructure to be utilised whilst hydrogen infrastructure is developed. The technology could therefore provide an effective solution in the transition to a future hydrogen economy.

On-board diesel reforming follows a similar process to a large-scale ATR or POX reactor. Diesel, oxygen and steam are required as inputs which the reformer converts to a hydrogen rich syngas. The syngas is subsequently fed through a water gas shift reactor that increases the hydrogen conversion rate. This is achieved by converting carbon monoxide and water in the syngas stream into CO_2 and hydrogen. High purity hydrogen is produced by feeding the syngas through a specialised membrane, unlike a conventional reactor where a PSA or methanation step would be used. This high purity hydrogen can then be utilised by the on-board fuel cell to generate electrical power. A flow diagram of this process is shown in Figure 11.

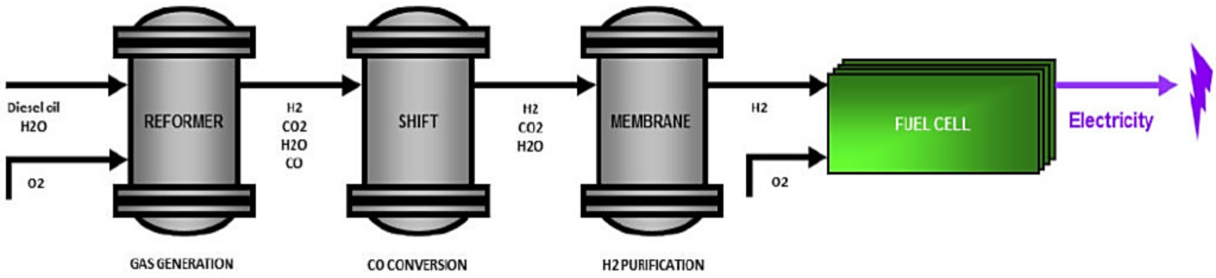

Figure 11: On-board diesel reforming block flow diagram[31]

Technology Readiness Level

On-board diesel reforming is currently at TRL 3-4. A laboratory scale demonstration was conducted by the Naval Group that successfully demonstrated how on-board diesel reforming could be integrated into submarine systems[31]. Research has also been published which demonstrates how on-board diesel reforming could be used to fuel Auxiliary Power Units (APUs)[32]. APUs provide power to on-board electrical systems such as climate control, infotainment systems and vehicle computers that consume significant amounts of power when fully operational. This is of particular interest for the trucking industry where significant emissions are produced when engines are left idling. Laboratory scale demonstration of the technology validates that diesel feedstock can be used in the reformation process to produce hydrogen. Although small scale capture systems are yet to be demonstrated operating alongside on-board reforming systems, mobile capture technology is likely to be an area of future interest and development for blue hydrogen production.

Value Chain Position

On-board diesel reforming is applicable to mobile applications that can utilise electrical power generated by fuel cells. This is of particular interest in military applications where fuel cells would allow armed forces to produce electricity with a very low heat and noise signature; as well as for fuelling APU's to reduce CO_2 emissions.

On-board reforming has the potential to utilise a range of oil-based feedstocks other than diesel. Petroleum derived feedstocks including gasoline, n-heptane, butane, propane, ethane, and jet fuel could be used as alternatives to diesel[33]. These products are widely available from refineries. However, interest has predominantly been shown in diesel-based feedstocks due to its relatively low-price, high-energy density and the existing refuelling infrastructure.

[31] Naval News 2019, Naval Group Achieves Breakthrough With Its FC2G AIP System
[32] Womann et al 2009, Fuel Cell Technology – HyTRAN Project
[33] Cozzolino and Tribioli 2015, On-board diesel autothermal reforming for PEM fuel cells: Simulation and optimization

Technology Developers

The Naval Group and Tenneco (both international companies) were identified for the development of their proprietary technology for on-board reforming in submarines and trucking, respectively. However, both organisations are yet to commercialise their technology and development in on-board reforming for hydrogen production appears to be limited. On-board reforming would also require integration with mobile carbon capture systems, a technology that is currently in the early stages of development by Aramco[34].

It is unclear if on-board reforming technology is cost prohibitive in comparison to large scale centralised hydrogen production facilities supplying hydrogen directly to fuel cell powered transport as well as competing directly against battery electric vehicles.

Conclusions

On-board diesel reforming has not been selected for further analysis due to the lack of process and economic data currently available. The integration of CCS is yet to be analysed and the technology is likely to be suited to small scale applications of hydrogen production.

Production of Hydrogen from Residuum (The HyRes Process)

Process Description

The HyRes process can generate hydrogen from residuum feedstocks (a residue from crude oil that remains after distilling of all but the heaviest components) via steam reforming. Residuum feedstocks are fed directly into the reforming process without undergoing initial pre-treatment. The resultant syngas stream contains approximately 70% H_2 by volume. This is subsequently increased via the water gas shift reaction where catalytic reactions between carbon monoxide and steam facilitate the production of additional hydrogen.

This process provides an economically attractive solution for converting waste streams into a valuable product. The process allows for the continuous production of hydrogen (or syngas) with a solid catalyst whilst avoiding deactivation or irreversible coke formation on the reactor surface[35]. The process is much simpler and less expensive than conventional gasification as the process takes place without the need for an energy intensive air separation unit (ASU) whilst operating at lower temperatures than partial oxidation/gasification, typically 850°C. It is also more suitable for smaller refineries and distributed plants with capacities of approximately 50,000 barrels per day[36]. This is because the process provides a method of hydrogen production without the need for the development of a dedicated SMR or POX facility, which are typically only installed to meet high demand for hydrogen. A schematic of the process flow is shown in Figure 12.

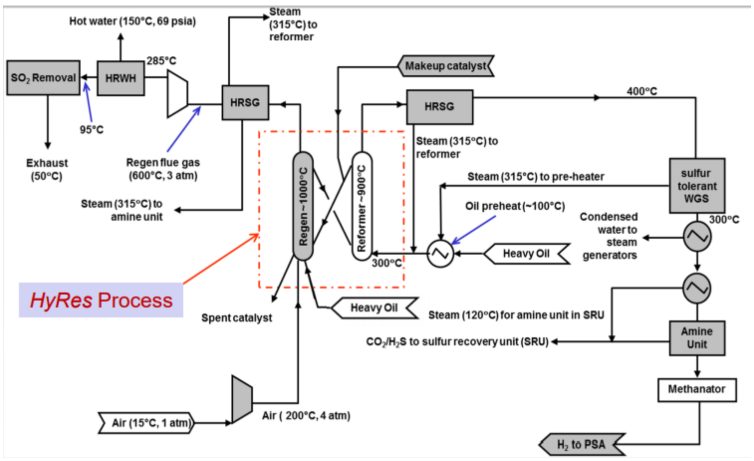

Figure 12: HyRes process[35]

[34] OGCI 2021, SAUDI ARAMCO Advancing carbon capture in the transport sector
[35] Srinivas, G 2014, Hydrogen Generation for Refineries
[36] TDA Research Inc 2015, Process for generating hydrogen from heavy oil or hydrocarbons

The process has been tested using residuum from atmospheric and vacuum tower bottoms which typically produce the heaviest residues in refineries. However, the HyRes process could utilise various feedstocks such as bitumen, pyrolysis oil produced from biomass and waste oil[35]. The technology is yet to be analysed with integrated CCS technology and it is therefore unclear on its suitability for blue hydrogen production.

Technology Readiness Level

The HyRes process is currently at TRL 3-4. The technology is currently lab based with no evidence of it being utilised in existing refineries according to literature. The most up to date information on the process is from 2015 and the lack of published data suggests that the process has not advanced beyond laboratory scale testing. It is unclear if the process has been determined to be an unviable option for commercial hydrogen production or if the technology development has been temporarily postponed. As global hydrogen demand increases, development of the HyRes process may resume as refineries look to develop methods of generating additional value from waste process products as this is shown to result in significant economic benefits.

Value Chain Position

The HyRes process, according to literature, is most suited for integration in refineries and chemical plants due to the feedstock requirements. Heavy residues with low economic value are widely available in crude oil processing refineries that could be utilised for hydrogen production. The technology has therefore been developed with the aim of generating additional hydrogen capacity from waste products.

Technology Developers

TDA Technologies patented the HyRes process in 2015[36]. However, there has been no data published more recently about the process. It is currently unclear if TDA Technologies aim to advance the TRL of the HyRes process further with the goal of deploying it commercially in the future, or if the technology development has been postponed.

Conclusions

The HyRes process has not been selected for further analysis due to a lack of process and economic data currently available. The process is likely to be integrated as part of a wider refining facility and emissions associated with the HyRes process are likely to be combined with other process streams that could be captured from a centralised CCS system. The potential for reducing the carbon intensity of the product hydrogen is therefore unclear with the integration of dedicated CCS for blue hydrogen production from this process yet to be analysed.

2.2.2 Blue Hydrogen Production Technologies - Selected for Analysis

Steam Naphtha Reforming

Process Description

Steam Naphtha Reforming (SNR) is an almost identical process to conventional SMR. SMR plants are widely deployed at scale industrially and account for nearly 50% of world hydrogen production[3]. Plants are typically sized between 25-500 tonnes of hydrogen per day (35-700MW) and are consistently cited in literature as one of the lowest cost methods of hydrogen production. Natural gas (which is made up of primarily methane) has traditionally been used as both a fuel and feedstock for the SMR process; however, there has recently been a growing interest in the potential for the configuration to be utilised with oil-based feedstocks for blue hydrogen production. Naphtha and other light oil-based hydrocarbons such as LPG and, in some cases, kerosene can replace natural gas as the feedstock in conventional SMR configurations[30].

SNR involves a naphtha feedstock that is first fed through a pre-treatment unit that ensures impurities in the feed are removed before entering the reformer. The treated naphtha feed is then fed through a pre-heater and pre-reformer alongside a recycled hydrogen stream. This allows the temperature of the feed stream to be increased sufficiently to ensure coke formation is eliminated from the process. This can cause an undesirable catalyst deactivation. Heavier hydrocarbons are converted to methane, hydrogen and carbon oxides allowing the system to operate at lower steam to carbon ratios, and thus reducing the overall energy consumption of the process[37]. The heavier the oil-based feedstock, the greater the pre-reformer energy requirements, which can be a limiting factor in the use of heavier oil-based feedstocks. This stage reduces the required reformer tube area, resulting in a lower capital cost. This stream is then combined with steam and fed into the main reactor for the steam reforming reaction. A schematic of this process is shown in Figure 13.

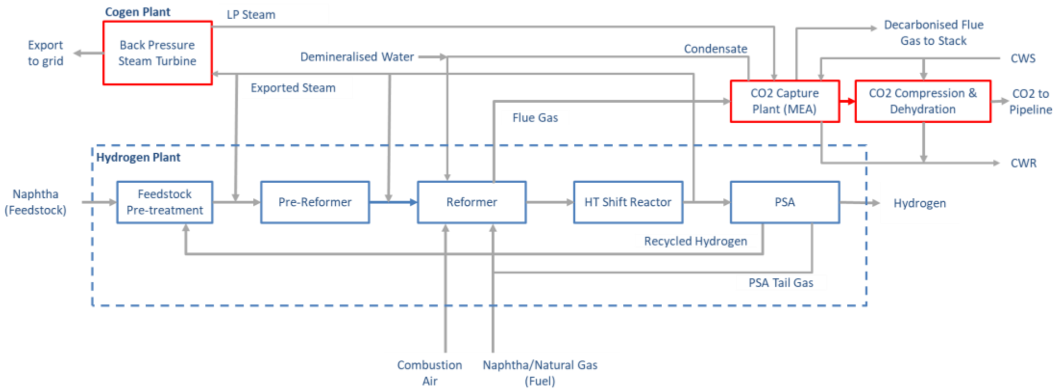

Figure 13: Steam Naphtha Reforming process flow (adapted)[38]

Because the process is endothermic, it requires the transfer of energy into the system in the form of heat. This process is typically powered by natural gas (which is typically cheaper than naphtha) and, when combined with a steam boiler, can result in an overall increase in efficiency. This configuration also allows for excess steam to be exported or used to generate electrical power. Naphtha feedstock is produced from crude oil distillation and typically varies significantly in composition by region and refinery. Naphtha is typically split into light and heavy variants. Light naphtha variants typically have between 5-6 carbon atoms[39], whilst heavy naphtha variants typically have from 7-9 carbon atoms[40]. The chemical equation for steam reforming of paraffins/alkanes (C_nH_{2n+2}), which constitute the vast majority of naphtha composition, is shown below[41]:

$$C_nH_m + nH_2O \rightarrow \left[n + \frac{1}{2}m\right] H_2 + nCO$$

E.g., Steam reforming of iso-octane (C_8H_{18}):

$$C_8H_{18} + 8H_2O \rightarrow 17H_2 + 8CO \qquad \Delta H^0 = 1{,}274.8kJ.mol^{-1}[42]$$

Technology Readiness Level

Steam Naphtha Reforming is at TRL 9 and is currently available at commercial scale. The process utilises the same configuration as conventional steam methane reforming technology that is deployed for hydrogen production worldwide. The utilisation of naphtha as a feedstock has been limited in comparison to natural gas, primarily as naphtha is a refined oil product with greater value than natural gas. If the price of naphtha were to fall below natural gas or could be supplied at lower cost, existing SMR's could be switched from natural gas to naphtha-based feedstocks. There are currently no SNR facilities operating with CCS, however, both pre- and post-combustion capture configurations could be integrated into the process for blue hydrogen production.

Value Chain Position

Steam methane reforming is currently used for dedicated hydrogen production, primarily supplying refineries and chemical production facilities that produce products such as methanol and ammonia. As the process uses natural gas for both fuel and feedstock, the technology can be deployed easily in regions with a natural gas network. However, if naphtha feedstock is utilised in SNR, transporting the feedstock to the production site becomes a more significant challenge for the process. As naphtha is a product produced in refineries from the

[37] IEAGHG 2017, Reference data and Supporting Literature Reviews for SMR based Hydrogen Production with CCS
[38] IEAGHG 2017, Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS
[39] Encyclopedia of Physical Science and Technology (3rd Edition) 2003, Light Naphtha
[40] McKinsey & Company 2021, Heavy Naphtha
[41] Ibrahim, A 2018, Hydrogen Production from Light Hydrocarbons
[42] Praharso et al 2004, Kinetic study of iso-octane steam reforming over a nickel-based catalyst

distillation of crude oil[39], deploying SNR technology near to refineries where naphtha will be readily available can reduce feedstock costs. This would also apply if the process were to be used with other light oil-based products unless existing fuel transportation infrastructure could be utilised e.g., LPG transportation via ship. Economies of scale are achievable by siting the technology near to industries where hydrogen offtake will be readily available and shared CO_2 T&S infrastructure is more likely to be developed. However, if a region does not have any suitable sites for CO_2 storage nearby, the cost of CCS could make the SNR process uneconomic as a blue hydrogen production process.

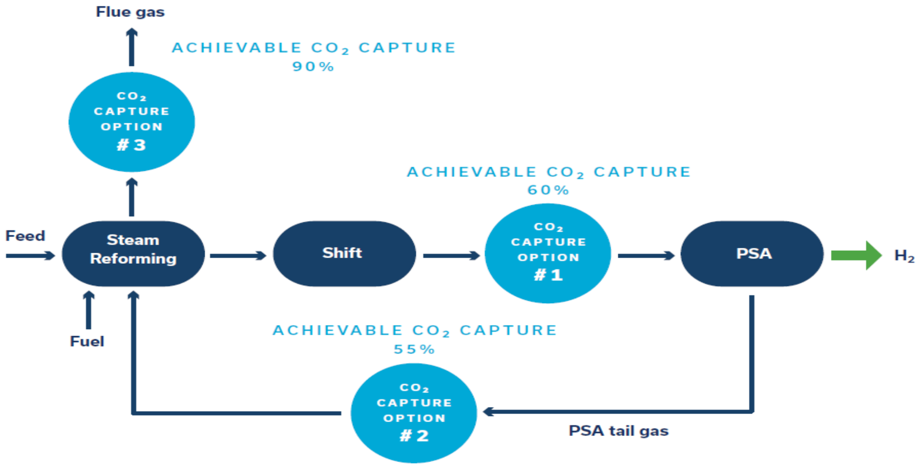

Figure 14: Potential locations for CO_2 capture for SNR technology[43]

The process can utilise both pre- and post-combustion CCS configurations as shown for the Port Arthur, Texas hydrogen production facility in Figure 14. Pre-combustion carbon capture can be located on the syngas or PSA tail gas streams, whereas post-combustion CCS can be located on the flue gas stream. Post-combustion CCS is the most mature capture technology and is the most suitable option for retrofit[44]. This has the added benefit of higher capture rates of at least 90%.

Technology Developers

There are a range of commercial steam reforming technologies available on the market from companies such as Air Liquide, Linde, Air Products, Woods, and Johnson Matthey. Stakeholders currently focus on the reforming of natural gas feedstock, however, there is potential for the technology to utilise oil-based feedstocks as outlined previously. Advice from stakeholders stated that light oil-based feedstocks could be utilised, such as light naphtha and LPG, without significant plant modification. Gasification of the feedstock is crucial, with a pre-reforming stage required for heavier oil-based feedstocks.

Process Data

Process data was collected from a combination of literature and stakeholder engagement. Data collected for the SNR process is presented in the Appendices, Section 9.2.2. Uncertainties within the process are analysed as sensitivities as part of the techno-economic assessment of the technology.

Partial Oxidation

Process Description

POX (or oil gasification for liquid feedstocks) is an exothermic process (heat is produced during the reaction) where the feedstock is gasified at very high temperatures (1,300-1,500°C) in the presence of oxygen and steam. The difference between the POX and gasification processes is determined by the state of the feedstock. POX refers to both liquid and gaseous streams whilst gasification can also refer to liquids as well as solid

[43] IEAGHG 2018, The CCS Project at Air Products' Port Arthur Hydrogen Production Facility
[44] Leung et al 2014, An overview of current status of carbon dioxide capture and storage technologies

based feedstocks[45]. Gasification is one of the primary methods of hydrogen production in the world today with the gasification of coal feedstocks popular in regions where natural gas is of higher cost than coal e.g., China[4].

A key advantage of the POX process is its ability to process heavy hydrocarbon feedstocks, with the process traditionally utilised in refineries to produce syngas[46]. Recently, there has been significant interest in the process as a method of blue hydrogen production. The POX process does not require a catalyst for operation, unlike conventional SMR hydrogen production. The chemical equation of partial oxidation is shown below[41]:

$$C_nH_m + \frac{1}{2}nO_2 \rightarrow \frac{1}{2}mH_2 + nCO$$

For example, the partial oxidation of butane (C_3H_8) is shown below[47]:

$$C_3H_8 + \frac{3}{2}O_2 \rightarrow 3CO + 4H_2 \qquad \Delta H^0 = -229kJ.mol^{-1}$$

The POX process has a proven track-record for processing a wide range of feedstocks, including highly viscous, high sulpher residues without the requirement of feedstock pre-treatment[3]. This creates opportunities for using waste streams from industrial processes as a feedstock.

The process utilises oxygen as the primary reactant. The oxygen is typically produced by cooling and compressing the ambient air in an ASU. Oxygen purity of >99% is typically used to increase process efficiency; however, this is determined by the facility requirements. This is a significant energy requirement of the process and has typically been the factor limiting further uptake of the technology. However, due to the exothermic nature of the reaction, no additional heat is required for the process. The process also occurs at a higher pressure and temperature than the SMR process, which can be advantageous as it reduces downstream compression requirements.

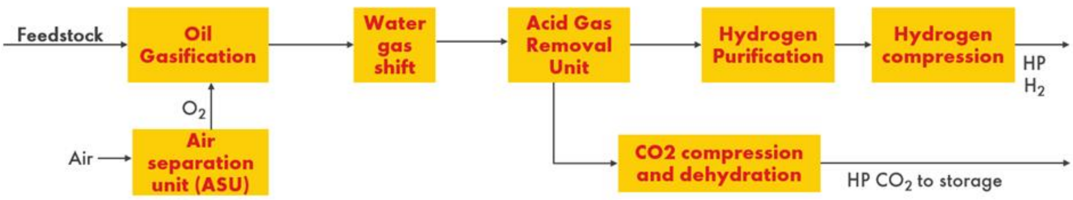

Figure 15: Shell Gasification Process (SGP) blue hydrogen production process[48]

The syngas stream leaving the POX reactor contains a mixture of primarily hydrogen and CO. This is then fed into the water gas shift reactor, which converts the remaining carbon monoxide into hydrogen. As there is no additional heat supplied to the process, pre-combustion CCS configurations can be utilised. Figure 15 depicts Shell's hydrogen production process. The hydrogen stream is subsequently purified using a methanation step where the remaining CO and CO_2 are converted to methane and raw water. The methanation step can achieve purities of 95-97%, but if higher purities are required, a PSA can be utilised to produce hydrogen purities of 99.999%.

Technology Readiness Level

Partial Oxidation is at TRL 9. Gasification technology was developed in the 1950's by Shell and Texaco to produce hydrogen and syngas to supply to industrial processes. The process is typically deployed where low value waste products or heavy feedstocks can be utilised to produce valuable hydrogen or syngas. POX technology is currently available at commercial scale; and is often applied to produce hydrogen. This scheme also offers the opportunity to capture CO_2 at high purities from the acid gas removal unit that would turn this scheme into an alternative way to produce blue hydrogen.

[45] NETL 2020, Oil And Gas Partial Oxidation
[46] Linde 2007, Industrial Hydrogen Production & Technology
[47] Hognon et al 2012, Hydrogen Production by Homogeneous Partial Oxidation of Propane
[48] Shell 2020, Affordable blue hydrogen production with the Shell Blue Hydrogen Process

Value Chain Position

POX is typically used in refineries that process heavy hydrocarbon feedstocks, including low-value / waste oil feedstocks such as vacuum residue, (deep) thermal cracking residue and solvent de-asphalting residue. Traditionally, the process has been located in refineries due to the high availability of feedstocks and demand for hydrogen and / or syngas as a product; however, the process could be utilised for dedicated blue hydrogen production in the future. Economies of scale are achievable by siting the technology near to industries where hydrogen offtake will be readily available and shared CO_2 T&S infrastructure is more likely to be developed.

Pre-combustion carbon capture can be located on the syngas stream. This has many advantages over post combustion capture systems that give higher capture rates for conventional SMR hydrogen production facilities[49]. The syngas stream is at higher pressure to the flue gas stream which results in a higher partial pressure of CO_2. High capture rates can therefore be achieved with lower energy requirements with capture rates >95% cited in literature. CO_2 captured from the syngas stream is also at higher pressure, reducing energy demand and number of stages required for compression of CO_2 prior to transport and storage. However, the fuel conversion (converting oil to hydrogen) steps[50] required for pre-combustion CO_2 capture are more complex than those for post-combustion capture. This can make retrofitting pre-combustion capture technology more challenging than post-combustion as increased plant integration with the existing facility is required[51].

Technology Developers

There are a range of commercial gasification technologies available on the market, provided by companies such as Air Liquide, Shell and Air Products (formal GE technology). Shell and Air Products are in an alliance to actively pioneer POX technology for blue hydrogen production. Engagement with stakeholders outlined how the POX process' ability to utilise a range of feedstocks can make the process very economically attractive when low-value or waste feedstocks are utilised.

Process Data

Process data was collected from a combination of literature and stakeholder engagement and is presented for the POX process in the Appendices, Section 9.2.2. Uncertainties within the process are analysed as sensitivities as part of the techno-economic assessment of the technology.

Hygienic Earth Energy

Process Description

Hygienic Earth Energy (HEE) is a process patented by Proton Technologies[52], a Canadian based company. Proton Technologies has developed a method of producing large quantities of blue hydrogen from oil-based feedstocks. HEE utilises established technologies from the hydrogen production and oil and gas industries and deploys them in a new configuration. The process involves the combination of heating hydrocarbon reservoirs by injecting high purity oxygen deep into the reservoir, whilst harvesting pure hydrogen through a selective membrane. Proton Technologies patented "Ox-injection" and "Hygeneration" wells are used to inject the oxygen and extract the hydrogen, respectively. The process has the following key steps and is described further below:

- Oxygen enhanced air is pumped underground into the oil reservoir.
- Instantaneous oxidation (in-situ combustion) occurs as oxygen combines with the hydrocarbon fuel. Additional oxygen helps sustain this reaction.
- Heat is produced by a range of chemical reactions including oxidation, gasification, pyrolysis, aqua-thermolysis and water gas shift reactions. Throughout this process, these reactions also split the hydrocarbons into their basic elements.

[49] IEAGHG 2017, SMR Based H_2 Plant With CCS
[50] Pre-combustion processes convert fuel (e.g. natural gas) into a gaseous mixture of hydrogen and CO_2.
[51] Global CCS Institute 2020, Capturing CO_2
[52] Patent 2017, In-Situ Process to Produce Hydrogen from Underground Hydrocarbon Reservoirs

- Palladium membranes are inserted deep into wells and designed only to extract pure hydrogen gas. All CO_2 emissions remain stored underground.

A schematic showing the key steps of the HEE process is shown in Figure 16.

An air separation unit (ASU) located above the reservoir produces oxygen, which is then injected into the wells. The most energy intensive part of the hydrogen production process is running the ASU. However, the hydrogen extracted from the well can be used to run a hydrogen generator to produce electricity; this can be used to run the ASU unit and other auxiliary electrical equipment (e.g., pumps and compressors) and there is therefore no need to import electricity from the grid. Approximately 15.2% of the extracted hydrogen is required to fuel the hydrogen generator to meet the hydrogen production facility electrical demands[53].

This report does, on the other hand, considers sensitivities where grid power is used to explore the economic and environmental implications. The base case assumes that the HEE hydrogen plant produces electricity onsite using a hydrogen generator[54], as established by the primary stakeholder, Proton Technologies. This electricity is used to supply the ASU for oxygen production and meet auxiliary electrical demands. However, an on-site hydrogen generator is not essential for the HEE process where grid connections are feasible. The technology operator must optimise this configuration based on factors such as price of feedstock and electricity. Connection to the electricity grid is therefore explored as a sensitivity in the techno-economic and life cycle analysis sections.

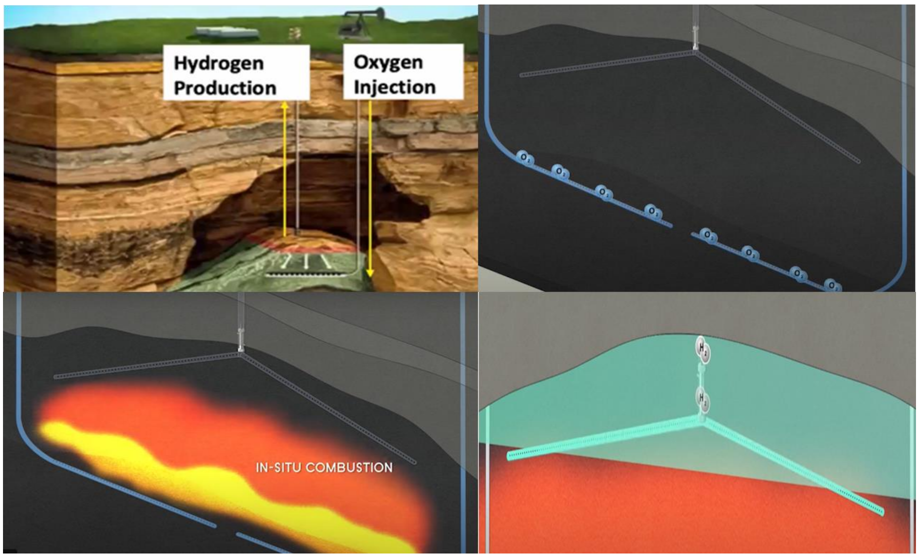

Figure 16: Hygienic Earth Energy process[55]

Palladium membranes adapted from conventional hydrogen production facilities are used to extract only the free hydrogen that rises to the top of the reservoir. These membranes are located at the top of the reservoir as shown in Figure 16 to collect the rising hydrogen gas. The "Hygeneration" wells (also an adaption from conventional hydrogen facilities) pump the pure hydrogen up to the well head where it can be used to power the hydrogen generator or processed for export. The "Hygeneration" well can also process valuable products other than hydrogen e.g., oil, syngas, steam, and thermal energy[56]. For example, Proton Technologies has successfully operated the HEE process with dual extraction of hydrogen and oil.

Technology Readiness Level

HEE is currently at TRL 4-6. Proton Technologies' patented technique has been tested successfully in laboratories and in the field with the company aiming to rapidly bring the technology to market. Proton

[53] This increases to ~20.9% if hydrogen compression to 200 bar is included (an increase of ~37.5%).
[54] Hydrogen generator estimates provided by Siemens who have pledged to gradually increase hydrogen capability in gas turbines from 20% in 2020 up to 100% by 2030.
[55] Proton Technologies 2019, Hygienic Earth Energy - Short Animation - Proton Technologies Canada
[56] Proton Technologies 2021, The Proton Process

Technologies is in the process of commercialising the technology and began distributing hydrogen produced via their process in 2021[57]. Initial deployment of HEE is expected to be in the Saskatchewan region in Canada with the successful demonstration of large-scale production expecting to lead to deployment worldwide.

Value Chain Position

The HEE process utilises underground hydrocarbon reservoirs as feedstock and is best suited to regions with existing oil and gas reserves, including offshore sites. The technology is predicted to accept a range of hydrocarbon feedstocks since the process works for both light and heavy hydrocarbon feedstocks (e.g., oil, gas, and coal). As reservoirs deplete the pressure drops results in increased extraction costs. It is estimated that up to 70% of oil remains underground because it is inaccessible or uneconomical to recover[56]. Furthermore, depleted oil and gas reservoirs often become waterlogged once extraction stops. Sites where wells are waterlogged and uneconomic for further extraction are particularly suited to the HEE process. It is also possible to produce hydrogen whilst continuing to extract oil and gas from reservoirs.

Box 1 Potential for further oil recovery from "depleted" fields

Standard oil recovery will rely on natural pressure within the reservoir to bring the oil to the surface and has a recovery rate of approximately 30%. When oil reserves become depleted and natural pressure is no longer sufficient to bring the oil to the surface, secondary recovery techniques can be deployed to increase the reservoir pressure. These typically include injecting water or gas into the reservoir to increase the pressure. Secondary recovery can increase the recovery rate up to 20-40%[58]. Enhanced (or tertiary) oil recovery is a further step that can be utilised to increase oil extraction once secondary recovery fails. This involves reducing the viscosity of the oil by setting targeted areas of the reservoir on fire or heating it with steam. This method is not suitable for all reservoirs but can typically increase the oil recovery rate up to 30-60%[58]. Even with high oil recovery rates, depleted reservoirs will still contain significant quantities of oil that could be utilised for hydrogen production using the HEE process.

The HEE process also benefits from the fact that no CCS infrastructure is required as the CO_2 is stored within the oil / gas reservoir itself as part of the extraction / production process. As only pure hydrogen is extracted from the process, there is no need for further gas refining / processing or expensive CCS equipment and infrastructure. Economies of scale are achievable by siting the technology near to industries where hydrogen offtake will be readily available.

It is expected that depleted oil reservoirs will be the most economic option for deployment as these will have a low value and are often a liability cost for oil companies. The utilisation of existing oil extraction infrastructure can also help to reduce costs of hydrogen production. For example, existing well infrastructure can be utilised. Where hydrogen demand is limited, some regions may also benefit from co-production of hydrogen and oil while transitioning to more hydrogen focused production.

Technology Developers

Proton Technologies has patented their HEE process and are the key stakeholder developing the Technology. Proton Technologies has also partnered with researchers at the University of Calgary who have been influential in testing the technology at lab scale and developing the technology around the "Hygeneration" membrane. Proton Technologies advised that once the process has been optimised, hydrogen can be supplied at a cost of 0.50 US$/kg$H_2$ (compared to 2-3 US$/kg$H_2$ for conventional SMR hydrogen production). This would be cheaper than the price of natural gas in many countries, whilst also being a low carbon fuel source.

[57] Hydrogen Central 2021, Proton Technologies Making Hydrogen From Oilfields, Scaling Way Up
[58] US Department of Energy 2020, Enhanced Oil Recovery

Engagement with Proton Technologies highlighted the ambition of the company and the prospects for accelerating the deployment of the HEE process worldwide. Proton Technologies aim to produce the lowest cost of hydrogen and electricity with the goal of supplying 10% of the world's energy demand by 2040.

Process Data

Process data was collected from literature and stakeholder engagement with Proton Technologies. Data collected for the HEE process is presented in the Appendices (see section 9.2.4). Two cases are presented, one where Proton Technologies' hydrogen turbine is included and the other where the system is powered by electricity from the grid. Where data was unavailable due to the technologies low TRL, assumptions were made that are outlined in the Appendices, Section 9.3. Uncertainties within the process are analysed as sensitivities as part of the techno-economic assessment of the technology.

Whilst this technology shows promise, it has a low TRL of 4-6 and therefore demonstrations are required to validate its technoeconomics. The inclusion of HEE in this report is illustrative of the author's current understanding of the technology but should not be directly compared with the opportunities for SNR and POX

2.3 Conclusions

HEE, POX and SNR technologies were selected for further techno-economic and life-cycle analysis. Both POX and SNR are well established and commercially available technologies for large scale hydrogen production. However, their current deployment for blue hydrogen production, particularly for use with oil-based feedstocks, is still in the early stages of development.

The HEE process is currently at a lower TRL. However, this is being actively developed and has significant potential to produce blue hydrogen from oil-based feedstocks. Proton Technologies claim that the technology is suitable for deployment with a range of feedstocks and is not confined to a specific region or geology. Furthermore, once optimised, Proton Technologies claim that the levelised cost of hydrogen (LCOH) will be approximately 0.50US$/kg$H_2$. This is considerably lower cost than grey hydrogen production currently available; however, because the technology has yet to be demonstrated at scale, it is currently unclear whether the low-cost LCOH can be realised in practice. Future large-scale deployment of HEE technology will be dependent on successful demonstration projects and uptake from stakeholders to install the technology at potential production sites. Achieving the low-cost LCOH claimed will also be dependent on deploying the technology in locations where the cost of hydrogen storage and distribution is minimised. The range of costs associated with the HEE process are presented in the Appendices, Section 9.3.1.

For all three hydrogen production technologies, data availability has been limited due to a combination of the lack of technology deployment for oil-based feedstocks and developing TRL. Assumptions are presented in the Appendices, Section 9.2.

3 Assessment of Hydrogen Demand and Applications

3.1 Overview

Hydrogen demand today is dominated by industrial applications (>99%) such as the production of methanol and ammonia and as a feedstock in refining processes. However, hydrogen is increasingly recognised as a vital component of a global net-zero emission energy future, as recognised in this analysis, and is expected to make inroads in other sectors. This report therefore considers:

- **Industry –** Uses hydrogen as an industrial feedstock (e.g., for oil refining) and / or fuel switching.
- **Heat –** Hydrogen for decarbonisation of the heating system (substitute for natural gas or in blend with methane/biomethane for buildings).
- **Transport –** Different transport modes and use cases are expected to benefit from hydrogen due to the long range and fast refuelling times of fuel cell electric vehicles (FCEVs). This could also include hydrogen in the form of ammonia for maritime applications and synthetic aviation fuels – this is not explored in this report.
- **Power Generation –** Generation of power in converted or dedicated gas turbines as well as stationary fuel cell applications.

This section outlines the current and future global demand for hydrogen based on a literature review of recent studies and projections regarding the likely sectors to switch to hydrogen. This analysis takes place at a regional level in order to identify and account for differences in national and regional strategies in relation to hydrogen. This is supported by three case studies which highlight an advanced perspective on hydrogen in different global regions. A review of current policies is also provided. This supports this project by recognising the supportive policy environment needed for the expansion of low carbon hydrogen production.

3.2 Demand Forecasting Methodology

The methodology listed below was used to develop forecasts of hydrogen demand by global region. This included:

- **Review Energy Demand Forecasts –** Examining current and future energy demand, by sector, based on roadmaps / strategies from government and energy organisations (as given in the Appendices, Section 9.1) gives expected growth in demand for hydrogen from methanol and ammonia out to 2050.
- **Review Regional and National Hydrogen Policy –** Reviewing policy landscape that encourages the uptake of hydrogen across regions and sectors.
- **Review Scenarios for Different Regions –** Considering the balance between different levels of ambitions from literature for hydrogen uptake.
- **Projecting Global Hydrogen Demand**
    - **Regions with Developed Hydrogen Plans –** Using literature and supporting assumptions to forecast hydrogen demand by region and end use case.
    - **Regions with Undeveloped Hydrogen Plans –** Applying a delay to hydrogen uptake of ten-years (as described in the Appendices, Section 9.1) based on undeveloped hydrogen strategies and policy frameworks. This is done based on fuel switching to hydrogen.

In this way the global hydrogen demand forecast out to 2050 is given which favourably compares with literature. Data is presented for 2020 (representing present day), 2030 (when hydrogen demand is predicted to begin accelerating) and 2050 (the upper bound of this analysis). Tabulated results for hydrogen demand forecast by region are presented in the Appendices, Section 9.1.

Regions

Seven distinct regions were chosen for the hydrogen demand analysis and are displayed in Figure 17. These are broken down below by “Developed Hydrogen Strategies” and “Undeveloped Hydrogen Strategies”. This is based on the extent to which there have been regional and national strategies and demand forecasts published for each region.

Developed Hydrogen Strategies

- North America
- Europe
- Asia Pacific

Undeveloped Hydrogen Strategies

- Latin America
- Africa
- Russia & Caspian
- Middle East

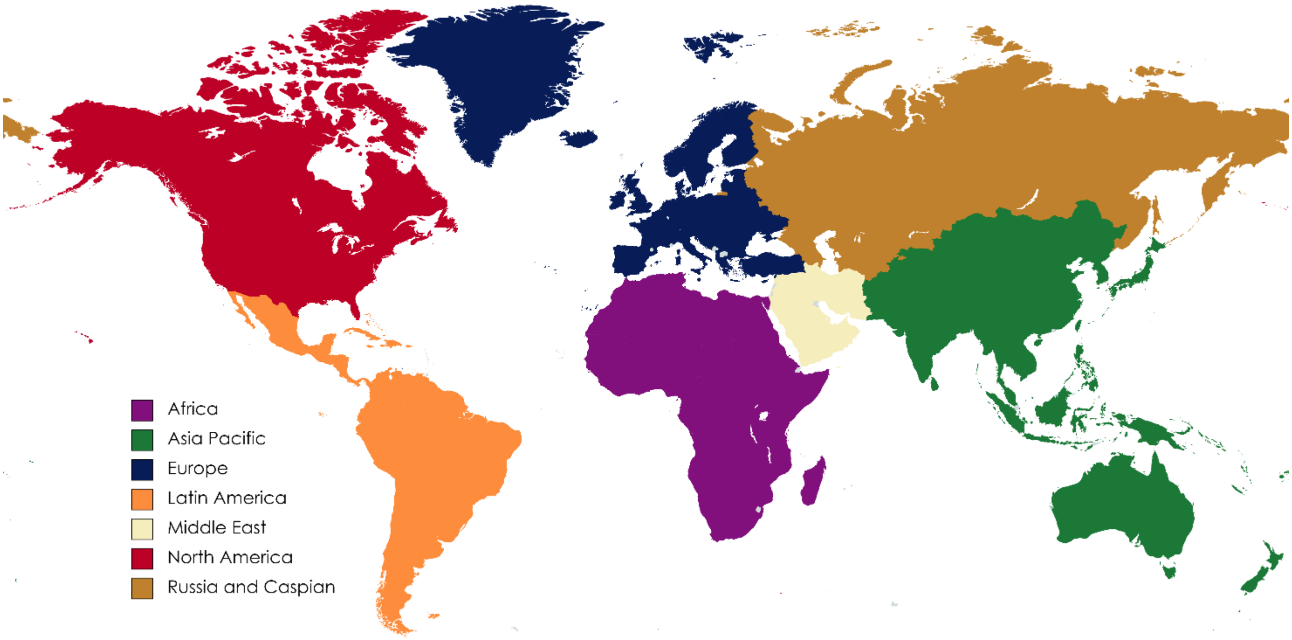

Figure 17: Breakdown of globe by regional demand analysis

Cases Study Selection

Case studies are also provided for the United States of America (USA), the Netherlands and South Korea. These cases are sited in three of the regions where visibility on hydrogen demand trajectories is greatest; North America, Europe, and Asia-Pacific. The three countries have detailed hydrogen roadmaps and are also expected to benefit from both importation and exportation of blue hydrogen.

These case studies:

- Support the overall demand trajectories for our targeted regions.
- Provide an assessment of hydrogen demand at the country level for developed countries.
- Include a commentary on national hydrogen policy and strategy, setting examples for other regions.

3.3 End Use Types

For all regions, the expected hydrogen demand is broken down as far as possible by end use case where information is available from literature.

Industry

Industry constitutes nearly all current global hydrogen demand. This is in the form of both pure hydrogen (i.e., refining and ammonia production) as well as hydrogen blends in the form of syngas (i.e., methanol production and direct reduction of iron (DRI)). Hydrogen is used in the following ways:

- **Direct Reduction of Iron (DRI) –** Hydrogen can replace coal as a reactant to directly reduce iron ore. Hydrogen can be blended and burnt in conjunction with or as a replacement of natural gas or other fuels to provide direct heat for several industrial processes (e.g., metal forming and recycling, brick kilns).

- **Glass Production –** Hydrogen can replace natural gas as a heat source for glass production. This is demonstrated in projects such as HyGear[59].
- **Refining Crude Oil –** Methane reformed hydrogen is currently used to refine crude oil into petrol and diesel via hydro-processing (including hydrotreating and hydrocracking). This removes contaminants such as sulphur, oxygen, nitrogen, and metals[60].
- **Ammonia Production –** Methane reformed hydrogen is combined with nitrogen in the Haber-Bosch process to produce ammonia for fertilisers.
- **Methanol production –** Reacting hydrogen with CO_2 to produce methanol. Methanol can then be used in incumbent industrial processes as well as use in fuel cells, acting as a hydrogen carrier.

This study specifically explores industrial demand in the form of refining, ammonia production, methanol production and other (i.e., DRI and industrial heat). Industrial heat is expected to be an area of high growth. This is particularly the case for large industrial sites from 2030, in simple and high temperature applications such as large boilers. From 2050, hydrogen is also expected to see growth in heating in kilns, furnaces, and dryers[61].

Transport

Transport currently represents a minor fraction of hydrogen demand due to the relative immaturity of hydrogen FCEVs. However, the sector is expected to pick up pace out to 2030 and accelerate further out to 2050, increasing by several orders of magnitude. A range of transport modes are predicted to be hydrogen fuelled in the future as displayed in Figure 18. Transport types are broken down by non-road mobile machinery (NRMM), light duty vehicles (LDVs), heavy duty vehicles (HDVs), rail and other where possible based on data availability. These subsectors are defined as follows:

- **NRMM –** These vehicles are widely deployed having been proven in applications such as forklifts. These applications have a low daily demand and therefore do not feature significantly in this demand analysis.
- **LDVs –** Passenger cars and short distance vehicles are currently dominated by battery electric vehicles. However, longer range vehicles in commercial fleets and vans are expected to grow in number from the mid-2020s, gaining significant market share from 2030.
- **HDVs –** Likewise, trucks and buses are expected to grow in number from the mid-2020s through increased levels of deployment. These are dependent on successful deployments in the early 2020s.
- **Trains –** Trains are expected to be a source of hydrogen demand, with trials taking place across Europe and the USA. The extent to which hydrogen trains are deployed depends on the balance between electrification of railways and replacing diesel trains with hydrogen ones. Hydrogen trains are expected to feature on long-range routes.
- **Other –** For larger vehicles, such as aviation and maritime vessels, hydrogen demand is also expected to come via direct use, as well as in the form of synthetic fuels and carriers such as ammonia. R&D is currently ongoing in this area, focussing on aspects such as powertrain, storage, and refuelling infrastructure requirements. Demonstrations are underway for these vehicle types in the early 2020s, but they are not expected to be responsible for significant demand until after 2030. For example, Germany has introduced a 2% quota for synthetic fuels in aviation demand by 2030[62]. Information on this end use case is more limited; however, Bloomberg estimates that up to 10% of transport hydrogen demand could come from shipping by 2050 in their strong policy scenario[63].

[59] HyGear 2020, Cost Effective Gas Supply
[60] Pall 2020, Hydroprocessing
[61] Element Energy for the CCC 2020, Deep-Decarbonisation Pathways for UK Industry
[62] Baker McKenzie 2021, Sustainable Aviation Fuel (SAF) and the German PtL Roadmap
[63] BloombergNEF 2020, Hydrogen Economy Outlook

Figure 18: Several different transport modes which use hydrogen as a fuel are coming to market

Heat

Domestic heat forms less than 1% of global hydrogen demand as of 2020[1]. This is equal to 0.64 MtH_2/yr, primarily from East Asia[64]. Global hydrogen demand for heat could grow rapidly as countries with national gas grids look to decarbonise, whilst continuing to utilise existing infrastructure. Demand is predicted to increase significantly in Europe, North America, and Asia Pacific regions when / where there is a preference for hydrogen over electrification. Domestic gas boilers and cooking appliances capable of running on a hydrogen-natural gas blend are already available. For countries without pre-existing natural gas infrastructure, stationary fuel cells may provide a suitable solution for providing low carbon heat.

Power

Power forms less than 1% of global hydrogen demand as of 2020[1]. This is equal to 0.67 MtH_2/yr, primarily from East Asia[65]. Electricity generation from hydrogen is possible via:

- **Hydrogen Gas Turbines –** Many natural gas-fired turbines can already run safely with small blends of hydrogen. However, large scale power turbines are currently in development that will run on 100% hydrogen[66].
- **Hydrogen Fuel Cells –** Fuel cells provide a more efficient method for converting hydrogen into electricity, particularly if the heat produced in the chemical reaction is captured[67]. However, unlike gas turbines fuel cells require high purity hydrogen >99.99%. These have a place in electricity generation for grid and remote systems as well as industrial applications for improved plant efficiency and reduced carbon intensity[68].

Figure 19: The world's largest hydrogen fuel cell power plant located in South Korea[69]

The demand forecasts group these end use cases simply under power demand due to the lack of granularity available in literature between these use types. Global hydrogen demand is predicted to grow as countries which rely on natural gas fired power generation look to blend hydrogen into fuel streams to achieve emissions reductions. The use of stationary hydrogen fuel cells is also predicted to grow, particularly to meet heat and power demands in cities. The world's largest hydrogen fuel cell power plant is currently operating in South

[64] Small scale hydrogen demand in heating likely includes the use of hydrogen as Town Gas in Asia Pacific.
[65] This is linked mostly to the use of mixed gases with high hydrogen content from the steel industry, petrochemical plants and refineries, and to the use of by-product pure hydrogen from the chlorine-alkali industry
[66] Siemens Energy 2021, Zero Emission Hydrogen Turbine Center
[67] IEAGHG 2019, Review of Fuel Cell Technologies with CO_2 Capture for the Power Sector
[68] IEAGHG 2020, The Clean Refinery and the Role of Electricity Generation
[69] Doosan 2020, Doosan Fuel Cell Builds World's Largest By-product Hydrogen Fuel Cell Power Plant

Korea as shown in Figure 19. Growth in demand for hydrogen powered buildings is predicted to come initially from East Asia with China and South Korea already in the process of developing hydrogen fuelled cities.

3.4 Regional Assessment

For the first three regions (North America[4, 70, 71], Europe[72, 4] and Asia Pacific[73, 74, 75]) information is given on each demand scenario as well as regional policy developments. For the remaining regions, individual breakdowns by sector are not given due to the similarity in methodology and assumptions. Comments on data certainty is given in all cases. Assumptions and key sources of information are given in the Appendices, Section 9.1.

3.4.1 North America

Industry

The industrial demand for hydrogen is forecast to grow from 48.5Mtoe in 2020 to 90.8Mtoe by 2050. This is primarily driven by a significant increase in the use of hydrogen in sectors outside of the traditional uses for hydrogen (i.e., refining, ammonia production and methanol production) such as hydrogen for industrial grade heat.

- **2020** – Hydrogen demand is dominated by refining, with significant demand also shown for ammonia.
- **2030** – Hydrogen demand in refining continues to form the majority of industrial demand.
- **2050** – Hydrogen demand in industry is expected to increase by approximately 64% from 2030. This is dominated by the increase in demand for "Other Industrial" sectors.

Transport

The demand from transport is highly uncertain by end use case. There are high degrees of uncertainty about the potential for demand from passenger cars due to advances in the battery electric vehicle sector. Focus is instead on heavier duty markets such as buses, trucks, trains and synthetic fuels for aviation and maritime purposes.

- **2020** – There are only a few thousand FCEVs sited in California[76]. Whilst this is one of the largest FCEV fleets globally, this constitutes less than 1/100th of a percentage point of total transport demand.
- **2030** – Hydrogen demand is expected to grow due to uptake of LDVs (i.e., taxis and fleet vehicles) as well as HDVs such as buses and trucks.
- **2050** – Synthetic fuels are a significant demand as are heavy duty vehicles. The demand from rail and NRMM applications have also grown to significant fractions.

Heat and Power

The demand for heat is highly uncertain. This is because some forecasts focus on dedicated hydrogen networks, some consider hydrogen blending up to 20% and others focus on electrification. This is coupled with the current absence of policy direction for decarbonising heat. Literature suggests that hydrogen could replace up to 31% of natural gas by 2030 and 25% of oil in an ambitious US forecast by 2050[70]. When combined with the Canadian forecast[71], the overall demand forecast for hydrogen in the North American region is equivalent to 14.5%.

[70] FCHEA 2020, Road Map to a US Hydrogen Economy
[71] Government of Canada 2020, Hydrogen Strategy for Canada
[72] Fuel Cells and Hydrogen Joint Undertaking 2019, Hydrogen Roadmap Europe
[73] ERIA 2019, Demand and Supply Potential of Hydrogen Energy in East Asia
[74] Deloitte 2019, Australian and Global Hydrogen Demand Growth Scenario Analysis
[75] Korea Hydrogen Study Task Force 2018, Hydrogen Roadmap Korea
[76] CAFCP, FCEV Sales, FCEB & Hydrogen Station Data

- **2020** – Hydrogen demand for both the heat and the power sectors form a negligible part of North American hydrogen demand.
- **2030** – Significant growth is shown in hydrogen demand for heat (6.2 Mtoe) with a minor demand shown for power (1.4Mtoe). This still only represents approximately 1% of expected demand for heat.
- **2050** – Hydrogen demand for heat grows significantly during this period with an increase of 78.7Mtoe. Hydrogen demand for power also grows significantly over this period.

Overall Demand Forecast

Hydrogen demand in the US is expected to grow significantly from 2030 due to the wider deployment of fuel cell electric vehicles and increased penetration of hydrogen in the gas grid. In this time, industry will remain a strong end user whilst power requirements are not expected to be significant. The predicted growth of hydrogen demand in North America from 2020 to 2050 is displayed in Figure 20.

- **2020** – Hydrogen demand is dominated by industry, with minor demand seen for all other sectors.
- **2030** – Industry still forms the majority of hydrogen demand in North America. There is a steady increase in hydrogen demand for both transport and heat. Power remains a minor sector.
- **2050** – Hydrogen demand increases significantly during this period with transport now forming the majority of hydrogen demand. Heat and power demand continues to grow steadily, whilst the industrial demand for hydrogen grows at a slower rate.

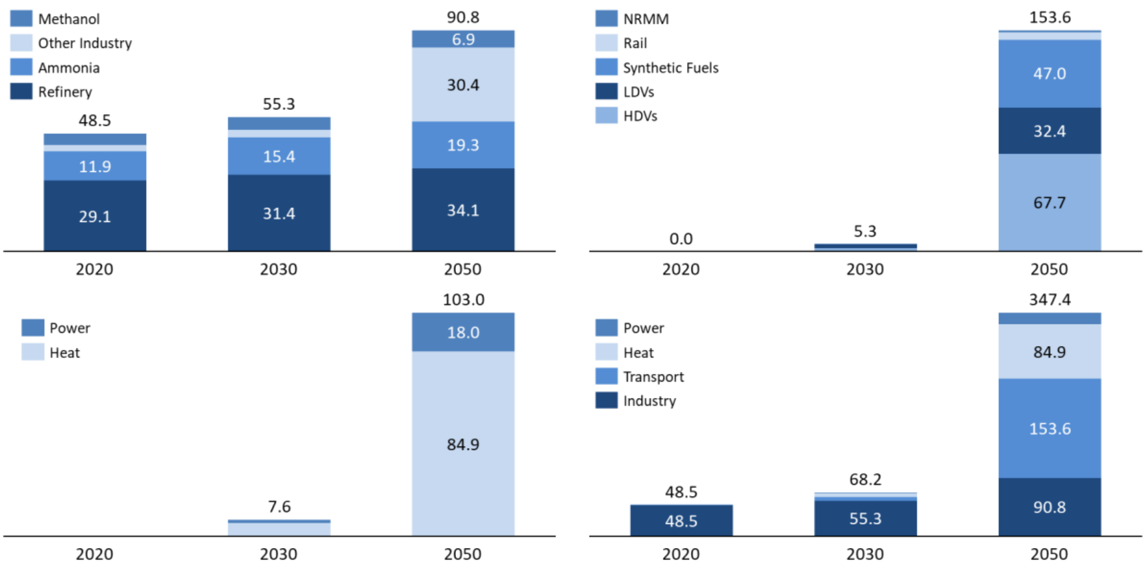

Figure 20: Hydrogen demand by end use case in North America: Industrial (top left), transport (top right), heat and power (bottom left) and Total demand (bottom right) - (Mtoe)

USA Hydrogen Policy

45Q Tax Credit

The 45Q tax credit[77] was enacted in 2018 as a monetary incentive for reducing CO_2 emissions. The incentive was developed to incentivise CCS in energy intensive applications such as blue hydrogen production. Projects can receive \$50/t CO_2 for permanent geological storage and \$35/t CO_2 for CO_2 captured and used such as for enhanced oil recovery (EOR).

Low Carbon Fuels in California

[77] Global CCS Institute 2020, The US Section 45Q Tax Credit for Carbon Oxide Sequestration

The California Low Carbon Fuels Standard (LCFS)[78] is an example of a market incentive that has been successfully implemented to encourage the uptake of low carbon fuels. A declining fuel carbon intensity curve has been developed where credits are awarded for fuels with carbon intensities below the benchmark. Over time, the benchmark carbon intensity will decrease promoting the uptake of fuels such as hydrogen[79].

Hydrogen Earthshot

The US Department of Energy's first Energy Earthshots Initiative, Hydrogen Shot[80], aims to rapidly reduce the cost of low carbon hydrogen by 80% to $1/kgH$_2$ by 2030. Their focus is on markets for hydrogen in steel manufacturing, low carbon ammonia, energy storage and heavy-duty vehicles.

Canada Hydrogen Policy

Hydrogen Strategy for Canada

The government of Canada recently released their hydrogen strategy[71] report in December 2020. This was the result of three years of research and analysis with input from 1,500 experts and stakeholders. The report outlines how Canada aims to diversify its future energy mix over the next 30 years with the goal of developing a thriving hydrogen economy in Canada. Canada has a low carbon intensity electrical grid, abundant fossil fuel reserves and geology well suited for CO_2 storage. These factors can all be leveraged in the future to produce low-cost hydrogen.

Canada is already an established energy exporter for fuels such as natural gas and has significant potential to develop a market for hydrogen export. Canada has ports located on both East and West coasts. This could allow it to unlock export opportunities in the rest of North America, Europe, and East Asia regions. The report identifies the proposed Clean Fuel Standard (CFS) as a key regulation that will help promote investment into the hydrogen economy in Canada. This is a performance-based approach to encourage innovation and the adoption of low carbon technologies throughout Canada. The CFS will establish a credit market where each credit will represent a lifecycle emissions reduction equivalent to 1 tonne of CO_2[81]. The CFS regulation is predicted to come into force in December 2022.

3.4.2 Europe

Industrial Demand

Demand for hydrogen is expected to nearly double in the industrial sector. This is partly driven by growth in existing sectors but is largely due to the growth of other industrial demand such as heat.

- **2020** – Hydrogen demand is dominated by refining and ammonia production (used primarily for the development of fertilisers).
- **2030** – Hydrogen demand in refining is overtaken by growth in ammonia production. Demand in the form of hydrogen for industrial heat and other end use cases also grows considerably.
- **2050** – Demand is now dominated by other end use cases, with ammonia production and refining combined accounting for just over 50% of demand.

Transport

The demand for transport is highly variable by end use case. There are high degrees of uncertainty about the potential for demand from passenger cars due to advances in the battery electric vehicle sector. Focus is instead on heavier duty markets such as buses, trucks, trains and synthetic fuels for aviation and maritime purposes. Information is not given here on aviation or maritime vessels due to the lack of available information.

- **2020** – Hydrogen demand in Europe is isolated to small fleets of buses and taxis.

[78] California Air Resources Board 2020, LCFS Basics
[79] CMS 2020, Hydrogen Law And Regulation in the US
[80] US Office of Energy Efficiency and Renewable Energy, Hydrogen Shot
[81] Government of Canada 2021, What is the clean fuel standard?

- **2030** – Demand for buses is expected to increase due to regional requirements and larger number of taxis and fleet vehicles are also expected.

- **2050** – Hydrogen demand in transport is dominated by demand from HDVs and LDVs. Trains are also significant at this point, constituting 50% of new sales.

Heat and Power

The demand for heat is highly variable. This is because some forecasts focus on dedicated hydrogen networks, some consider hydrogen blending up to 20%[72] and others focus on electrification[82]. This is coupled with the current absence of policy direction for decarbonising heat. Aligning with central forecasts from literature on the demand for hydrogen in heat results in a market share of 8.3%.

- **2020 –** Hydrogen demand for both the heat and the power sector form a negligible part of European hydrogen demand.
- **2030 –** Significant growth is shown in hydrogen demand for heat (8.4Mtoe) with a smaller demand shown for power (3.2Mtoe). This still only represents 1.7% of expected demand for heat.
- **2050 –** Hydrogen demand for both heat and power grows significantly during this period. Hydrogen demand for heat and power forms in 2050 8.3% and 1.2% of total European demand, respectively.

Overall Demand Forecast

Hydrogen demand in Europe is expected to grow significantly from 2030 due to the wider deployment of fuel cell electric vehicles and increased penetration of hydrogen in the gas grid. In this time, industry will remain a strong end user whilst power requirements are not expected to be significant. The predicted growth of hydrogen demand in Europe from 2020 to 2050 is displayed in Figure 21.

- **2020 –** Hydrogen demand is dominated by industry, with minor demand seen for all other sectors.
- **2030 –** Heat, transport and power sectors continue to grow, but the market is still dominated by hydrogen for industry.
- **2050 –** By 2050, hydrogen from transport and industry are nearly equal due to strong growth in the transport sector.

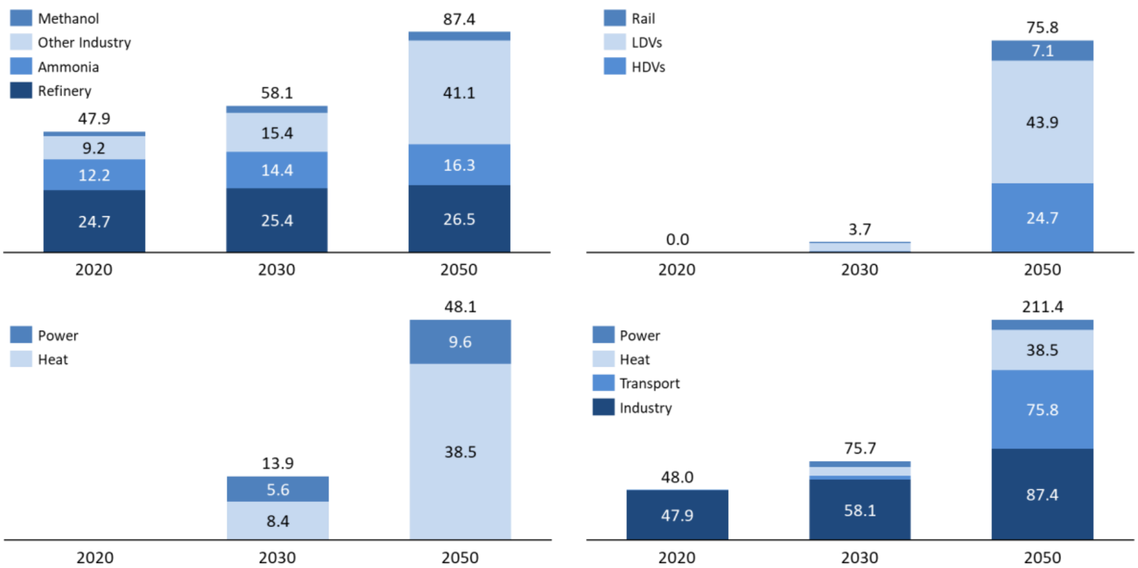

Figure 21: Hydrogen demand by end use case in Europe: Industrial (top left), transport (top right), heat and power (bottom left) and Total demand (bottom right) - (Mtoe)

[82] Electrification Alliance, An ambitious Fit for 55 package is crucial to decarbonise Europe's heating and colling sector and make it fit for 2050

Europe Hydrogen Policy

Renewable Energy Directive (RED) II

In December 2018, the RED II (a revised version of the original RED) came into force. This raised the overall EU target for consumption of renewable energy sources to 32% by 2030. A separate target for the transportation sector requires a minimum of 14% of energy consumed by road and rail transport to be supplied from renewable sources[83].

European Commission – A Hydrogen Strategy for a Climate Neutral Europe

The European Commission published its Hydrogen Strategy in July 2020[84]. Three key time periods are identified with the following targets:

- **2020 – 2024:** a minimum of 6GW of electrolysers will be installed producing up to 1 million tonnes of renewable hydrogen.
- **2025 – 2030:** a minimum of 40GW of electrolysers will be installed producing up to 10 million tonnes of renewable hydrogen.
- **2030 – 2050:** renewable hydrogen should reach maturity and be deployed at scale across all hard to decarbonise sectors.

The report identifies renewable hydrogen as a priority however recognises that other forms of low carbon hydrogen production will be necessary in the short term. This transition is supported by the EU's Fit for 55 package[85], which introduces thirteen (non-hydrogen specific) initiatives to reduce greenhouse gas emissions by 55% by 2030 relative to 1990.

This presents a significant opportunity for blue hydrogen production including from oil-based feedstocks to meet increasing hydrogen demand in Europe. However, it also poses risks, as green hydrogen is likely to be the favoured hydrogen production technology in the long term.

3.4.3 Asia Pacific

Industrial Demand

Industrial energy demand is evenly divided between the listed use cases in 2020. As for the other demand regions, the demand for other industrial applications significantly increases from 2030 due to more fuel switching activities.

- **2020 –** Hydrogen demand is fairly balanced between the end use sectors.
- **2030 –** There is moderate growth for refinery, ammonia, and methanol demand. However, most growth comes from other industrial sources such as the demand for industrial grade heating at a compound annual growth rate (CAGR) of 2.3%.
- **2050 –** Hydrogen demand more than doubles between 2030 and 2050. The growth rate for other end use cases drives this demand.

Transport

Hydrogen demand for transport is expected to vary significantly by country within the Asia Pacific region. However, demand is expected to be largely driven by HDVs and LDVs. This is in part due to the number of regional manufacturers who are producing FCEVs.

- **2020** – Early deployments of buses and passenger cars across the region result in some transportation demand but this is a negligible fraction of transport energy requirement.

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[83] European Commission 2018, Renewable Energy – Recast to 2030 (RED II)
[84] European Commission 2020, Powering a climate-neutral economy
[85] PtX Hub, The Fit for 55 Package: Key Points for Green Hydrogen and PtX

- **2030** – Out to 2030, most of the growth comes in the form of LDVs in taxi fleets and commercial vehicles. Trucks increasingly come to market.

- **2050** – The hydrogen market is dominated by demand from heavy duty vehicles with some demand from markets such as NRMM, rail and shipping. LDVs also constitute a large fraction.

Heat and Power

The demand for heat and power is highly variable due to the range of approaches to hydrogen in the Asia Pacific region. The increase in demand for power is noticeable, compared to other regions, reaching the same orders of magnitude as for heat.

- **2020** – Hydrogen Demand for both the heat and the power sector form a very small fraction of hydrogen demand in East Asia.
- **2030** – Significant growth is shown in hydrogen demand for power (41.7Mtoe) with a minor growth in demand shown for heat (5.7Mtoe).
- **2050** – Hydrogen demand for both heat and power grow significantly during this period. Hydrogen demand for heat and power in 2050 forms 9.2% and 3.3% of total demand, respectively.

Overall Demand Forecast

Hydrogen demand is expected to grow significantly from 2030 due to the wider deployment of fuel cells in the transportation and power generation sectors in East Asia. In this time, hydrogen demand in industry will continue to grow steadily whilst there will be a rapid increase in hydrogen demand in the transportation, power, and heat sectors from 2030 onwards. The predicted growth of hydrogen demand in Asia Pacific from 2020 to 2050 is displayed in Figure 22.

- **2020** – Hydrogen demand is dominated by industry, with minor demand seen for all other sectors.

- **2020 - 2030** – Industry still accounts for the majority of hydrogen demand in the Asia Pacific region. There is a steady increase in hydrogen demand in both the transport and heat sector, with overall hydrogen demand almost doubling during this period.

- **2030 - 2050** – Hydrogen demand increases significantly during this period with transport demand approximately matching that of industry. Heat and power demand is expected to grow significantly during this period.

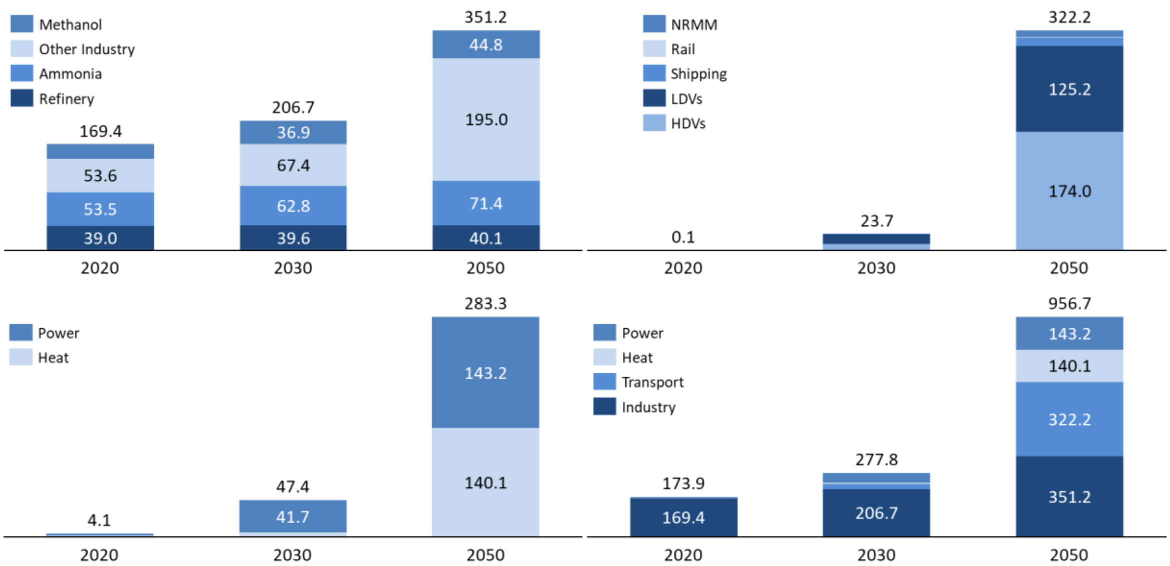

Figure 22: Hydrogen demand by end use case in Asia Pacific: Industrial (top left), transport (top right), heat and power (bottom left) and Total demand (bottom right) - (Mtoe)

Asia Pacific Hydrogen Policy

Unlike Europe and North America, the Asia Pacific region does not have a well-defined roadmap for the future of hydrogen deployment. However, hydrogen strategies for individual countries and regions, where the literature surrounding hydrogen deployment is more advanced, have been analysed.

Hydrogen Roadmap South Korea

The South Korean government has identified hydrogen as a new growth engine for the country and has pledged to develop a hydrogen economy[75]. Currently, the government is focusing on developing a domestic hydrogen market. At present, approximately 50% of Hydrogen Refuelling Stations (HRS) are subsidised by the government. The Korean government introduced the Renewable Portfolio Standard (RPS) in 2012 which mandates large power producers to meet a minimum portion of their generation from new and renewable technologies[86]. This includes hydrogen fuel cell power generation. South Korea is also considering the import of hydrogen from overseas and aims to have 70% of hydrogen demand met from low carbon methods of hydrogen production by 2040. This is likely to include a mix of both blue and green hydrogen production methods, however, grey hydrogen will likely make up the remainder of the countries demand still representing a significant proportion of overall demand.

China

The 'Ten Cities' programme[74,87] used to launch battery electric vehicles will be replicated for hydrogen transport in cities including Beijing and Shanghai. Wuhan will be developed into China's first hydrogen city with an aim for 300 HRS by 2025. The Chinese government recommitted to the 2015 target of 1 million FCEVs and 1,000 HRS by 2030. FCEVs (and battery EV's) are also exempted from vehicle/vessel tax. It is estimated that China is investing approximately US$15 billion in hydrogen research and development (R&D) driven largely by air quality and decarbonisation targets.

Japan

Japan released its Basic Hydrogen Strategy in December 2017[88]. This included an aim of importing 300,000 tonnes of hydrogen per year by 2030. Japan H2 Mobility was launched with a target of developing 80 HRS by 2021. The 2020 Olympics was to be fuelled by hydrogen with the Tokyo Metropolitan Government originally reserving US$350 million in a fund to subsidise FCEVs and HRS in the lead up to the games[89]. Although the Olympic games were postponed to 2021, the Tokyo Metropolitan Government are pressing ahead with its original plans for hydrogen transport deployment[90].

Australia

Australia is well positioned to become a significant hydrogen exporter, particularly to countries in East Asia where demand is predicted to increase significantly due to rising FCEV deployment. Australia benefits from abundant national resources for both blue and green hydrogen production. Australia's National Hydrogen Strategy includes a prospective study identifying the most suitable regions for blue hydrogen production based on the location of feedstock and geological CO_2 storage[91]. It is also well positioned geographically and already has substantial experience as an energy exporting country[74].

3.4.4 Undeveloped Hydrogen Strategy Regions

Hydrogen demand forecasts for Latin America, Africa, Middle East, and Russia & Caspian are based on fuel switching and using demand trajectories from North America, Europe and Asia Pacific. A ten-year lag is applied to uptake to represent the slower uptake of hydrogen in these regions due to the less developed hydrogen

[86] Edito Energie and Ifri 2018, South Korea's Hydrogen Strategy and Industrial Perspectives
[87] ICCT 2020, Ten cities, thousand fuel cell vehicles? China is sketching a roadmap for hydrogen vehicles
[88] METI 2017, Basic Hydrogen Strategy Determined
[89] Bloomberg 2016, Tokyo's Olympic Bet on Hydrogen Power
[90] Nature Portfolio 2020, Leading Tokyo's starring role in the hydrogen revolution
[91] COAG Energy Council 2019, Australia's National Hydrogen Strategy

strategies. The predicted growth of hydrogen demand in regions with undeveloped hydrogen strategies is displayed by end use case in Figure 23.

The assumptions for these regions are presented in the Appendices, Section 9.1.

Industry

Industrial hydrogen demand is expected to nearly double between 2020 and 2050. This is led by uptake in Africa (143% growth), the Middle East (99% growth), Russia & Caspian (95% growth) and finally Latin America (73% growth). As shown previously for regions with developed hydrogen strategies, this is largely due to the increased use of hydrogen in hard to decarbonise industrial sectors such as DRI, glass production and the supply of industrial heat and the continued growth in sectors such as refining, methanol production and ammonia production.

Transport

Even in 2030, the hydrogen transport market is not expected to be significant. In previously explored regions, the market only reaches comparable size with other demand areas (e.g., heat and power) around 2030. For these regions, therefore, it is estimated that market growth will accelerate from 2040. In 2050, the demand for hydrogen in transport becomes comparable with demand from the industrial sector representing 21% (Russia and Caspian), 40% (Africa), 29% (Middle East) and 42% (Latin America) of total hydrogen demand of the analysed regions respectively.

Heat and Power

Hydrogen demand for heat is negligible in 2020 however it is expected to follow a similar trajectory to transport. Although demand in 2030 is small, significant growth is expected over the subsequent two decades, reaching approximately half the size of the industrial and transport hydrogen demand by 2050. For power, demand remains half that for heat and is not expected to be significant until 2050.

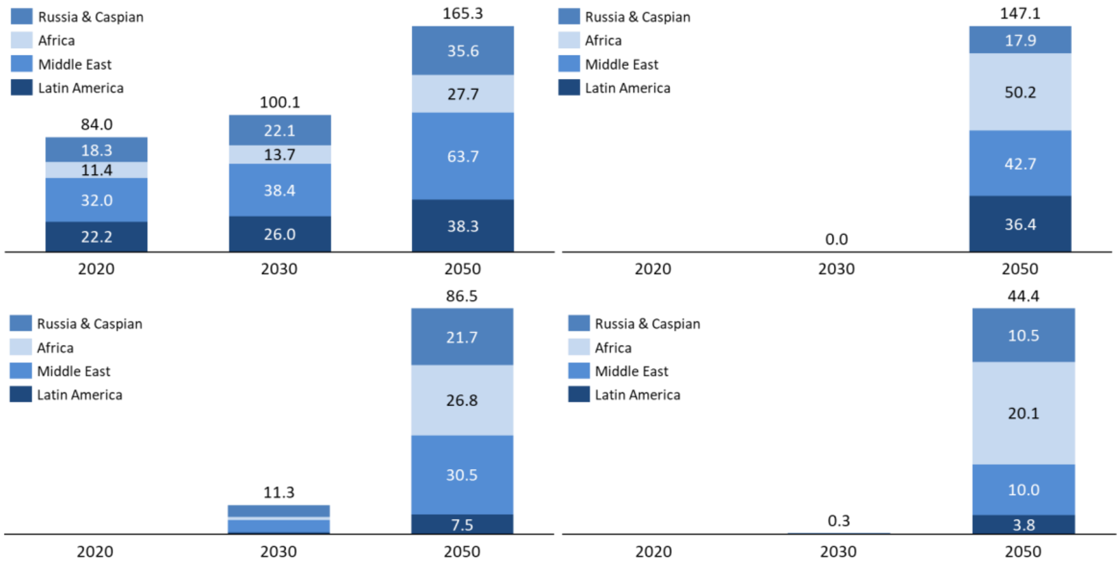

Figure 23: Hydrogen demand by end use case for regions with undeveloped hydrogen strategies: Industrial (top left), transport (top right), heat (bottom left) and power (bottom right) - (Mtoe)

Hydrogen Policy

Latin America

Currently, hydrogen demand in Latin America is used mainly as a feedstock in refineries and the chemical industry. However, Latin America possesses abundant renewable and fossil fuel energy sources that could be utilised for hydrogen production[92]. Many countries have identified hydrogen as a means of decarbonizing heavy-duty transport whilst also looking to benefit from international export opportunities.

[92] IEA 2020, Latin America's hydrogen opportunity: from national strategies to regional cooperation

Brazil

The addition of hydrogen into the energy mix is actively being considered by the Brazilian Hydrogen Association and a range of industry stakeholders. Two demonstration projects are currently underway funded by the Federal Fund for R&D projects in the electrical energy sector. Two hydrogen-based energy storage pilot plants are being developed with investments of €8.0M and €11.9M, respectively[93]. The larger project will include a 50Nm^3/h electrolyser, 900Nm^3 hydrogen storage tank at pressure of 27 bar and a 300kW fuel cell for reconverting hydrogen back to electricity.

Chile

58,500 tonnes of hydrogen are produced in Chile per year, 98% of which is used in refineries[94]. The hydrogen market is at an early stage primarily due to technical barriers, an underdeveloped legal framework and lack of financial support mechanisms. However, the Ministry of Energy published an ambitious "National Green Hydrogen Strategy" in November 2020 which aims to producing the worlds cheapest green hydrogen by 2030 and developing a future export market[95]. Hydrogen fuelled mining vehicles have been identified as a key area for reducing emissions in the country's copper mines.

Mexico

Mexico's "National Hydrogen Plan" was published in 2016[96]. Hydrogen production in Mexico is dominated by state owned oil and gas companies in by-product production processes such a catalytic naphtha reforming. Clean Energy Certificates provide financial benefits for renewable energy generation. Hydrogen produced from renewable sources could benefit from this incentive if the produced hydrogen is used for energy generation.

Middle East

Hydrogen technology is in its early stages of development in the Middle East. As an oil and gas producing region, the Middle East may be able to take advantage of existing infrastructure that can be repurposed for hydrogen production, transportation, and export. At present, there is no specific regulatory framework for the licensing and implementation of hydrogen projects in the Middle East which is currently a barrier to uptake of hydrogen technology in the region. Some hydrogen strategies are emerging, such as the report for the Gulf Cooperation Council[97].

Saudi Arabia

In July 2020, Air Products announced plans to build the world's largest green hydrogen plant in Saudi Arabia, producing 650 tonnes-H_2/day[98]. The project is due to be operational in 2025 in Neom, a new mega-city developed on the borders between Egypt and Jordan. Saudi Aramco and Air Products developed Saudi Arabia's first hydrogen refueling station that became operational in 2019[99].

UAE

Air Liquide recently undertook a study in collaboration with Al Futtaim, Toyota and Khalifa University which considered strategies for developing the hydrogen industry in the United Arab Emirates (UAE)[100]. This demonstrated that hydrogen fuelled transportation could become a major sector in the future. Policymakers in the UAE have identified CO_2-free hydrogen of particular interest from a climate policy point of view. In February 2019, the Dubai Electricity and Water Authority announced plans for the first solar power electrolysis facility that is predicted to be operational by 2022[101]. The Abu Dhabi Police has announced plans to convert its vehicle fleet to FCEVs by 2050, with the Toyota Mirai tested as a potential fleet vehicle by the Dubai Taxi corporation.

93 IPHE 2021, Brazil
94 CMS 2021, Chile
95 Government of Chile 2020, National Green Hydrogen Strategy
96 CMS 2021, Mexico
97 Qamar Energy, 2020, Hydrogen in the GCC
98 Air Products 2020, Air Products, ACWA Power and NEOM Sign Agreement for $5 Billion Production Facility in NEOM Powered by Renewable Energy for Production and Export of Green Hydrogen to Global Markets
99 Air Products 2019, Saudi Aramco and Air Products Inaugurate Saudi Arabia's First Hydrogen Fueling Station
100 Air Liquide 2018, Hydrogen Mobility
101 Expo Dubai UAE 2020, Future energy: new facility demonstrates the potential of green hydrogen

With population density centred in the cities of Abu Dhabi and Dubai, Air Liquide has predicted that 12 hydrogen refuelling stations would be sufficient to cover most of the nation's hydrogen fuel demand.

Russia & Caspian

Hydrogen development in the Russia and Caspian region is currently in its infancy with the region still heavily reliant on fossil fuels. However, interest is growing in Russia to develop the country into a global exporter of hydrogen.

Russia

Hydrogen is produced in Russia primarily for use in oil refinery, steel and chemical industries with hydrogen often produced on-site. There are currently no dedicated state support measures or incentives relating to the hydrogen industry in Russia. In August 2019, the Russian Ministry of Energy met with officials and representatives from state owned companies Gazprom, Rostech and Rosatom to discuss the future of hydrogen. It was decided that a state program of hydrogen energy would be developed alongside a hydrogen roadmap for the future. A draft Road Map was recently submitted to the Russian Government stating Gazprom and Rosatom will launch pilot hydrogen plants by 2024. Russia's hydrogen strategy launched in 2021 sees Russia as a world leader in the production and export of hydrogen, targeting 20% of the global market by 2030[102]. Testing of the Russia's first hydrogen fueled tram started in St. Petersburg in 2019 with plans for hydrogen fueled train tests by 2024[103].

Russia as a Hydrogen Exporter

A report published by EnergyNet in 2019 highlighted that the export of hydrogen to the global market should be a top priority for the Russian economy. An ambitious goal of making up 15% of the global export market by 2030 was stated[104]. There is however potential that Russia may face obstacles of a political nature when trying to export hydrogen, in a similar manner to those it has experienced exporting gas.

Africa

Africa benefits from abundant renewable and large natural gas resources giving the opportunity to start producing both blue and green H_2. Countries such as Egypt are well positioned to supply hydrogen to key markets in Europe where hydrogen demand is forecast to increase significantly.

Future Uses of Hydrogen in Africa

Stationary fuel cells linked to renewable hydrogen production via electrolysis could provide an alternative to battery storage as a method of providing off-grid electricity to remote communities[4]. Hydrogen could form a key component of microgrids in the future. The use of hydrogen fuel cell vehicles in the mining sector has been identified as a potential option for decarbonising heavy-duty machinery used in the mining sector in Africa[105]. There has currently been no clear statement outlining the preference of hydrogen production technologies that will be developed in Africa. This suggests that there are opportunities to develop blue hydrogen production facilities to meet future demand.

South Africa

The South African government has earmarked approximately US$33M for the solar research infrastructure roadmap which includes the production of green hydrogen via electrolysis[106]. The President also signed into law the Carbon Tax Act which came into effect in June 2019 where companies will pay approximately US$7.8 per ton CO_2-eq. This has the potential to help encourage the uptake of both green and blue hydrogen. With significant natural gas and coal reserves, blue hydrogen production could be utilised to kickstart the hydrogen economy in South Africa. Many of the gas fields off the coast of South Africa are depleted and could be repurposed for CO_2 storage. In 2018, 300 stationary fuel cells were installed in South Africa to provide back-up power for telecoms stations[4].

[102] S&P Global 2021, GLOBAL GAS: Russia bets on hydrogen future as pressure for cleaner fuel mounts
[103] CMS 2021, Russia
[104] OSW 2020, Russia's hydrogen strategy: a work in progress
[105] Electrek 2020, World's largest EV — a mining truck — will be hydrogen-powered
[106] IPHE 2021, Republic of South Africa

3.5 Global Hydrogen Demand Assessment

3.5.1 Global Demand Forecast by Region

Hydrogen demand largely follows the distribution of total energy demand by region, according to the IEA's "World Energy Outlook 2020 – Stated Policies Scenario"[107]. However, the relative demand for hydrogen from Europe, North America and Asia Pacific is greater than their respective relative demand for all energy in the IEA's "World Energy Outlook 2020 – Stated Policies Scenario"[107]. This is due to their advanced position in developing a hydrogen economy and the increased demand for hydrogen in their respective transport, heat, and power sectors.

Asia Pacific is expected to have a demand of nearly 49% of the global hydrogen supply by 2050, led primarily from strong demand in India and China. North America and Europe are responsible for 18% and 11% respectively by 2050. These are the two other large global markets for hydrogen demand.

The remaining 22% of global hydrogen demand is split between Russia & Caspian, Latin America, Africa, and the Middle East. However, their demand for hydrogen is expected to become more significant beyond 2050 due to their relative delay in establishing their hydrogen economies.

Emerging and oil-rich regions with the capability to produce low-cost blue hydrogen from oil-based feedstocks are not expected to benefit from large local markets in 2020 and 2030. Instead, their focus should be on exporting hydrogen to those regions with more developed hydrogen markets such as Europe, North America, and Asia Pacific.

In the longer term, hydrogen demand from local markets in these emerging regions could grow exponentially. They would then benefit from at-scale production of blue hydrogen derived from oil and oil-based based products. These production pathways will still have to compete with natural gas based blue hydrogen production as well as emerging green hydrogen production technologies. In the long term, green hydrogen production in regions with access to low-cost renewable electricity from solar and wind (such as Australia, Middle East, and North Africa) are expected to become increasingly competitive.

3.5.2 Global Demand by End use Case

The global demand for hydrogen by sector mirrors the individual regional demand. Demand is expected to increase by 51% between 2020 and 2030, at a CAGR of 4.2%. However, the largest increase comes in the subsequent two decades where the hydrogen demand increases by 267%, at a CAGR of 6.7%.

- The demand is still led by the global industrial sector. However, the relative demand decreases from 99% in 2020 to 35% by 2050.
- This is due to significant increases in both hydrogen for heat and hydrogen mobility. These sectors constitute 18% and 36% of global demand respectively by 2050.
- The remaining demand for power gains some significance by 2050, account for 11% of global supply.

3.5.3 Global Demand Comparison

Based on these central forecasts and analysis of literature, it is estimated that the global demand for hydrogen in 2050 will be 1,959Mtoe. This is equivalent to 578MtH_2/yr. The global demand forecast is displayed by region and end use case in Figure 24. This compares favourably with estimates from literature displayed by Figure 25.

[107] IEA 2020, World Energy Outlook 2020; whilst this scenario does not consider hydrogen, the trajectories in total energy demand are used to predict opportunities through fuel switching. There are many other scenarios, with varying degrees of oil and oil-based product consumption; this study does not explore these different pathways.

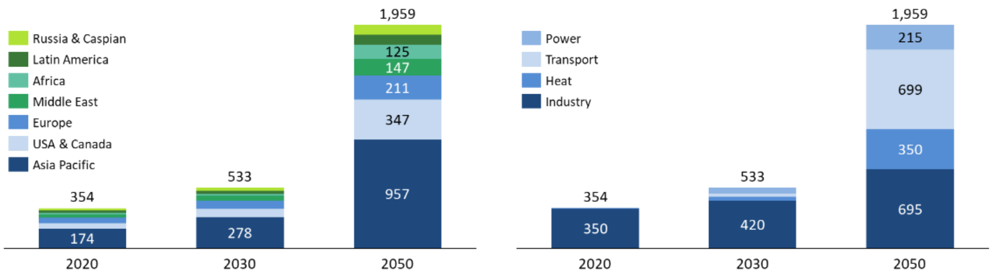

Figure 24: Global hydrogen demand forecast by region (left) and end use case (right) - (Mtoe)

- **Hydrogen Council** – The Hydrogen Council[108] estimates a total global demand of approximately 540MtH_2/yr by 2050. Of this demand, approximately 55% is expected to be green and 45% is expected to be blue. These replace the current demand for grey hydrogen by 2040.
- **Bloomberg** – The Strong Policy scenario in Bloomberg's[63] forecast for global hydrogen demand is 696MtH_2/yr in 2050. This aligns with this study's estimate for hydrogen by this milestone. It is interesting to note that Bloomberg predicts that the theoretical maximum for hydrogen is 1370MtH_2/yr by 2050. This is 2.37 times greater than this study's current forecast. Likewise, if hydrogen is not supported by suitable policy frameworks, then this demand may only reach 187MtH_2/yr. This is only 1.79 times the demand for hydrogen in 2020.
- **IEA** – The IEA's Net Zero by 2050 report[109] estimates a total hydrogen demand of 530MtH_2/yr by 2050. Around 25% of this is expected to be produced in industrial facilities with the remaining supply as merchant hydrogen (that sold from one company to others). Hydrogen fuels (including ammonia and synthetic fuels) are expected to account for 30% of this demand. Electrolytic hydrogen accounts for 60% of this supply.
- **Wood Mackenzie** – Wood Mackenzie[110] estimates that there could be a market for 1,400Mtoe or 413MtH_2/yr by 2050 under a 2-degree Celsius scenario. This would meet 10% of the global energy demand. Of this, the majority is expected to be supplied by electrolysis.

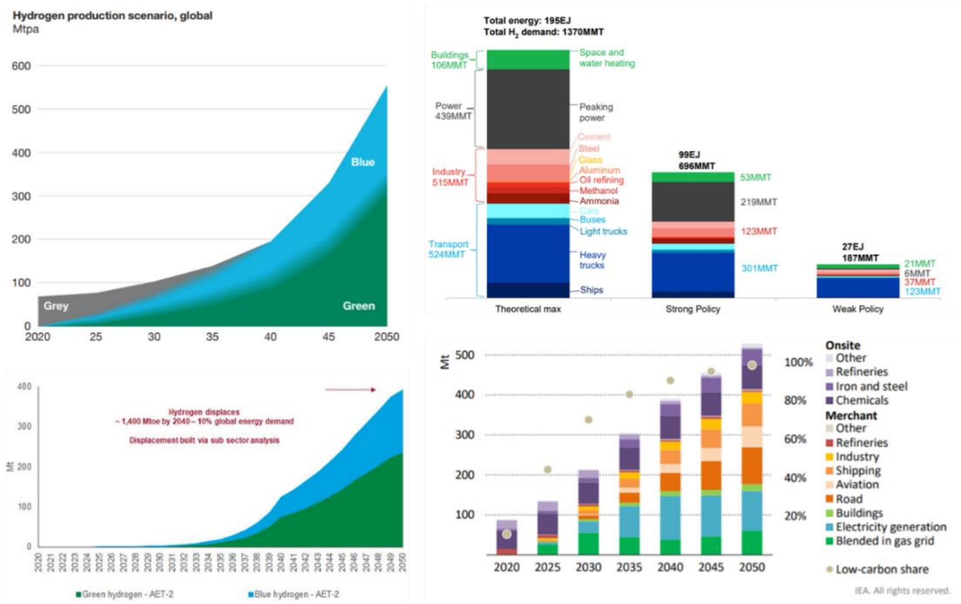

Figure 25: Global hydrogen demand forecasts from (clockwise from top left) the Hydrogen Council, Bloomberg, IEA Net Zero by 2050 and Wood Mackenzie.

108 Hydrogen Council 2021, Hydrogen decarbonization pathways
109 IEA, 2021, Net Zero by 2050 – A Roadmap for the Global Energy Sector
110 Wood Mackenzie 2020, Green Hydrogen: A Pillar Of Decarbonization?

These forecasts found in literature are all a comparable magnitude, with similar perspectives on the proportions that blue and green hydrogen will make up of total demand. However, there are major uncertainties that make it very challenging to accurately predict the future balance of blue and green based hydrogen production technologies. This will be dependent on the successful deployment of emerging technologies and regional policies favouring certain types of technologies. Data points from Bloomberg's Strong Policy scenario were used to support this study's hydrogen demand analysis. Its contribution is outlined in the Appendices, Section 9.1. The Hydrogen Council and Wood Mackenzie forecast were used purely for comparison purposes.

3.6 Case Study Regions

Case study countries are provided for three of the regions where visibility on hydrogen demand trajectories is greatest; North America, Europe, and Asia-Pacific. The three countries have detailed hydrogen roadmaps and are also expected to benefit from both importation and exportation of blue hydrogen. The methodology for selecting these countries is outlined in Section 3.2. These countries are the offtakers for hydrogen production in the 2020s in the scenarios explored in Section 5.

3.6.1 USA

Hydrogen Demand Forecast

The hydrogen demand forecast for the USA by end use case is displayed by Figure 26.

- **2020** – Hydrogen demand is dominated by industry with negligible demands for all other sectors.
- **2030** – Hydrogen remains dominated by industry. However, there is significant growth in the heat sector that now makes up 11.0 Mtoe. Industry demand continues to grow, whilst a small demand for transport also emerges.
- **2050** – Hydrogen demand in the transport sector is predicted to grow rapidly and nearly double industrial demand by 2050. Hydrogen for heat now constitutes 49.1Mtoe whilst power emerges as a small demand source of 13.9Mtoe.

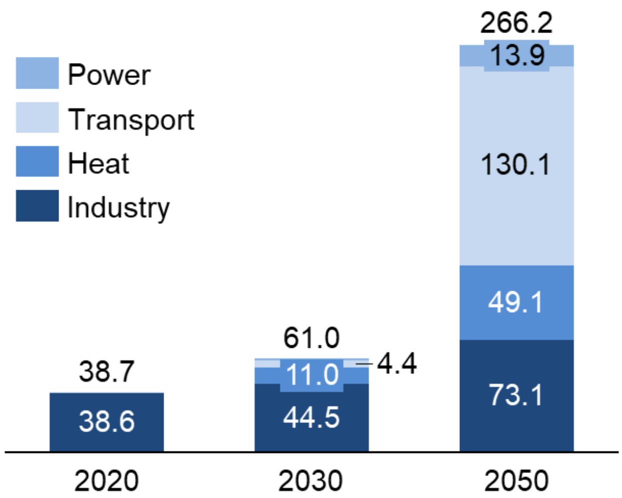

Figure 26: USA hydrogen demand forecast by end use case (Mtoe)

USA Hydrogen Policy

It is predicted that hydrogen in the USA could produce revenues of approximately $130-170 billion per year by 2050[111]. The USA has the potential to produce hydrogen via electrolysis from renewable sources such as solar and wind whilst it also has an abundant supply of low-cost natural gas for blue hydrogen production. The USA has significant variation between each state and region for how hydrogen infrastructure should be deployed in

[111] CMS 2021, Hydrogen Law and Regulation in the US

the future. Many current hydrogen projects relate to the transport sector. The USA currently has over 8,000 FCEVs on the road, more than any other country[112]. California is leading the way for hydrogen fuelled mobility with 31 hydrogen refuelling stations currently operational. The USA has a large long-haul trucking industry that has been identified as a sector that will be suitable for fuel cell application and an area of significant future demand. The USA has also introduced a monetary incentive for reducing CO_2 emissions with the 45Q Tax Credit, introduced previously in Section 3.4.

Operating and Emerging Hydrogen Projects

Port Arthur, Texas

Two SMR hydrogen production plants with integrated CCS were developed for blue hydrogen production by Air Products in Port Arthur, Texas[43]. The plants were commissioned in 2013. CO_2 is captured from the process gas stream via a Vacuum Swing Adsorption (VSA) system. Compression and drying processes subsequently concentrate the CO_2 stream to >97% purity. Compressed CO_2 is then transported via the Denbury pipeline to enhanced oil recovery projects in Texas where the CO_2 is used to extract additional oil/gas, whilst also being stored underground.

Low Carbon Gasification

SGH2 (a private energy company) will develop the world's largest green hydrogen production facility in the city of Lancaster, California[113]. The facility will utilise recycled mixed paper waste as feedstock to produce low carbon hydrogen via gasification. The facility will be able to produce up to 11 tonnes of hydrogen per day. This will primarily supply hydrogen refuelling stations located in California. Construction will begin in 2021, with the plant expected to be operational by 2023. Hydrogen produced using this technology is predicted to be immediately cost competitive with grey hydrogen production as displayed by Figure 27.

	HYDROGEN TYPES	CARBON INTENSITY (KG/H2)	PRODUCTION $ (KG/H2)
GREEN HYDROGEN	SGH2 Greener Than Green Hydrogen	-188 KgCO2eq/MJ (avoiding 29 kg of CO2 per kg of H2)	$2
	Green Hydrogen (Electrolysis)	0 kgCO2eq/MJ	$10-$13
HYDROGEN FROM FOSSIL FUELS	Gray Hydrogen from NatGas	+12 kg CO2	$2-$6 *(costs of natural gas)*
	Brown Hydrogen from Gasification of Coal	+20 kg CO2	$2-$3
BLUE HYDROGEN WITH CARBON CAPTURE & SEQUESTRATION	Gray Hydrogen	+12 kg CO2 (carbon captured)	$6-$10
	Brown Hydrogen	+20 kg CO2 (carbon captured)	$6-$7

Figure 27: Comparison of hydrogen production options with SGH2 technology[113]

Air Liquide Hydrogen Plant, North Las Vegas

Air Liquide aims to begin operating a new hydrogen production plant in 2022. This will supply hydrogen to the mobility market on the US West Coast. Air Liquide will use a steam methane process which uses biogas, landfill gas and waste-water treatment gas. This will reduce the carbon intensity of the produced hydrogen[114].

Summary

The USA is the top oil producing country in the world with 19.5 million barrels per day of production in 2019[115]. There is significant potential for oil-based blue hydrogen production in the USA as the country benefits from both abundant feedstocks and large geological CO_2 storage capacity in both saline aquifers and depleted oil

[112] IEA 2020, Advanced Fuel Cells Technology Collaboration Programme
[113] SG H_2 Energy 2021, World's Largest Green Hydrogen Project to Launch in California
[114] Fuel Cell Works, 2021, New Hydrogen Fuel plant in Nevada Launches Greater Role for Hydrogen Fuel Cell Vehicles in Zero-Emission Transportation Mix
[115] Investopedia 2021, The World's Top Oil Producers

and gas fields. Hydrogen demand is currently provided from the industrial sector, whilst the uptake of FCEV's is forecast to significantly increase the demand for hydrogen in the transport sector over the next 30 years. Large scale blue hydrogen projects have been demonstrated successfully whilst the Low Carbon Fuel Standard and 45Q Tax Credit are examples of incentives that have been successfully deployed to further encourage the uptake of hydrogen.

3.6.2 The Netherlands

Hydrogen Demand Forecast

The hydrogen demand forecast for the Netherlands by end use case is displayed in Figure 28.

- **2020** – Hydrogen demand is dominated by industry, with minor demand from both heat and transport. Hydrogen demand from the power sector is negligible.
- **2030** – Hydrogen demand more than doubles in the 2020 to 2030 period but is still dominated by industry. Demand from industry and heat grows steadily, whilst transport and power remain small sectors for demand.
- **2050** – Hydrogen demand in industry experiences the greatest absolute increase, but growth is greatest in power and heat.

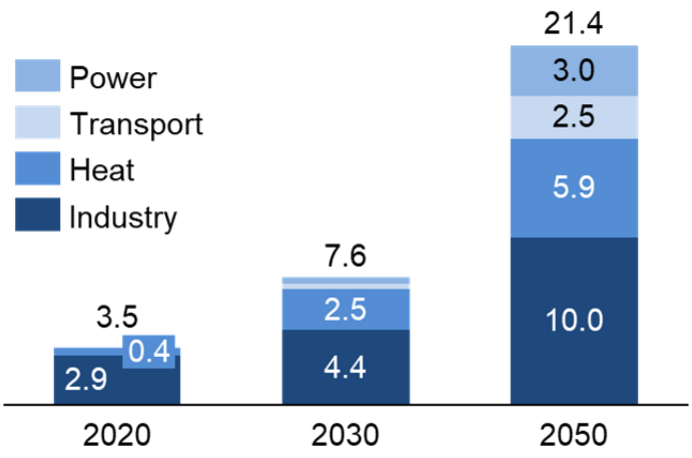

Figure 28: The Netherlands hydrogen demand forecast by end use case (Mtoe)

Netherlands Hydrogen Policy

In March 2020, the Dutch government set out its national strategy on hydrogen[116]. This outlines the importance of hydrogen in achieving a decarbonised energy system. Transitioning away from its reliance on natural gas is key for the Netherlands to achieve its net zero goals[116]. The scaling up of blue hydrogen is also viewed as a necessity in order to scale up green hydrogen in the future. The Netherlands sees itself as a future hydrogen energy hub as it benefits from large ports, significant renewable energy capacity and an existing gas grid that can be used for blending and/or transporting hydrogen. Industry has been identified as the key area for scaling up future hydrogen demand, particularly in the Northern Netherlands industrial clusters. The introduction of a hydrogen 'blending obligation' is also being explored as a way of further increasing demand whilst utilising the infrastructure of the existing gas grid.

Emerging Hydrogen Projects

Hydrogen Valley

By 2026, the Northern Netherlands region aims to develop into a hydrogen valley[117]. A region supporting the full hydrogen value chain from production, to distribution, storage, and local consumption. The industrial areas

[116] Government of the Netherlands 2020, Government Strategy on Hydrogen
[117] Euroactiv 2020, Dutch pin hopes on 'hydrogen valley' to revive declining gas region

of Emmen and Delfzijl will provide an immediate demand for hydrogen to produce methanol and high temperature heat. 100 new homes will be built and are expected to be heated by a combination of hydrogen boilers and fuel cell powered heating. A project schematic for the proposed Hydrogen Valley is displayed in Figure 29.

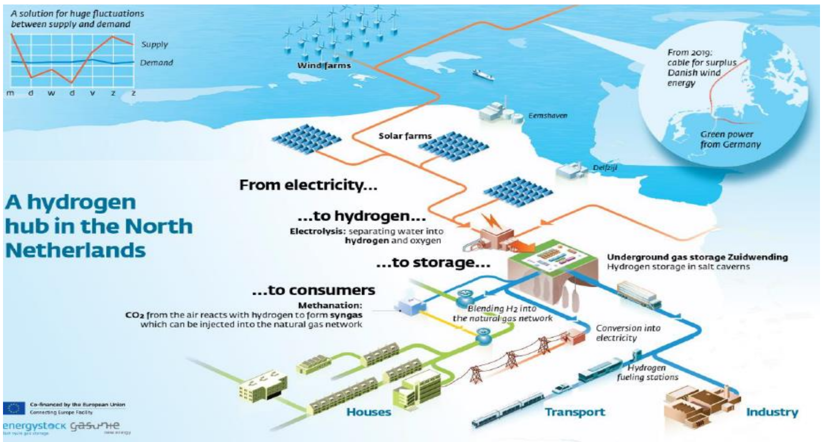

Figure 29: Hydrogen Valley project in the Netherlands[118]

Porthos – Port of Rotterdam

The Porthos project will transport CO_2 captured from various industries located in the Port of Rotterdam. This will involve onshore CO_2 compression and subsequent transportation approximately 20km offshore via a pipeline to a platform. Here, the gas will be pumped 3km underground into an empty gas field for storage beneath the North Sea[119]. It is predicted that 2.5 million tonnes of CO_2 can be stored using this process per year. A project schematic for the Porthos project is shown in Figure 30.

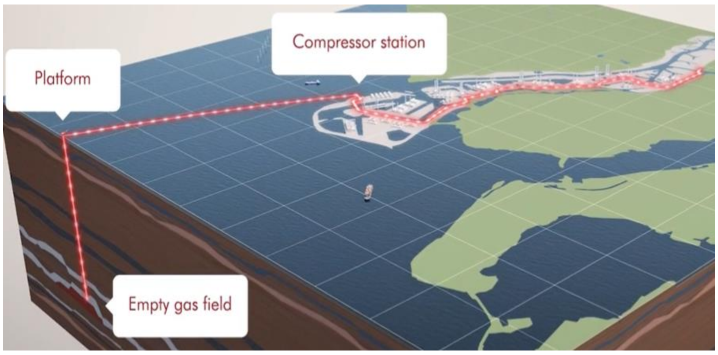

Figure 30: Porthos project in the Netherlands[119]

Summary

The Dutch government has identified hydrogen as a key enabler in transitioning away from the country's reliance on natural gas and achieving its net-zero goals. Blue hydrogen production, including from oil-based feedstocks, will be crucial for scaling up the hydrogen market in the Netherlands whilst green hydrogen production technologies develop. Hydrogen demand is currently provided by the industrial sector; however, significant demand is forecast in the heat sector in 2030 due to plans to blend hydrogen into the existing natural gas grid. Large quantities of crude oil are processed in the Port of Rotterdam refineries providing a reliable supply of feedstock for oil-based blue hydrogen production. The Netherlands is also actively developing shared CO_2 T&S infrastructure in onshore industrial clusters that will transport CO_2 to permanent offshore storage in the North Sea.

[118] Gasunie 2018, Gasunie in a transitioning energy market
[119] Porthos 2021, Project

3.6.3 South Korea

Hydrogen Demand Forecast

The hydrogen demand forecast for South Korea by end use case is displayed in Figure 31.

- **2020** – Hydrogen demand is dominated by industry with minor demand for both heat and power. Hydrogen demand from transport is not significant.
- **2030** – Hydrogen demand more than doubles in the ten-year period but is still dominated by industry. Demands for heat, power and transport begin to grow.
- **2050** – There is significant growth in hydrogen demand across all sectors. Industrial demand is now matched by transport, with the final third of demand being split by heat and power.

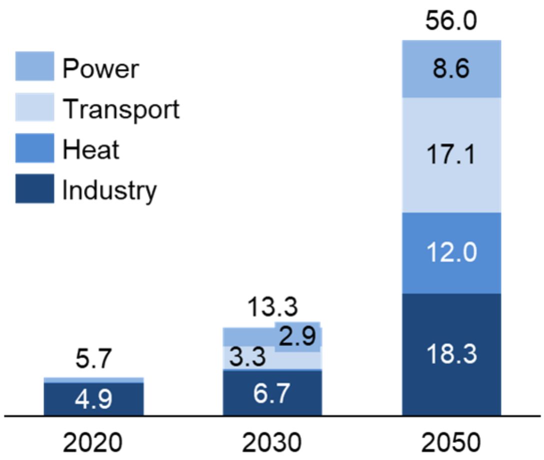

Figure 31: South Korea hydrogen demand forecast by end use case (Mtoe)

South Korea Hydrogen Policy

In 2018, the Ministry of Trade, Industry and Energy announced a budget of approximately 22 billion USD for the establishment of a public-private hydrogen vehicle industry by 2022[86]. In January 2020 – the “Hydrogen Law” was passed by the National Assembly of Korea, outlining the legal basis for the governments support for hydrogen and facility safety standards. South Korea aims to be a world leader in FCEVs and globally registered the greatest number of sales of FCEVs in 2019. South Korea currently relies on fossil fuels to provide 60% of its total energy demand[75]. The government has implemented a nuclear phase out policy, and the country’s conditions are unfavourable for the deployment of renewable energy sources. As a result, hydrogen is seen as a key option for decarbonising the power sector on a large scale. South Korea and Australia have signed a letter of intent for the import/export of hydrogen and hydrogen technologies[120].

Emerging Hydrogen Projects

Hydrogen Cities

The South Korean Ministry of Land, Infrastructure, Transport and Tourism announced plans to create three hydrogen cities by 2022. Hydrogen will be used to fuel heating, cooling, electricity, and transport demand. Hydrogen cities form part of a wider vision in South Korea to power 10% of the country’s towns and cities by 2030, growing to 40% by 2040[121]. A concept of a proposed hydrogen city in South Korea is shown by Figure 32.

[120] CMS 2021, South Korea
[121] World Economic Forum 2019, South Korea is building 3 hydrogen-powered cities for 2022

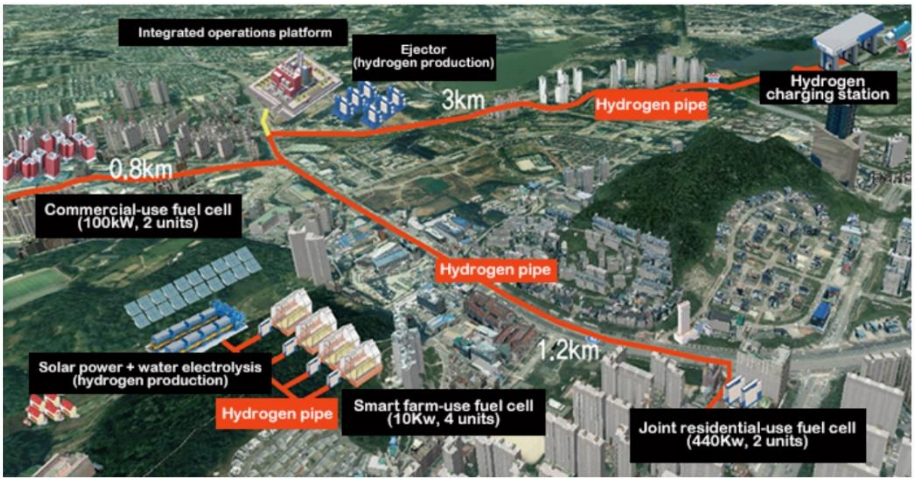

Figure 32: South Korea hydrogen cities plan[122]

Fuel Cell Power Plants

Unlike other countries, South Korea is prioritising large scale stationary fuel cells for power generation. A target of 15GW capacity by 2040 has been set of which 2.1GW is to be applied in buildings[86]. The world's largest hydrogen fuel cell power plant is located in the South Chungcheong Province of South Korea. The plant has a 50MW capacity and utilises by-product hydrogen produced from petrochemical manufacturing[123].

Summary

The South Korean government is actively developing the country's hydrogen market with the aim to develop the country into a world leader in the FCEV technology. Plans for three hydrogen cities by 2022 have been developed where hydrogen will supply all heating, cooling, power, and transport demands. The large-scale deployment of stationary fuel cells in buildings will be a key requirement in achieving these goals. South Korea has limited capacity for producing low carbon hydrogen and will most likely rely on imports to meet the country's growing hydrogen demand. Hydrogen demand currently comes from the industrial sector, however, developments in the transportation and power sectors are expected to provide significant demand in 2030, whilst hydrogen demand for heat is predicted to grow considerably by 2050.

[122] Fuel Cell Works 2019, South Korea to Create Three hydrogen Cities by 2022
[123] Doosan, 2020, Doosan Fuel Cell Builds World's Largest By-Product Hydrogen Fuel Cell Power Plant

4 Infrastructure Assessment

4.1 Overview

It is critical to understand the entire value chain when conducting a techno-economic assessment to produce blue hydrogen. This report explores the remaining parts of the value chain that are needed to deliver blue hydrogen to the global market.

Hydrogen Distribution and Storage Infrastructure

Hydrogen production is largely co-located with points of demand in today's economy due to the relatively small scale of the market. As the demand for hydrogen increases, the point of production becomes more important through access to lower cost energy inputs and feedstocks. Hydrogen distribution over larger distances therefore becomes very important. In addition, storage technologies are also needed to support supply chains and respond to inter-day and inter-seasonal energy demand.

CO_2 Transport and Storage Infrastructure

The other vital part of the value chain is CO_2 T&S infrastructure that ensures that the hydrogen can be classified as blue. In this study, the different CO_2 T&S technology options, including their relative advantages and disadvantages and associated economics, are explored.

Regional Implications

The hydrogen distribution and CO_2 T&S infrastructure is contextualised in five targeted regions. The assessment explores the availability of suitable feedstock and local industry / hydrocarbon reserves, CO_2 storage capacity, and access to hydrogen markets. This analysis is important in defining the scenarios for techno-economic and life cycle assessments in Sections 5 and 6, respectively.

4.2 Hydrogen Distribution and Storage Infrastructure

Hydrogen is a versatile energy vector that can be stored and distributed in different chemical structures and physical states of matter as shown in Figure 33. These different distribution and storage options range in their suitability depending on the length of the route, capacity of hydrogen and technology readiness level. This section considers three different hydrogen archetypes (hydrogen, ammonia, and liquid organic hydrogen carriers (LOHCs)) and their use in different transportation and storage technologies.

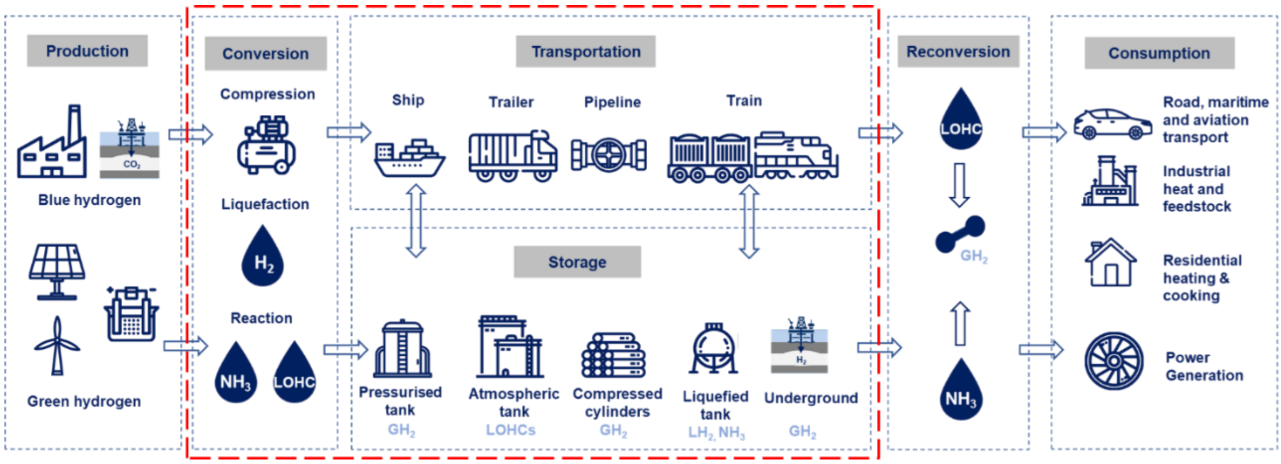

Figure 33: Hydrogen value chain; from point of production to end use

4.2.1 Hydrogen Archetypes

Hydrogen is converted to a form that is suitable for distribution and / or storage once it reaches the battery limits of the production facility. This form is dependent on the optimal distribution and / or storage technology. The different forms of hydrogen highlighted in this report are hydrogen, LOHCs and ammonia. Conversion to suitable carriers comes with an energy burden. This is quoted as a fraction of the lower heating value (LHV) for hydrogen; 33.3 kWh/kg_{H2}.

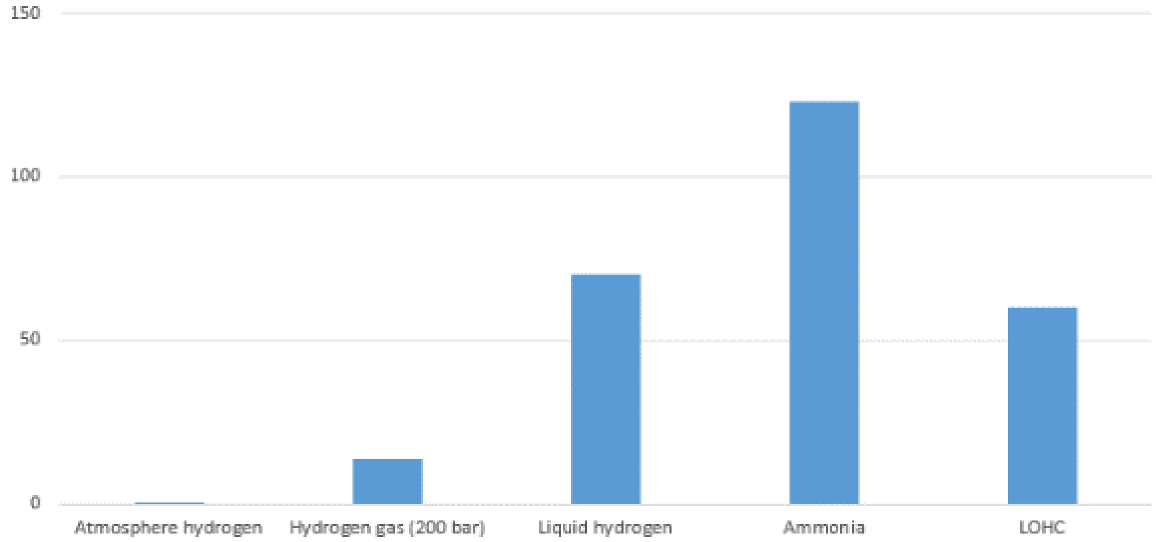

Figure 34: Volumetric density of hydrogen archetypes (kg/m^3)[124]

Hydrogen

Hydrogen at atmospheric pressure has a very low energy density when compared with other archetypes as shown in Figure 34. Energy density is increased when hydrogen is compressed (GH_2) or liquefied (LH_2). Distributing hydrogen as GH_2 or LH_2 also ensures a high purity product at the point of end use. The conversion to GH_2 and LH_2 costs 5-20% and 30-40% in the form of LHV energy penalties respectively[125]. The conversion to GH_2 requires compression (in the range of 200 to 700 bar) and the conversion to LH_2 requires liquefaction, reducing the temperature to -253°C. However, more modern liquefaction plants can reduce this energy burden to 18% at volumes of 50 to 150 tonnes per day[126]. Therefore, it is important to increase the scale of deployment in industrial clusters and points of export to benefit from economies of scale.

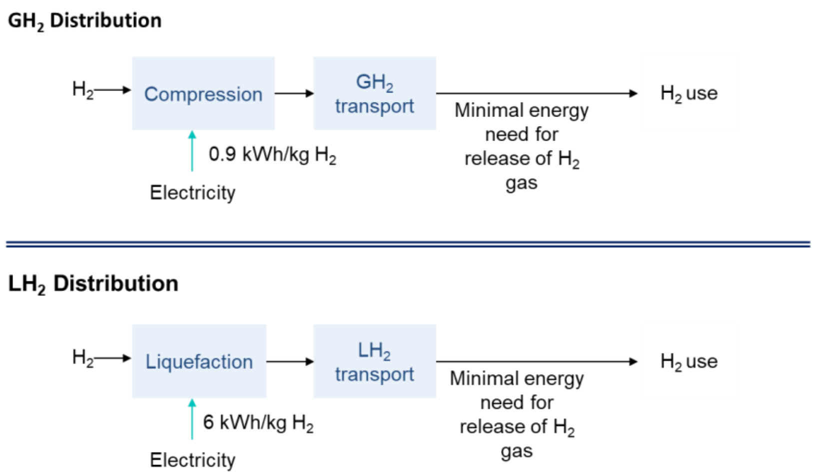

Figure 35: GH_2 and LH_2 conversion and reconversion process[127]

Assumptions on the compression of hydrogen are presented in the Appendices, Section 9.2.7.

[124] Andersson and Grönkvist 2019, Large-scale storage of hydrogen
[125] Letcher, M 2016, Storing Energy With Special Reference to Renewable Energy Sources
[126] Cardella et al 2016, Economically viable large-scale hydrogen liquefaction
[127] IEA 2019, The Future of Hydrogen – Data and assumptions

Ammonia

Ammonia is a promising liquid carrier of hydrogen due to its high volumetric density. Furthermore, the production, distribution and handling of ammonia are all mature processes. However, whilst ammonia is viable in engines, fuel cells and turbines, these technologies have not gained traction in international markets. Therefore, this study focuses on the reconversion back to hydrogen before the molecule is used. The energetic costs associated with the conversion to ammonia and reconversion (including purification) to H_2 remain significant; 7-18% and <20% respectively[4]. From 2040, it is expected that process improvements and economies of scale could reduce these energetic costs by 60% and 70% respectively[73]. Of course, reconversion energetic costs are negated where the ammonia is used as the end product. The choice of carrier is therefore influenced by the end use case.

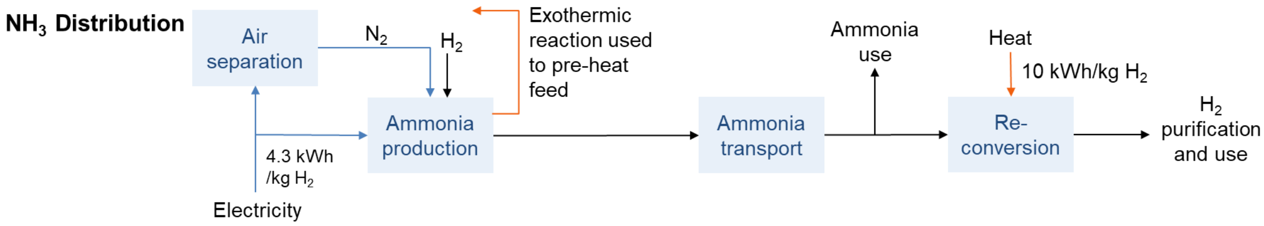

Figure 36: Hydrogen distribution via ammonia process[127]

Liquid Organic Hydrogen Carriers

These are molecules which can be loaded and unloaded with H_2 via hydrogenation and dehydrogenation steps. They are typically 6 wt% H_2[128]. The most notable LOHCs are methylcyclohexane, dibenzyl toluene and N-ethylcarbazole[124]. LOHCs offer improved safety at the expense of a lower volumetric hydrogen density than ammonia. The reconversion costs strongly correlate with the required hydrogen purity and LOHC molecule. This leads to a range of energy penalties, with reports as low as 25%[129] to 40%[4] on an LHV basis. Once LOHCs have been dehydrogenated to extract hydrogen for use, the dehydrogenated LOHCs are returned to their point of origin to reuse.

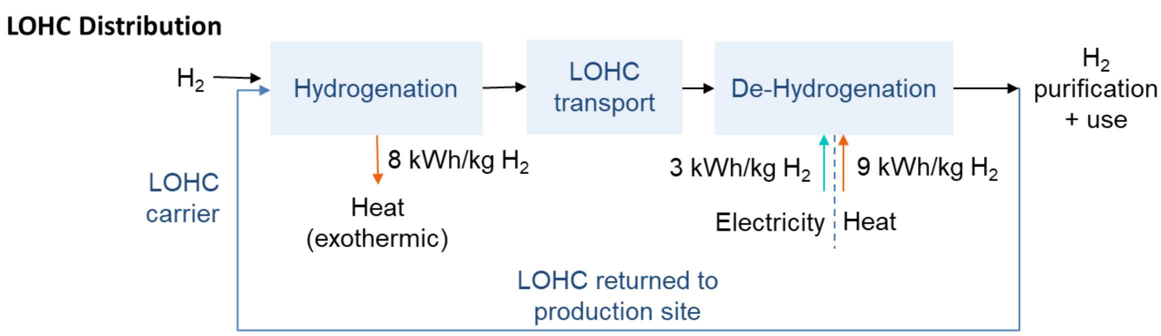

Figure 37: Hydrogen distribution via LOHC process[127]

Methanol

Methanol is predominantly used as a feedstock in the plastics industry. In the energy industry, methanol is used as a fuel (either via direct combustion), blended with petrol, or fed into fuel cells via a reformer. Methanol is a good hydrogen medium since it has a high storage density and there is no need for a return cycle in the logistical supply chain. The fuel also has a high hydrogen density, 12.5 kgH_2/kg_{CH3OH}. It is, however, important to note that the reformation process does result in CO_2 emissions. The use of methanol as a hydrogen carrier has not been explored in this report[130]. As for ammonia, the choice of carrier is influenced by the end use case.

Hydrogen Losses in the Supply Chain

Hydrogen losses occur throughout the distribution chain due to process losses in the conversion steps and through the boil-off of low temperature liquid ammonia and hydrogen. Losses in the hydrogen shipping process

[128] Niermann et al 2019, Liquid organic hydrogen carriers (LOHCs) – techno-economic analysis of LOHCs in a defined process chain
[129] Hank et al 2020, Energy efficiency and economic assessment of imported energy carriers based on renewable electricity
[130] ADI Analytics 2017, Methanol for Power Generation

are shown as an example in Figure 38. The assumed boil off rates and calculated hydrogen losses in delivery are displayed in Table 2 (losses from pipelines and reconversion are not given).

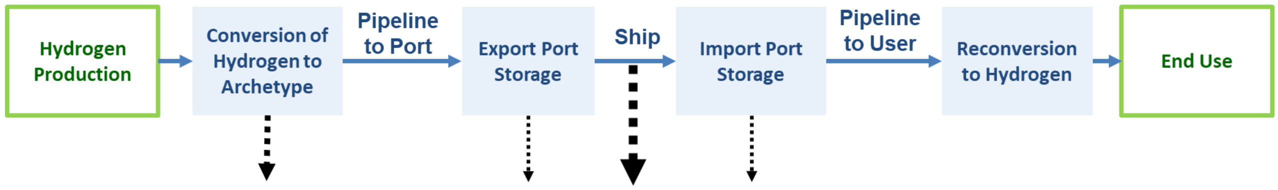

Figure 38: Hydrogen losses in the hydrogen shipping prior to end use

Table 2: Hydrogen losses for distribution via shipping[129, 131, 132]

Assumed daily H_2 loss through supply chain (%.day^{-1})			
Process	**NH_3**	**LOHC**	**LH_2**
Conversion loss	0.0%	0.1%	1.6%
Shipping boil-off	0.04%	0.0%	0.2%
Storage boil-off	0.02%	0.0%	0.1%

Table 3: Comparison of hydrogen archetypes[133]

	GH_2	LH_2	LOHC	NH_3
Description	Hydrogen compressed to between 200 and 700 bar and transported in pressurised vessels	Hydrogen cooled to liquefied at -253ºC and transported in specialised LH_2 vessels	LOHC material (a diesel like fluid) is 'hydrogenated' and transported using existing materials. Material is 'de-hydrogenated' at point of use (requiring heat)	Hydrogen reacted with nitrogen to produce ammonia, which is liquefied (-33ºC) and shipped.
Advantages	+ No re-conversion needed for hydrogen use + No impurities added to hydrogen	+ No re-conversion needed for hydrogen use + No impurities added to hydrogen	+ Re-purpose existing oil infrastructure + No boil off + Stored at ambient temperature	+ Ammonia is already widely distributed + Ammonia can be combusted as a fuel + Low boil-off of 0.04% per day
Disadvantages	- Lower energy density than alternatives - Distribution via pipelines requires grid conversion	- Boil-off of 0.2 % per day (note this can ultimately be used to fuel the ship) - High cost of liquid hydrogen storage vessels	- Need for re-conversion and purification at point of use - High cost of new conversion technologies and LOHC material - De-hydrogenated LOHC has to be transported	- Need for re-conversion and purification at point of use - Corrosive and polluting if leaks - Challenges faced in combustion such as NO_x emissions
Low TRL Supply chain element(s)	Large-scale compression of hydrogen	Liquid hydrogen storage aboard ships	Hydrogenation and de-hydrogenation units have only been demonstrated at small scale	Re-conversion from ammonia to hydrogen and use of ammonia in combustion engines
Energy density (LHV)	0.81 kWh/l (700 bar)	2.4 kWh/l	1.9 kWh/l	3.5 kWh/l (For ammonia use)

[131] European Commission 2018, LOHC production cost estimation study
[132] Idealhy 2013, Hydrogen Liquefaction Report
[133] Rivard et al 2019, Hydrogen Storage for Mobility: A Review

4.2.2 Hydrogen Distribution

Road Transport

Hydrogen

Distribution of hydrogen as GH_2 in compressed cylinders and LH_2 using cryogenic liquid tankers on truck trailers are commercial processes[134]. Many cylinders for GH_2 are made of steel; however, these systems are heavy, leading to reduced hydrogen loading volumes. New cylinders have come and continue to come to market which use composite materials. These systems are lighter, leading to higher hydrogen capacities. They also accept higher pressure hydrogen (>200 bar) leading to higher volumetric energy density.

Ammonia and LOHCs

Ammonia and LOHCs can also be transported in trailers. Their higher volumetric energy density, when compared with liquid and compressed hydrogen, leads to higher hydrogen capacities per trailer. Ammonia distribution is a commercial process, developed from the fertiliser and agriculture industry. LOHCs can simply use steel tanks, as is used in the transportation of road fuels such as diesel[135].

Suitability

This form of hydrogen distribution is best suited for small quantities of hydrogen over short distances where demand is geographically spread. This leads to flexibility in terms of deployment. A process flow of hydrogen distribution via road is shown in Figure 39.

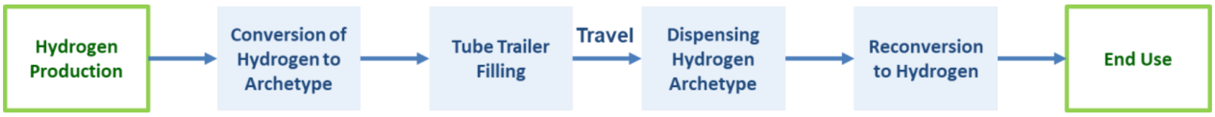

Figure 39: Hydrogen distribution via road transport process flow

Rail Transport

Hydrogen

Distribution by train is similar to distribution by road. GH_2 and LH_2 can both be stored in compressed pressure vessels and cryogenic tanks, respectively. The benefit of distribution by rail over road is the increased volume of hydrogen that can be distributed per journey.

Ammonia and LOHCs

This is also true for both ammonia and LOHCs. One rail tank car can distribute four times more hydrogen than by trailer. These distribution archetypes also have the benefit of being able to reuse pre-existing infrastructure at train depots and loading points.

Suitability

Distribution is limited to where railway routes exist between a point of production and demand. Where this is both feasible and demand is significant enough to bring economies of scale to the conversion and re-conversion of hydrogen, this is more cost effective than distribution by road. A process flow of hydrogen distribution via rail is shown in Figure 40.

Figure 40: Hydrogen distribution via rail transport process flow

[134] Hydrogen Europe 2021, Tech Descriptions
[135] Reuß et al 2017, Seasonal storage and alternative carriers: A flexible hydrogen supply chain model

Pipelines

Pipelines can transport both liquids and gases, operate at different pressures depending on the pipeline size, material, and regulate their flow to balance supply and demand. The operational costs of pipelines are also comparatively low. This means that increased utilisation improves the economics. Pipelines can be used as an interoperable network interconnection between multiple producers and consumers. However, they require substantial planning, especially if crossing environmentally protected or high-density areas. A process flow of hydrogen distribution via pipeline is shown in Figure 41.

Hydrogen Pipelines

Most H_2 pipelines are currently found in industrial clusters, delivering feedstock. The most practical form of hydrogen is GH_2. This builds up linepack capacity (gas stored in the pipeline), guaranteeing a constant supply of H_2. Work is ongoing to explore dedicated blends of hydrogen in gas networks. Hydrogen can be safely mixed in small quantities in natural gas grids, helping to reduce the carbon intensity of gas networks. This is further discussed in Box 2. The large natural gas volumes used in energy systems implies that even small hydrogen blends can attain large levels of carbon abatement.

Figure 41: Hydrogen distribution via pipeline transport process flow

Box 2 Hydrogen Blending in Natural Gas Pipelines

Blending hydrogen constitutes a low-regrets decarbonisation option. This is because up to 20% v/v into the gas grid requires minimal or potentially no modifications to grid infrastructure or to domestic end-user appliances[136].

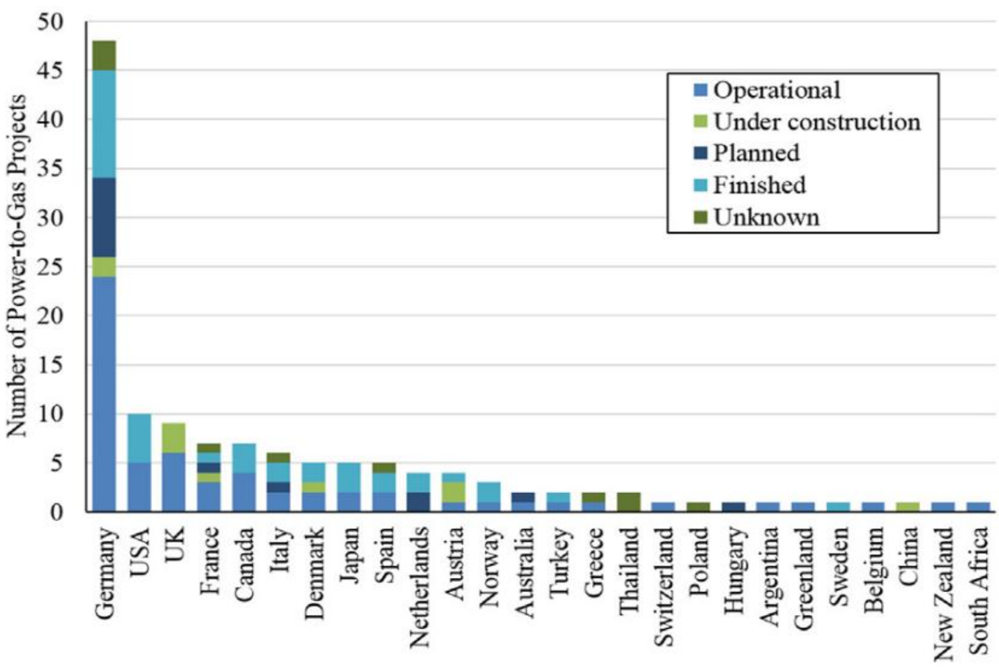

Figure 42: Locations of power-to-methane/hydrogen projects around the world[137]

[136] IEAGHG 2003, Reduction of CO_2 Emissions by Adding Hydrogen to Natural Gas
[137] Quarton and Samsatli 2018, Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling?

Interest was initially limited to Europe, however, since 2017 there is also widespread interest in other countries (such as Australia, Canada, and the United States) in hydrogen blending into natural gas pipelines, both at the transmission and distribution levels.

Numerous projects around the world are investigating the potential for blending and how blending can help support the wider hydrogen value chain (including production, storage etc.) and boost low carbon hydrogen demand. Countries developing hydrogen power-to-gas projects around the world in 2018 are displayed in Figure 42. These projects aim to demonstrate safe and technically viable operations. Work is ongoing to explore purification of hydrogen downstream. Blending of hydrogen in gas networks, as well as repurposing current infrastructure for distribution is currently limited by a series of overarching challenges as shown below:

Technical:

Embrittlement:

Hydrogen can cause embrittlement of the high strength carbon steel used in transmission pipelines, increasing material fatigue, and reducing their useful life.

Replacing of equipment:

Compressors may require replacement or adjustment to increase the energy flow volume.

Reinforcement works:

Additional capacity may be required due to hydrogen's lower energy density.

Loss in the gas line pack storage:

Decrease in energy density leads to an overall loss in the gas line pack storage in pipelines, and additional storage facilities may be required.

Regulatory:

Maximum limits:

Regulated maximum concentration of hydrogen in gas networks tends to be generally very low across countries. Many hydrogen blending projects are considering blends above limits.

Cross-border flows:

Variation in blending regulations may complicate the cross-border flow of hydrogen in transmission systems.

Lack of policy incentives:

Pathway to commercialisation requires incentivizing low-carbon hydrogen producers and ensuring that higher prices do not lead to a financial burden and increased project risk.

Commercial:

Deblending:

Some equipment can be sensitive to the composition of the natural gas supply and may require deblending to remove the hydrogen. Commercial challenges include the lack of business models to distribute deblending costs and ownership of deblending operations.

Commercial agreements:

Commercial agreements between TNOs and DNOs are needed for hydrogen blending, as there has to be mutual understanding on the impacts which each supply chain level have on each other.

Safety:

Increased understanding is needed:

Increased probability and severity of ignition in repurposed pipelines is still to be fully understood and current risk management practices may have to be adjusted.

Use of hydrogen in households:

Hydrogen blends above 20% will require the replacement of domestic boilers to hydrogen-specific designs. Overcoming some issues like flame detection by boilers (as hydrogen burns almost invisibly) and identification of new odorants to detect leaks is also needed.

Ammonia and LOHCs

Ammonia pipelines are also very mature. These have been used to service the fertiliser, oil, and gas industries for decades. Pipelines to transport LOHCs can also reuse existing infrastructure currently used for liquid fuels such as gasoline and diesel. However, the use of LOHCs in pipelines are limited as the LOHC must be transported back to the point of production for reuse. This would require twice the infrastructure as for dedicated hydrogen and ammonia pipelines.

Shipping

Shipping is well suited for long distance travel and can facilitate the development of global hydrogen supply chains. This will connect regions which produce low-cost hydrogen with those who have established hydrogen economies.

Hydrogen

Shipping LH_2 is still only at a demonstration phase. The transportation of GH_2 via ship is not viable due to its low energy density. As well as development of the ships themselves, work is needed on developing the port and storage infrastructure. With an increase in the size of hydrogen markets, the costs of shipping LH_2 could fall by 90% by 2030[138].

Ammonia and LOHCs

Both LOHCs and ammonia can utilise existing port infrastructure that currently service liquid fuels. Ammonia distributors utilise chemical and semi-refrigerated liquefied petroleum gas / propane tankers. LOHCs distributors can utilise oil tankers but would still need to organise a return to the original port to reuse the LOHC.

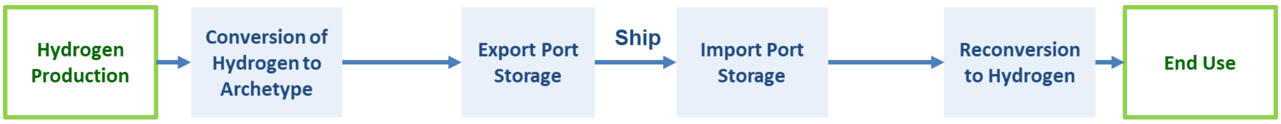

Figure 43: Hydrogen distribution via shipping process flow

Hydrogen Distribution Economics

The economics of hydrogen distribution are assessed by comparing those technologies and archetypes suitable for long-distance, medium-distance and last-mile delivery[4]. The economics presented in these sections only consider the distributed cost of hydrogen. The costs of purification, liquefaction and conversion / re-conversion are omitted.

These costs will be included in the full techno-economic analysis. Overall supply chain costs are dependent on scale. However, indicative costs taken from the IEA's "The Future of Hydrogen" and are displayed in Figure 44.

- **LH_2 –** Liquefaction cost of \$1.00/kgH_2
- **Ammonia –** Conversion to ammonia (NH_3) cost of \$1.00/kgH_2 and conversion back to H_2 cost of \$0.75/kgH_2
- **LOHC –** Conversion to LOHC cost of \$0.40/kgH_2 and conversion back to H_2 cost of \$1.00/kgH_2[4]

[138] Hydrogen Council 2020, Path to Hydrogen Competitiveness: A Cost Perspective

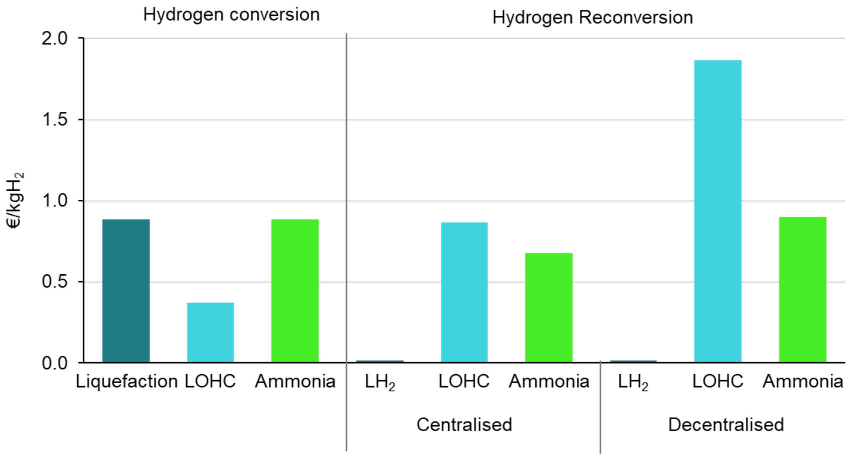

Figure 44: Hydrogen conversion costs (left) and reconversion costs (right)[4]

Long Distance Economics

This analysis spans a distance of 500 km to more than 3,000 km and focuses on high volumes of hydrogen distribution. As a result, the technology choices are limited to pipelines and shipping. The pipeline costs are based on onshore costs. As a rule of thumb, offshore pipeline costs are roughly twice as expensive as onshore pipelines[139]. The main contributing factors to the cost of distribution is the distance of travel and transport volume requirements. These cost trends for pipelines are more sensitive to increasing distances than ships, as the longer the pipeline the more compressors/pumps are required. For shipping, this merely arises from the increase in fuel costs. Shipping is more cost effective than pipelines for longer distances as shown in Figure 45. However, this needs to be assessed on a case-by-case basis as the cost of pipelines is dominated by their capital cost. A greater throughput will therefore change the breakeven point between shipping and pipelines as more ships will be required.

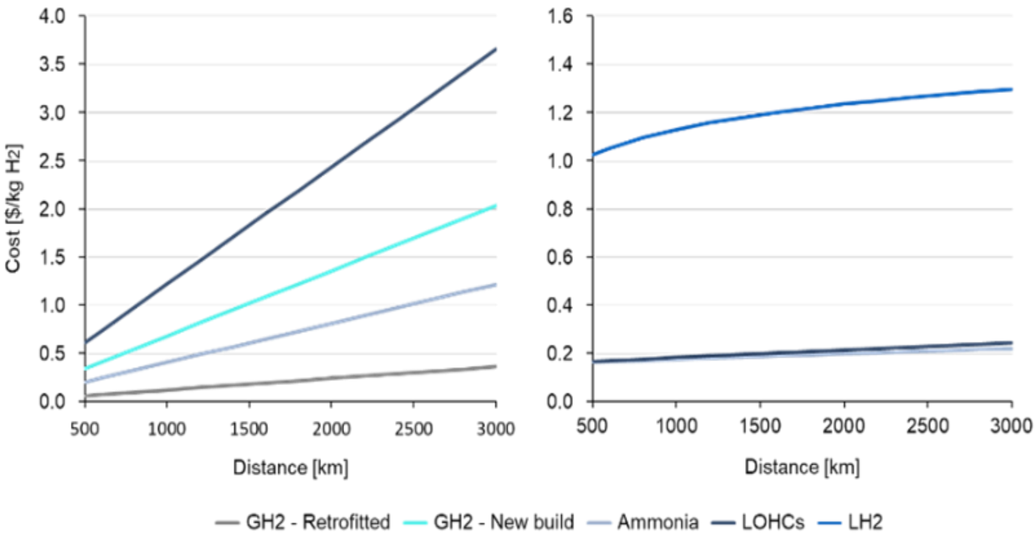

Figure 45: Levelised cost of hydrogen distribution for long-distance transportation of hydrogen via pipeline (left) and ship (right)[140, 141, 142, 143]

[139] Global Energy Monitor 2020, Oil and Gas Pipeline Construction Costs
[140] Levelised costs for transportation is defined as the present value of the transported hydrogen price, considering the economic life of the transportation method and the costs incurred during the construction, operation, and maintenance.
[141] Navigant, Gas for Climate: Optimal Role for Gas in a Net Zero Emissions Energy System (2019). LOHC molecule and transportation volumes not specified.
[142] Various gas operator authors, European Hydrogen Backbone, (2020). GH_2 pipeline – Retrofitted: Transportation of 5,000 tpd H_2.
[143]IEA, The Future of Hydrogen (2019): Transportation volumes per pipeline: 340 tpd H_2 for GH_2 new build and 240 tpd H_2 for ammonia. Transportation volumes per ship: 11,000 tonnes for LH_2; 110,000 tonnes for LOHCs (toluene) and 53,000 tonnes for ammonia.

Medium Distance Economics

There are more technological options to consider for shorter distance, ranging tom 100 to 1,500 km. This now includes tube trailers and trains in addition to pipelines. Transportation by rail is notably the lowest cost as shown by Figure 46 (note the different cost scales); however, this is reliant on the availability of infrastructure. Additional costs of refilling and dispensing infrastructure, as well as the cost of the railway itself for unconnected regions, has not been assessed due to data availability and geographic specificity. As shown for the cost of distribution via pipeline, higher throughputs yield lower distribution costs as the utilisation of the capital infrastructure is increased. LH_2 and ammonia distribution via trailer closely follow the 500tpd pipeline. However, logistical factors need to be considered. For example, one 100 tpd pipeline is roughly equivalent to 23 LH_2 trailers. In general, the transportation via trailer is the most sensitive to transportation distance.

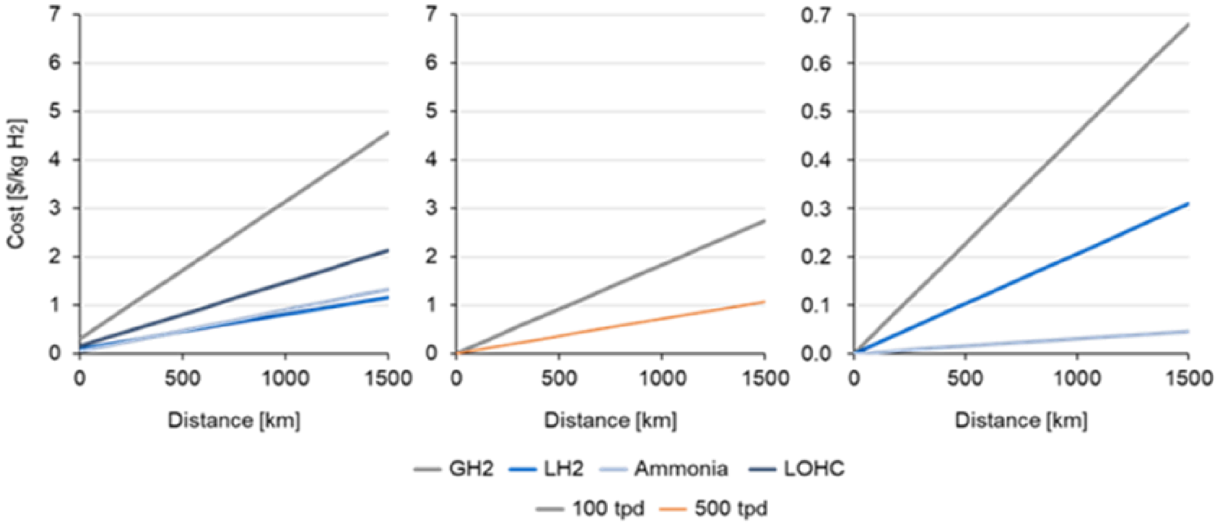

Figure 46: Levelised cost of hydrogen distribution for medium-distance transportation of hydrogen via road-trailer (left), pipeline (centre) and rail (right)[144, 145]

Short Distance Economics

This analysis focuses on hydrogen distribution distances up to 50 km, with the aim of delivering hydrogen to the end user (often called 'last mile' delivery). This is expected in the case of hydrogen delivery to hydrogen refuelling stations for the transport sector. GH_2 pipelines and trailers containing GH_2 and LH_2 are considered for short distance distribution as shown in Figure 47. LOHCs and ammonia are not considered as it is assumed that the last-mile delivery does not include reconversion processes. As shown again for the pipelines, the hydrogen distribution cost is a significant function of distribution distance. The lowest cost option is a retrofitted pipeline, where the technical and regulatory barriers described previously can be overcome. For trailers, the error bars show the variation over the 10 to 50 km range, highlighting the effectively fixed cost for the given capacities over this distance. The distribution costs for the trailers shows that LH_2 is more economic, but this needs to be supplied at large enough scales. For example, 0.50 tpd to 5.00 tpd is equivalent to a 25 to 250 bus depot.

[144] IEA, The Future of Hydrogen (2019): Transportation volumes per trailer: 670 kg H_2 for GH_2; 4,300 kg H_2 for LH_2; 1,800 kg H_2 for LOHC and 2,600 kg H_2 for ammonia.
[145] Train costs from Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018) National Hydrogen Roadmap. CSIRO, Australia. GH_2 (430 bar, 36.2 m^3 H_2), LH_2 (56.2 m^3 H_2) and ammonia (3.8 tonnes H_2).

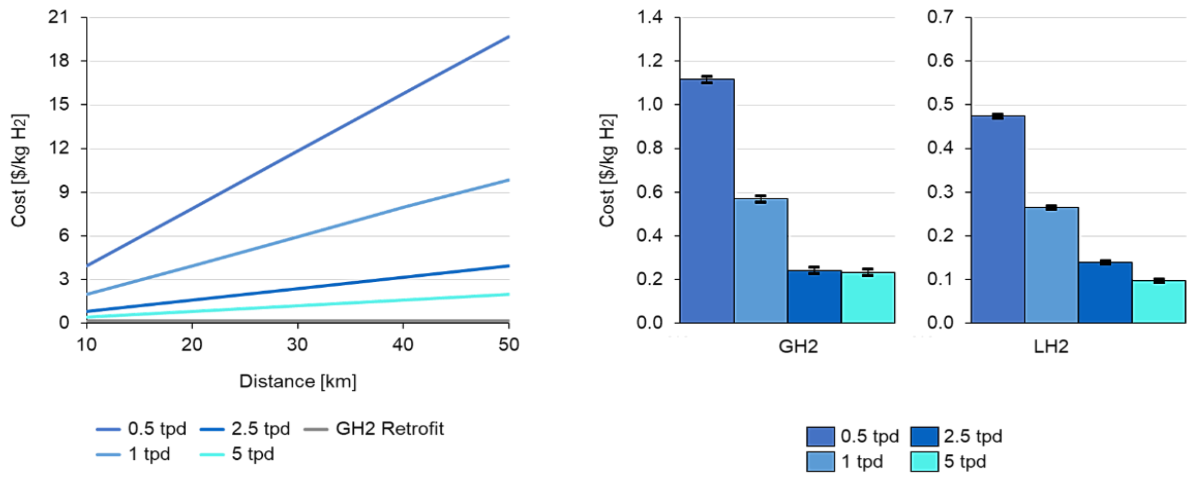

Figure 47: Levelised cost of hydrogen distribution for last-mile delivery of hydrogen via pipeline (left) and trailer (right)[146]

4.2.3 Hydrogen Storage

It is important to consider different hydrogen storage options and strategies since hydrogen gas has a low volumetric energy density at atmospheric conditions and a low boiling point. Fortunately, hydrogen is a versatile energy vector. This means that suppliers, distributors, and end users can store hydrogen in different ways between the point of production and end use. This section considers GH_2, LH_2, LOHCs and molecular carriers such as NH_3 as shown in Figure 48. These different technologies possess advantages and drawbacks depending on scale, storage longevity, local geology / geography and use case. Hydrogen storage largely falls into two categories:

- **Centralised Storage** - Large scale storage for inter-seasonal purposes. Demand is low in the summer and high in the winter to match heating requirements. Salt caverns, depleted oil and gas fields, aquifers and rock caverns are expected to provide much of this storage.
- **Distributed Storage** - Found closer to the point of end use and distribution to meet short-term local demand. Storage of this type includes liquid hydrogen, pressurised tanks and compressed cylinders, atmospheric tanks, and metal hydrides.

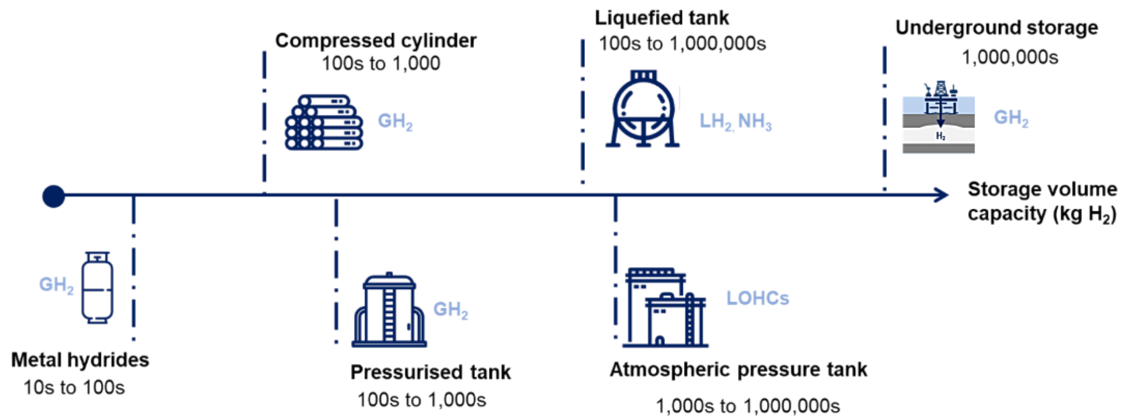

Figure 48: Hydrogen storage options by capacity[147]

[146] Element Energy internal modelling. Assumptions: HRS utilisation=90%, trailer lifetime=11 years, trailer capacities=4,000 kg (LH_2) and 1,000 kg (GH_2), diesel HGV tube trailer powertrain. Depending on design capacity, liquefaction costs for LH_2 add anywhere in between \$1/kgH_2 to \$1.3/kgH_2 whereas compression costs for GH_2 add \$0.3/kgH_2.
[147] Analysis based on Element Energy assessment

Underground Storage

Underground storage systems include salt caverns, depleted oil and gas fields, aquifers, and rock caverns[148, 149]. These systems have capacities of terawatt hours of H_2 and are orders of magnitude larger than any other storage technology considered in this study. As a result, these systems are particularly well-suited to inter-seasonal energy demand. Salt caverns and rock caverns, on the other hand, can also be used for intra-day, daily and weekly operation.

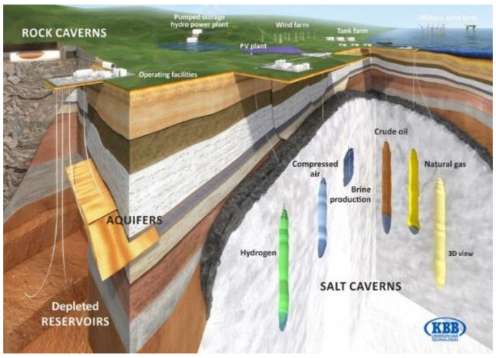

Figure 49: Underground hydrogen storage options[150]

The main determining factor in the use of these geological features is the stability of the cavern wall. This is to protect the walls from rapid changes in lithostatic pressure (the natural pressure in the surrounding rock – increases with depth). The working volume is defined by lithostatic pressure; the working pressure is restricted to 30%-80% of the lithostatic pressure. The discharge rate varies depending on the storage system. However, this has been generalised to approximately 10% of the contained volume per day (as long as the lithostatic pressure boundaries are maintained).

Of the storage options, salt caverns are the most promising as hydrogen purity is not compromised[151]. An example schematic of underground hydrogen storage in salt caverns is displayed in Figure 49. In addition, artificially constructed cavities are less likely to leak and require less operating pressure than other underground options.

In all cases, compression is needed at the storage site. Salt caverns have been used in the UK, in the Tees Valley, for hydrogen storage. Potential hydrogen storage sites for the UK and Europe are displayed in Figure 50.

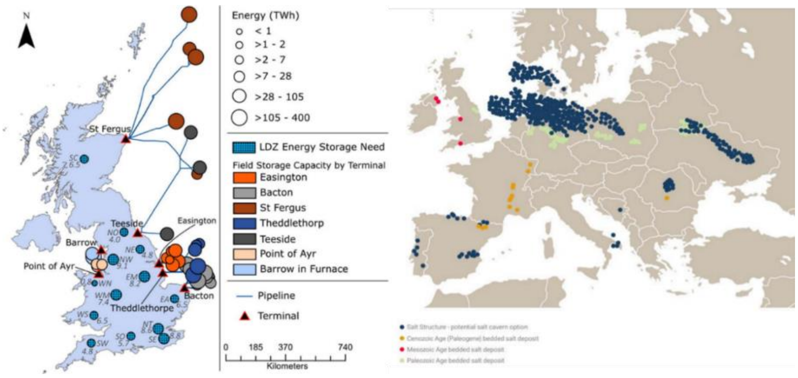

Figure 50: Mapping geological hydrogen storage in the UK[152] (left) and offshore salt structures in Europe[153] (right)

148 Element Energy for BEIS 2018, Hydrogen supply chain evidence base
149 Sandia National Laboratories 2011, A Life Cycle Cost Analysis Framework for Geologic Storage of Hydrogen
150 Crotogino et al 2017, Renewable energy storage in geological formations
151 Storing Energy 2016, Salt Cavern
152 Mouli-Castillo et al 2021, Mapping geological hydrogen storage capacity and regional heating demands: An applied UK case study
153 Caglayan et al 2019, Technical Potential of Salt Caverns for Hydrogen Storage in Europe

In all cases, compression is needed at the storage site. Salt caverns have been used in the UK, in the Tees Valley, for hydrogen storage. Potential hydrogen storage sites for the UK and Europe are displayed in Figure 50.

Pressurised Tanks and Compressed Cylinders

The storage of GH_2 in pressurised systems is well established and has a high technology readiness level. These systems are largely used in the transportation and industry sectors as they can be flexibly deployed. The transport sector uses individual cylinders to store GH_2 onboard vehicle and at small scales in HRS. Larger scale systems also feature at industrial sites and larger HRS. The capacity of these storage systems spans several orders of magnitude: from 10s of kilograms to low tonnes of hydrogen.

This technology is best suited for intra-day and inter-day storage, where hydrogen needs to be readily available. They can handle high cycle rates and are affected by hydrogen discharge. The costs of these systems increase as the storage duration and pressure of storage increases as shown by Figure 51.

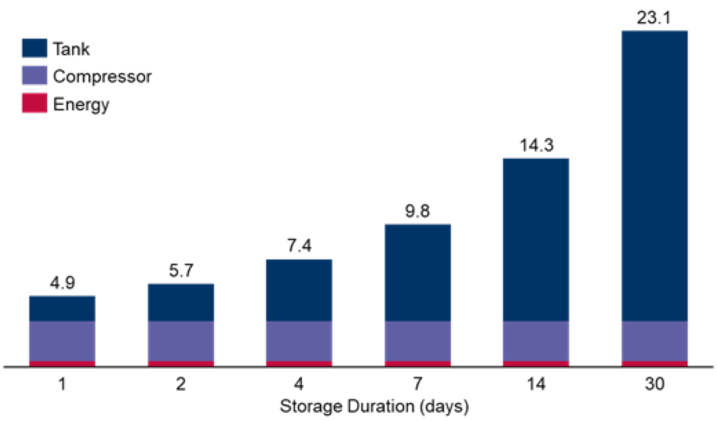

Figure 51: Levelised cost of storage according to storage duration with a fixed rate of production (€/MWh)[154]

There are different types of hydrogen cylinders and tanks; this is defined by their construction material. The cheapest and lowest pressure technology (Type I) is made of steel and has an upper limit of 200 bar. Types II and III use some amount of composite material, whereas Type IV is purely made of materials such as carbon fibre. This increases the cost but also the storage pressure (up to 700 bar)[155]. In addition to the cylinders and tanks, the storage site needs compressors, manifolds (high pressure piping) and storage racks.

Liquified Hydrogen Tanks

Liquified hydrogen has a significantly higher energy density than hydrogen in gaseous form. This is made possible by reducing the temperature of hydrogen to -253°C at atmospheric pressure in an insulated, spherical tank. This is a well-established technology that is widely used in industrial settings. Over time, some of the hydrogen will boil off due to heat transfer into the vessel. This hydrogen is vented off so that the pressure in the tank does not increase. In certain applications, boiled off hydrogen can be utilised and so does not present an additional cost. For example, the IEA estimated that a hydrogen transporting ship could be powered by the 0.2% of its cargo that boils off each day[4]. These systems are expensive, both in terms of capital equipment and operating costs. It is therefore important to use these systems in industrial settings or large H_2 refuelling stations with high utilisation rates.

Liquefied Ammonia Tanks

It is also possible to store hydrogen in the form of ammonia. This is favourable due to its high volumetric energy density and the fact that his can be done at low pressures of 10 bar and atmospheric temperatures. The conversion of hydrogen to ammonia via the Haber-Bosch process is well understood, as is the transportation and storage of ammonia. It is possible to use ammonia in various applications, such as fuel cells and internal combustion engines, however these are not yet commercial. Instead, it is possible to convert the ammonia

[154] A.t. Kearney Energy Transition Institute 2014, Hydrogen-Based Energy Conversion
[155] Composites World 2012, Pressure vessel tank types

back into hydrogen. This is technically viable but the energy requirements and resulting hydrogen purity in the reconversion process remain a challenge. In addition, the conversion and reconversion processes carry energy penalties of up to 20% of the lower heating value of H_2.

Atmospheric Tanks

LOHCs also hold significant promise for both hydrogen storage and distribution. Reconversion costs are strongly linked with purity requirements and, as for ammonia, there are a range of energy penalties depending on the LOHC. As these liquids can be stored at atmospheric conditions, it is possible to reuse existing oil and gas infrastructure where the supply chains are already present, i.e., industrial clusters and gas terminals.

Figure 52:LOHC utilisation cycle[156]

Metal Hydrides

Metal hydrides are an emerging storage technology and are currently low TRL (approximately level 3 to 4). In these materials, the hydrogen molecules are broken down and bonds are formed with the metal hydrides. More advanced technologies include magnesium hydride and aluminium hydride. These technologies have historically been used in niche applications where storage weight is not an issue, such as forklifts, submarines and scooters.

There are concerns with the limited reversibility, decomposition of the storage material and its slow reaction kinetics. Further work is needed to advance the technology in these areas[157].

Inter-Seasonal Storage

For the storage volumes considered in Figure 53, LOHCs and ammonia show lower costs than the majority of the GH_2 storage options.

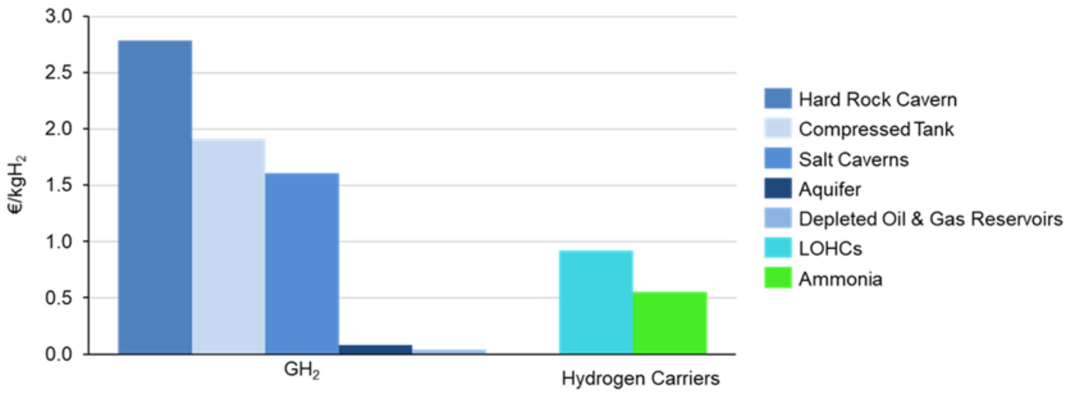

Figure 53: Levelised cost of hydrogen storage for inter-seasonal energy storage of hydrogen via GH_2 (*left*) and hydrogen carriers (*right*) provided from analysis of storage suppliers – (€/kgH_2)[158, 159, 135,149]

However, when considering the effects of conversion and reconversion costs, the levelised cost of storage is expected to be similar to GH_2 storage in compressed tanks and salt caverns. Aquifers and depleted oil and gas reservoirs are the lowest cost shown here. However, this does not include the purification steps required from this type of storage due to the impurities that are introduced to the gas.

[156] Mission Innovation 2021, Liquid Organic Hydrogen Carriers
[157] Rönnebro, E 2012, Technology and Manufacturing Readiness of Early Market Motive and Non-Motive Hydrogen Storage Technologies for Fuel Cell Applications
[158] Argonne National Laboratory 2019, System Level Analysis of Hydrogen Storage Options. GH_2 compressed underground pipes: 500 tonnes of H_2 and discharge cycle of 10 days (50 tpd).
[159] Jeffrey, B 2008, A Feasibility Study of Implementing an Ammonia Economy. Ammonia pressurised vessel capacity: 15,000 tonnes of ammonia, one full cycle per year.

Intra-Day Storage

Intra-day storage economics are heavily dependent on cycle rates, hydrogen capacities, discharge and compression rate requirements. These factors largely impact the operational costs and are not included here. The levelised capital costs of the storage technologies are analysed as part of this study as shown in Figure 54 where error bars show the range of data points. This figure reflects the technical maturity of tube trailers and pressurised vessels used by industry however, liquified hydrogen and metal hydrides are expected to benefit from economies of scale and commercial maturity in the future. In addition, liquified hydrogen levelised cost is heavily dependent on the system capacity, shown by the significance of the error bars.

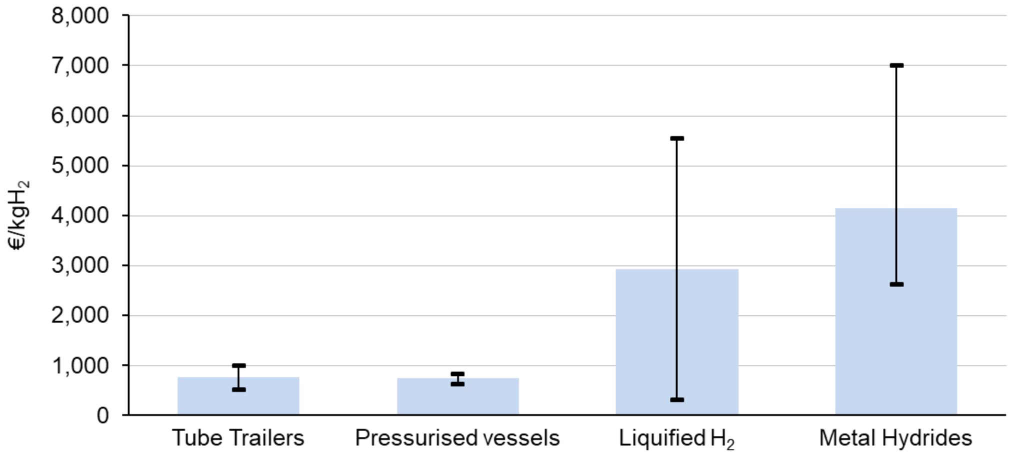

Figure 54: Average total capital cost of pressurised vessels normalised to storage capacity with upper and lower limits – (€/kgH_2)[160, 161, 162, 163]

Hydrogen Distribution and Transportation Summary

A summary of hydrogen storage and distribution technologies is presented in Table 4.

Table 4: Comparison between hydrogen transportation and distribution methods

		GH_2	LH_2	Ammonia	LOHCs	Metal Hydrides
Supply chain integration		High	High/Medium	High	Medium	Medium/Low
Transportation TRL	**Ship:**	High	Medium	High	High	-
	Pipeline:	High	High	High	Medium	-
	Train:	High	High	High	Medium	Low
	Truck:	High	High	High	High	Low
Storage TRL	**Tank:**	High	High	High	High	High
	Tubes:	High	-	-	-	-
	Underground:	Medium	-	-	-	-
Transportation suitability scale	**Pipeline:**	10's kt	-	10's kt	10's kt	-
	Ship:	-	90t	10's kt	10's kt	-
	Truck:	1t	4t	3t	2t	100's kg
Storage suitability at different scales	**Cavern:**	10 kt	-	-	-	-
	Tank:	1 t	5t	30t	80kt (18kt H_2)	10's kg

4.2.4 Summary

Blue hydrogen derived from oil and oil-based products needs scale in transportation and storage technologies for distribution to major hydrogen markets. This is highlighted further in Section 8.3. Many stakeholders are actively exploring projects involving national distribution as well as international trade that would facilitate these

[160] Tube trailers and pressurised vessels calculated using internal Element Energy analysis. Tube trailer capacity volumes: 320 kg H_2 to 1,100 kg H_2. Pressurised vessel capacity volume: 300 kg H_2 to 1,000 kg H_2.
[161] Tzimas et al 2003, Hydrogen Storage: State-of-the-Art and Future Perspective. Liquefied tank capacity volumes: 1,000 kg H_2 to 150,000 kg H_2.
[162] Ganda et al 2018, Economic Data and Modelling Support for the Two Regional Case Studies: Nuclear-Renewable Hybrid Energy Systems: Analysis of Technical & Economic Issues. Metal hydride capacity volume: 160 kg H_2 to 890 kg H_2.
[163] Bornemann, N 2018, GKN's Solid-state Hydrogen Storage System

requirements. Although further work is still needed to bring these technologies to commercial maturity and initial projects are expected to focus on local demand, the increasing demand for hydrogen will lead to scale in hydrogen distribution and will enable the use of oil—based hydrogen in major hydrogen markets.

4.3 Carbon Dioxide Transportation and Storage Infrastructure

CCS facilities have grown in capacity and number over the past few years, driven largely by national net-zero targets. CCS technology is a game changer in the fight against significant and irreversible climate change. The Intergovernmental Panel on Climate Change (IPCC) identified four illustrative pathways limiting global temperature rise to 1.5°C, three of which required significant use of CCS[12].

CCS developments have traditionally adopted a point-to-point model. This is where a single large CO_2 emitter is located close to a large CO_2 storage site. The cost of CCS infrastructure has often been a barrier to many deployments. However, with the increased interest in the development of these hubs, commercial synergies are possible via multilateral collaboration between emitters who share and utilise CCS infrastructure. This reduces investment risks and helps to achieve economies of scale.

Installed CCS capacity reached approximately 40 $MtCO_2$ in 2020. A world map of CCS facilities in various stages of development is shown in Figure 55. It is predicted that CCS capacity needs to increase by more than a hundred times to achieve net zero emissions by 2050[12].

Figure 55: World map of CCS projects at different stages of development[12]

4.3.1 CO_2 Transportation

It is more cost effective to transport CO_2 in a dense (not gaseous) form since gaseous CO_2 has a low density. However, CO_2 only exists in a gaseous or solid form at atmospheric pressure as shown by Figure 56. CO_2's triple point (where it exists in all three states) is achieved at a pressure of 5.18 bar and temperature of -56.6°C. A substance becomes a supercritical fluid when it is above its critical temperature and pressure. For CO_2, the supercritical state is above 31.1°C and 73.8 bar and is thus easily accessible in comparison to other solvents. Liquefying CO_2 near the triple point requires refrigeration systems, whereas significant compression is required to liquefy CO_2 near the critical point. Through the process of liquefaction, CO_2 is transported at or above the boundary between the liquid and gaseous phase, at pressures greater than atmospheric pressure.

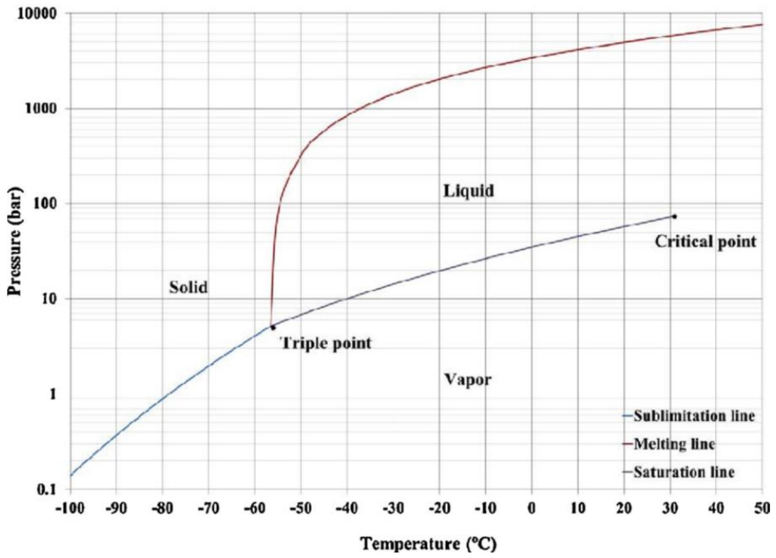

Figure 56: CO_2 pressure-temperature phase diagram[164]

Pipelines

Pipelines are currently the most common method of transporting very large quantities of CO_2. There are currently over 8,000 km of pipeline infrastructure worldwide with the majority located in the USA[165], demonstrating the technology's maturity. Pipelines are a well understood transportation technology, particularly in the oil and gas sector. Most the world's current pipeline networks are used for transporting hydrocarbons, both onshore and offshore. CO_2 transport via pipeline is predicted to remain the preferred transportation method in the future[166].

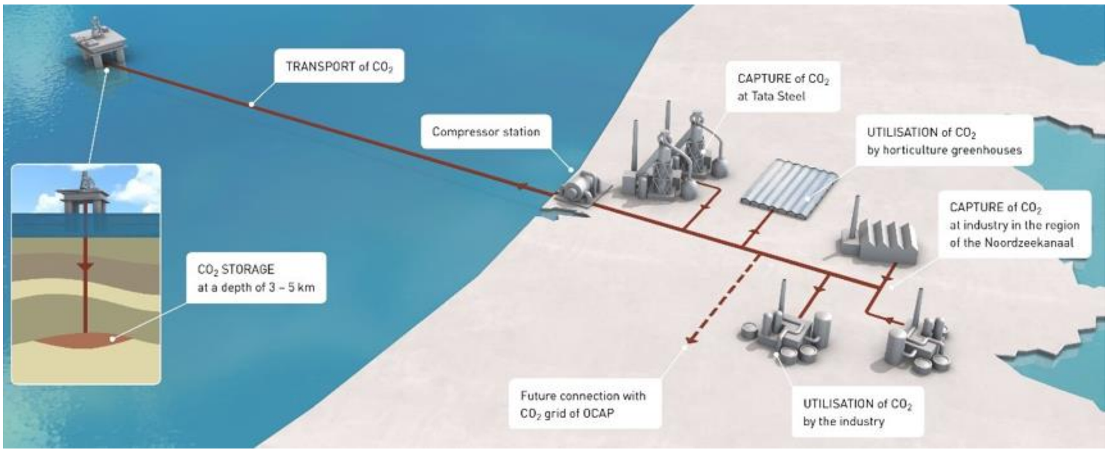

Figure 57: Athos project - CO_2 capture, transport, utilisation and storage[167]

Backbone pipelines provide the advantage of connecting multiple CO_2 emitting sources in a hub, as shown in Figure 57. A collective pipeline has the benefit of lowering the barrier to entry for individual emitters looking to access CCS infrastructure as they are not required to develop or maintain their own CO_2 transport and storage infrastructure. This also has the advantage of increasing the volume of CO_2 transported, increasing economies of scale.

[164] Seo et al 2016, Comparison of CO2 liquefaction pressures for ship-based carbon capture and storage (CCS) chain
[165] Peletiri et al 2018, CO_2 Pipeline Design: A Review
[166] Global CCS Institute 2020, Transporting CO_2
[167] CCUS Project Network 2020, ATHOS Consortium

Figure 58: Acorn CCS Project map[168]

CO_2 transport via pipeline is typically operated at pressures of 100-200 bar. This ensures that the CO_2 is maintained in the super critical phase during transportation and remains in a dense liquid state. Unlike hydrocarbons, CO_2 is not flammable or explosive and thus does not pose the same operational risks. Users must, however, manage the water content in the CO_2 stream to prevent corrosion or hydrate formation, which can damage the pipeline. The impact of impurities on pipelines is a current area of research and development.

It is also possible to utilise legacy oil and gas pipeline infrastructure for CO_2 transportation. This has the added benefit of significantly reducing the cost of pipeline transport, which is dominated by capital expenditure (CAPEX). Projects such as Acorn CCS, Scotland, are exploring this practice. This project will utilise the existing Goldeneye natural gas pipeline infrastructure to transport CO_2 from the St Fergus gas terminal approximately 100km offshore for storage in the North Sea. The Acorn CCS project map is shown in Figure 58.

Shipping

Shipping CO_2 has been operational at small scale for the past 30 years. Demand has primarily come from the food and beverage industries, with CO_2 transported on small ships. These small ships have capacities of less than 2,000 tCO_2. Significantly larger ships are required for commercial CCS applications. For example, a ship with a capacity of 10,000 tCO_2 is required for a project with a moderate flow rate of 1 $MtCO_2pa$[169].

CO_2 transport via shipping is a batch-like process, with ships operating individually, unlike the continuous transportation of CO_2 via pipeline. In a similar manner to pipeline transport, the CO_2 is liquefied before it is loaded onto the ship to increase cost effectiveness. If there is no ship available in the port, temporary storage is utilised. Temporary storage capacities of 100-150% of the ship's capacity are often quoted in literature. These also have the benefit of allowing a faster CO_2 transfer rate than the flow rate of the CO_2 source. This ensures that the ships can be used efficiently. Floating barges are commonly used as temporary storage facilities in hydrocarbon transport systems when onshore storage availability is limited.

[168] Offshore Energy 2020, Petrofac to support CCS and hydrogen project in UK
[169] Element Energy for BEIS 2018, Shipping CO_2 – UK Cost Estimation Study

From the temporary storage tanks, CO_2 is loaded onto the ship via a cargo handling system. Both cylindrical and spherical storage tanks are feasible for transporting CO_2 via ship, although the cylindrical tanks are proposed in most studies. The maximum size of each storage tank is heavily dependent on the chosen transport pressure. CO_2 transport pressure has a significant impact on all parts of the shipping chain. Transporting CO_2 at low pressure and temperature (5.2 bar and -56.6°C) when CO_2 coexists in all three phases (just above the triple point) is most cost effective. This is because CO_2 density decreases as the pressure approaches the critical point. There are three primary unloading options with the components of the CO_2 shipping chain shown in Figure 59.

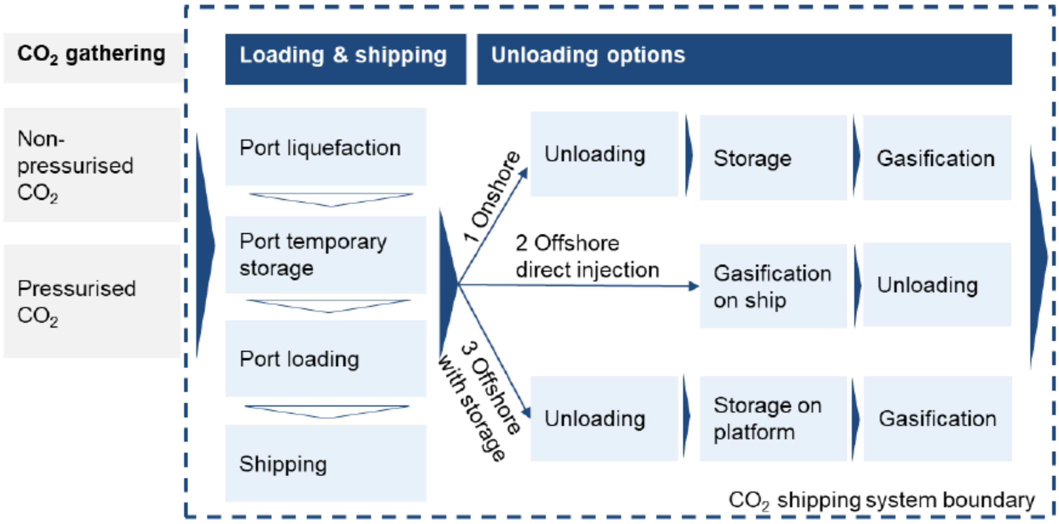

Figure 59: Components of the CO_2 shipping chain[169]

Although technically feasible, repurposing existing liquified natural gas (LNG) or LPG ships for CO_2 transportation is predicted to bring only minor cost reductions. This is because the ship CAPEX only forms a small portion (14%) of total shipping costs. Additionally, there would also be some capital requirement for converting the existing ship to a CO_2 transporting ship. This is likely to result in a sub-optimal transportation ship when compared to a purpose-built CO_2 transporting ship[169].

Road

Transporting CO_2 via road is currently only done for small scale applications. Typically, CO_2 is liquefied and stored in cryogenic vessels at a pressure of approximately 17 bar and a temperature of -30°C. Road transportation vessels are sized between 2-30 tonnes, allowing them to be towed via trucks as shown in Figure 60. As CO_2 transport via road is limited to small scale applications, it is not considered a suitable technology for CCS systems.

Figure 60: CO_2 transport via truck[170]

[170] ASCO 2021, Transportable CO_2 Tank

Rail

Transport of CO_2 via rail is currently only done in small batches where infrastructure already exists. Typically, CO_2 transport vessels are sized up to a capacity of 60 tonnes with a pressure of 26 bar. Although technically feasible, large-scale transport of CO_2 via rail is only considered a competitive option to a pipeline if existing rail infrastructure is already in place. Railways do not usually connect CO_2 emissions sources to large storage sites, so this is rarely the case.

Rail has been used to transport natural gas and LNG in remote areas where there is no connection to a natural gas grid. In the US, some states are not connected to gas grid or have insufficient capacity to meet demand. LNG transport via rail is being developed as an alternative in what is referred to as "virtual pipelines" with the government issuing the first permits in 2015[171]. An image showing vessels used to transport LNG via rail is shown below in Figure 61.

Because the feasibility of CO_2 transport via rail is heavily reliant on existing infrastructure, it is unlikely to be selected as the primary transport technology for CCS systems.

Figure 61: Transport of CO_2 vial rail would be similar to existing LNG rail transport shown above[172]

Economics

This report focuses on CO_2 transport via pipeline and ship as the most suitable technologies for transporting large quantities of CO_2 over large distances (often required for CCS). The benefits of each technology will vary by region and scenario. Some of the factors that have a significant impact on CO_2 transportation costs include the following:

- **CO_2 flow rate** – high pipeline flow rates typically reduce the cost per tonne of CO_2 stored. Larger ship capacities can also reduce the cost of shipping transport up to a volume of approximately 10,000 tCO_2.
- **Project duration** – longer project lifetimes favour CO_2 transport via pipeline due to the significant initial capital costs. Shipping is less CAPEX intensive and provides increased flexibility for shorter duration projects.
- **Transport distance and terrain** – pipelines are the most cost-effective method of transporting CO_2 onshore (unless terrain or routing is significantly challenging). Shipping is a more cost-effective method of transporting CO_2 over very large distances overseas.

In many cases, a combination of both shipping and CO_2 pipelines are used to maximise the benefits of each technology. This is the case for the Northern Lights CCS project in Norway where CO_2 will be captured and shipped over large distances to a central onshore facility. From this facility, CO_2 will be transported via an offshore pipeline to a permanent storage site in the North Sea. A schematic of this process is shown below in Figure 62.

[171] Congressional Research Service 2020, Rail Transportation of Liquefied Natural Gas: Safety and Regulation
[172] Railway Age 2020, USDOT Issues Rule Authorizing Bulk Transport of LNG by Rail

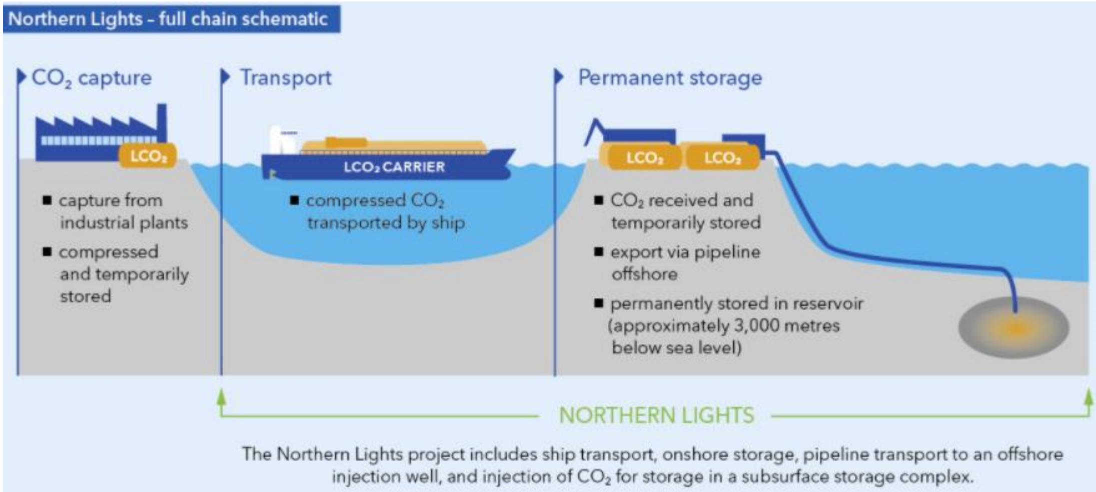

Figure 62: Northern Lights CCS chain schematic showing both shipping and pipeline transport[173]

The unit cost of CO_2 transport increases for both shipping and pipeline transport options. Transporting CO_2 via pipeline is more expensive than shipping over very large distances and short project durations due to the high CAPEX requirements of the pipeline infrastructure. This is shown below for CO_2 flow rates of 0.5 Mtpa and 5Mtpa in Figure 63. This shows that pipeline transport is more sensitive to changes in both distance and flow rate.

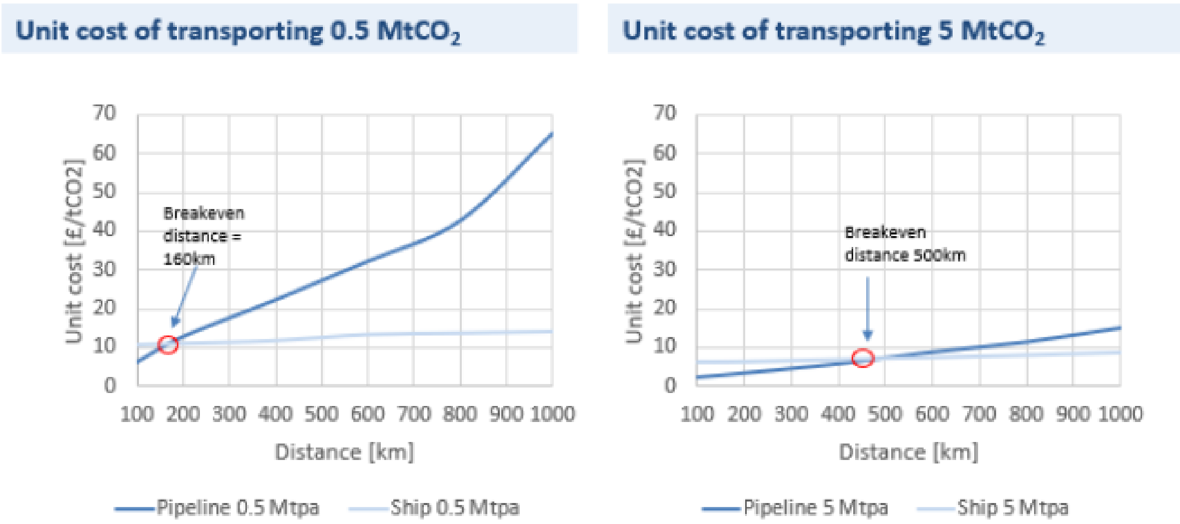

Figure 63: Breakeven distance of shipping for different flow rates. (Costs for newly constructed pipeline)[169]

4.3.2 CO_2 Storage

Geological storage utilises rock formations with pore space and sufficient permeability for CO_2 injection. Injected CO_2 is therefore able to flow through the underground reservoir and fill up the pore space. The storage site is secured by an impermeable rock formation known as the cap rock which prevents the CO_2 from migrating upwards into the atmosphere. Typically, CO_2 is compressed before injection into the reservoir to increase its density, therefore ensuring the CO_2 occupies a smaller pore volume, leading to more efficient storage. However, CO_2 phase behaviour can result in significant flow assurance challenges when injecting into sites at low pressure. This is typically the case in low-pressure depleted oil and gas fields where damage to well infrastructure could be caused by the rapid transition of CO_2 from the dense liquid state to the gas state[174,175].

[173] DNV GL 2020, Northern Lights show the way to seaborne CCS solutions
[174] Galic et al 2009, CO_2 Injection Into Depleted Gas Reservoirs
[175] Hoteit et al 2019, Assessment of CO_2 Injectivity During Sequestration in Depleted Gas Reservoirs

The reservoir must be at a depth of greater than 800m to ensure that the CO_2 remains in a dense liquid state. The injected CO_2 is stored permanently in the reservoir due to several mechanisms outlined below:

- **Structural trapping** – by the impermeable cap rock seal
- **Solubility trapping** – in pore space water
- **Residual trapping** – in both individual and groups of pores within the rock
- **Mineral trapping** – CO_2 reacts with rock to form carbonate minerals.

These CO_2 trapping mechanisms are dependent on the storage site geology with vast numbers of rock formations worldwide possessing the features required for CCS. The majority are found in vast geological features called sedimentary basins, whilst depleted oil and gas fields also have large capacities[12].

Oil and Gas Fields

Most of the oil and gas production is associated with large sedimentary basins. Oil and gas fields are identified as suitable permanent CO_2 storage sites as they have already demonstrated their ability to contain hydrocarbons and other fluids. Geological CO_2 storage utilises the same processes that have trapped hydrocarbons underground for millions of years. A map showing the reservoir capacity for CO_2 storage in oil and gas producing fields is shown in Figure 64.

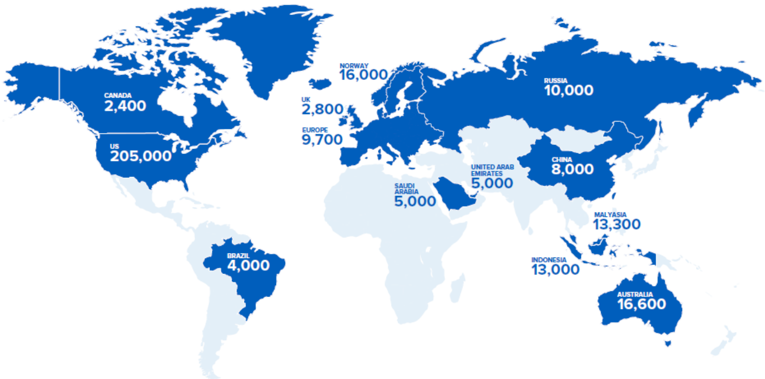

Figure 64: World map of CO_2 storage resources of major oil and gas fields (millions of tonnes)[12]

Storing CO_2 in geological formations is an advanced technology that has been used safely and effectively for decades with EOR operating commercially for over 40 years. EOR involves the injection of CO_2 into the oil field to enhance production. The injected CO_2 increases the overall pressure of the reservoir which results in a higher flow of oil towards the production wells. A schematic of this process is shown in Figure 65. The use of depleted oil and gas fields for CO_2 storage is often lower risk in terms of site characterisation as significant geological information is known through exploration in the oil and gas sector. Higher risks of CO_2 leakage may be associated with failure of legacy infrastructure e.g., well fractures.

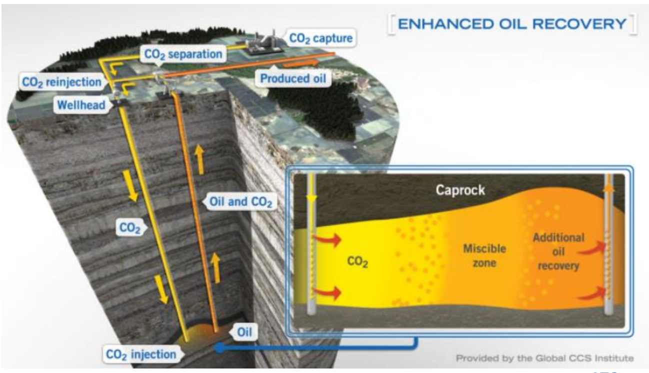

Figure 65: Enhanced oil recovery schematic[176]

[176] Global CCS Institute 2020, Storing carbon dioxide

Approximately 0.3-0.6 tCO_2 are injected in EOR processes per barrel of oil produced in the USA[177]. A portion of the injected CO_2 remains underground, whilst a significant quantity returns to the surface with the extracted oil. Typically, the CO_2 is removed from the oil stream and recycled so that it can be reinjected for further EOR. CO_2 storage rates greater than 99% can be achieved over the lifetime of a project. High capital costs of CO_2 infrastructure, unsuitable geology and limited availability of reliable sources of CO_2 feedstock in close proximity to oil producing fields have historically limited further deployment of EOR projects.

Saline Aquifers

Oil and gas fields have the capacity to meet the worlds CO_2 storage requirements. However, their geographic distribution is limited to certain regions of the globe as shown by Figure 64. Saline aquifers are significantly more common than oil and gas fields and their capacity for CO_2 storage is predicted to be hundreds of times larger. Current analysis predicts that 98% of world CO_2 storage resources are in saline formations[12]. CO_2 injected into deep saline formations will dissolve into the saline groundwater (brine) that is present in the aquifers. An example of this process is shown in Figure 66.

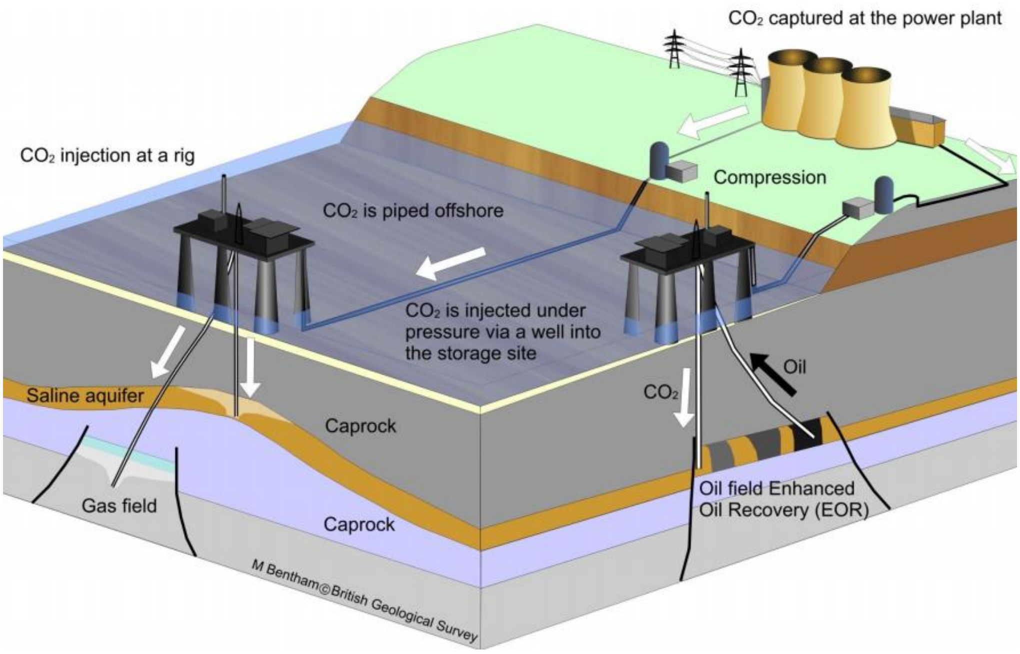

Figure 66: CO_2 storage in saline aquifers schematic[178]

Saline aquifers are at a disadvantage economically when compared to oil and gas fields as potential CO_2 storage sites. This is because they have historically had no (or very low) economic value and therefore there has been no investment into researching their potential for future CO_2 storage. Discovering suitable saline formations for CO_2 storage can be a costly and time-consuming process as it could take years to determine if a site is suitable for commercial CCS. The UK Storage Appraisal Project (UKSAP) is an example of a CO_2 storage appraisal database that has been developed to support more informed decision making on the opportunities from and economics of CO_2 storage. A map of this is shown in Figure 67.

As saline formations currently have limited economic value there is currently limited geological data about their potential for CO_2 storage available. The 45Q Tax Credit signed into US law in 2018 has promoted the utilisation of saline formations for CO_2 storage. Credits are worth \$50 per tonne of CO_2 stored in saline formations compared to \$35 per tonne of CO_2 stored for EOR.

Although saline aquifers may be plentiful in number and capacity, many will not be suitable as commercial storage sites. 'Open' saline aquifers are not laterally confined and therefore could lead to lateral CO_2 migration over several kilometres and increase the risks of leakage. Once injected, stored CO_2 requires monitoring to ensure it remains permanently contained. Sleipner CCS in Norway was the first commercial scale CCS project

[177] IEA 2020, CCUS in Clean Energy Transitions
[178] British Geological Survey 2010, CO_2 Storage in Saline Aquifers

with CO_2 injection commencing in 1996 into the Utsira Sand, a relatively shallow saline aquifer[179]. Approximately 1 million tonnes of CO_2 per year are stored under the North Sea which has been monitored by a combination of time-lapse seismic field monitoring and seabed surveys.

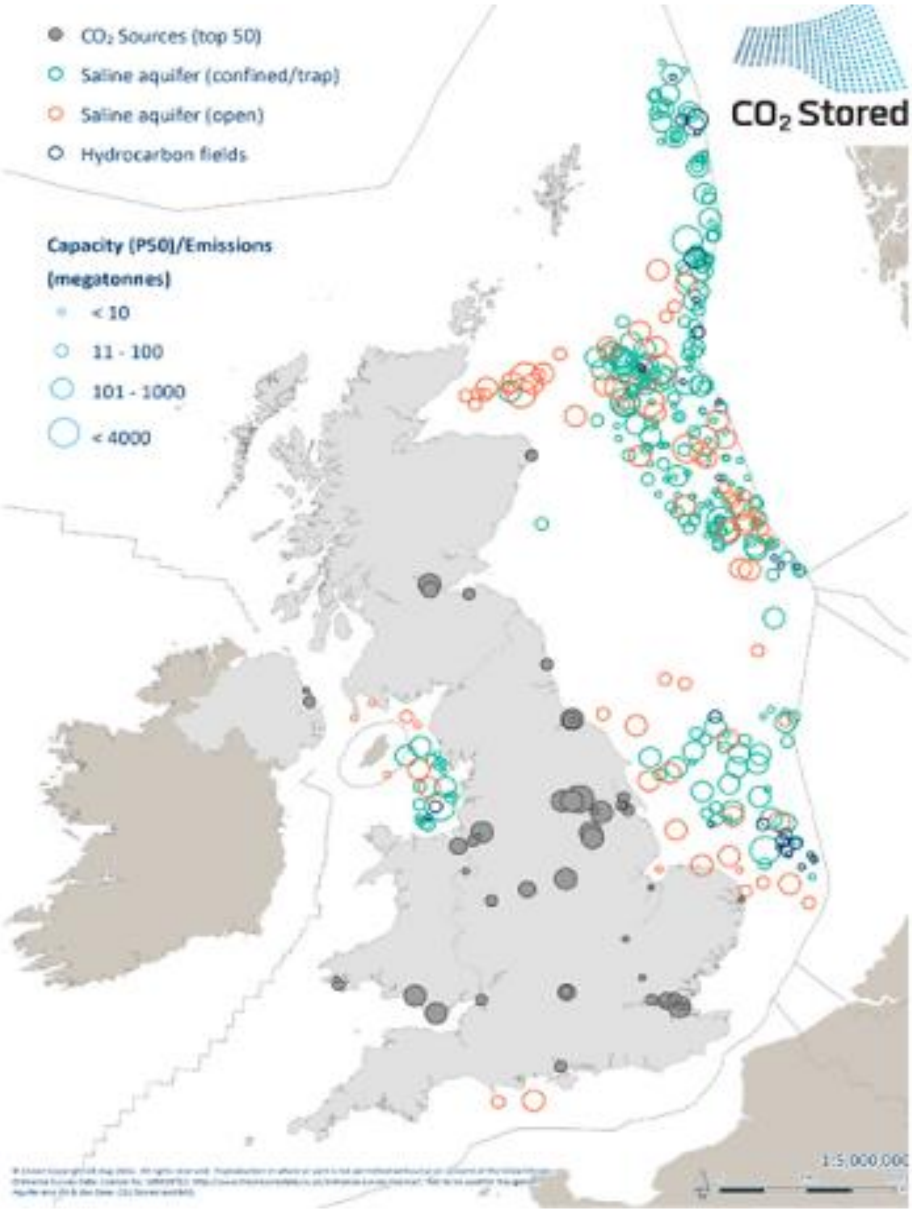

Figure 67: UK CO_2 storage estimation[180]

Storage Economics

The unit cost of storing CO_2 can decrease significantly when larger volumes are stored in a single storage facility. Economies of scale of larger storage sites are associated with both saline aquifers and depleted oil and gas fields, particularly offshore. In general, onshore CO_2 storage is cheaper than offshore as shown for storage costs in Europe by Figure 68. This also shows that utilising depleted oil and gas fields for CO_2 storage results in lower costs compared to saline aquifers. Although onshore CO_2 storage utilising depleted oil and gas fields is the cheapest storage configuration, it is also rare in comparison to the capacity of available saline aquifers. Furthermore, in some countries (e.g., Germany), on-shore CO_2 storage has significant public perception issues, and it is not permitted. Challenges and barriers limiting the deployment of blue hydrogen deployment are explored in Section 7.

[179] Chadwick, A and Eiken, O 2013, Offshore CO_2 Storage: Sleipner natural gas field beneath the North Sea
[180] British Geological Survey 2020, CO2 storage capacity estimation

Figure 68: Range of CO_2 storage costs in Europe by case[181]

The qualification of storage is cheaper and less time consuming for depleted oil and gas fields than it is for saline aquifers, primarily because there is significantly more available information. Major factors contributing to the cost of CO_2 storage are shown below:

- **Reservoir capacity** – larger reservoirs can benefit from economies of scale and therefore significantly lower costs of storage per tonne of CO_2 stored.
- **Legacy infrastructure** – utilising existing oil and gas infrastructure can result in significant cost savings (e.g., pipelines, floating offshore structure and wells). Saline aquifers require new infrastructure to be developed.
- **Field knowledge** – saline aquifers typically require greater site characterisation studies than depleted oil and gas fields.
- **Field location** – offshore CO_2 storage is typically higher cost than onshore.
- **Reservoir quality** – higher CO_2 injectivity ($MtCO_2$/year) reduces the cost of storage.
- **Monitoring, Measurement and Verification (MMV)** – includes the requirements across the storage lifecycle for monitoring CO_2 migration and validating containment. Monitoring wells are rarely drilled offshore due to the high-cost requirements. Indirect measurements from seismic surveys are often used.

MMV relies on a range of technologies for ensuring CO_2 containment, many of which have been developed by the oil and gas sector[182]. There is often a trade-off between using direct measurements in wells (which can be costly) and indirect measurements such as seismic surveys. For this reason, it is uncommon for monitoring wells to be drilled offshore whereas the use of seismic surveys has been demonstrated to be useful in monitoring the growth and migration of CO_2 plumes. Shared storage infrastructure allows for the benefit of distributing the cost of MMV across multiple CO_2 emitters. The Northern Lights project in Norway is pioneering the utilisation of shared storage infrastructure in the North Sea. This ensures individual emitters do not have to manage the risk and cost of qualifying and maintaining storage locations.

In addition, the economics of storage could be improved if coupled with EOR. The oil industry accounted for approximately 70-80$MtCO_2$ of consumption for EOR in 2017[177], primarily in the USA. Currently, between 0.3-0.6 tCO_2 is injected in EOR processes per barrel of oil produced in the USA. The majority of the CO_2 feedstock is produced from underground deposits, whereas less than 30% is sourced from industrial or large-scale emitters. This is primarily due to the fact that anthropogenic sources of emissions are not located in close proximity to producing oil fields. It is predicted that net emissions savings of approximately 0.5-1.5 tCO2 per tonne injected could be achieved through EOR utilising CO_2 from anthropogenic sources. Negative costs can be achieved in a small percentage of scenarios as shown for EOR cases in the USA by Figure 69.

[181] Zero Emissions Platform 2011, The Costs of CO_2 Capture, Transport and Storage
[182] DNV GL 2020, Potential for reduced costs for carbon capture, transport and storage value chains (CCS)

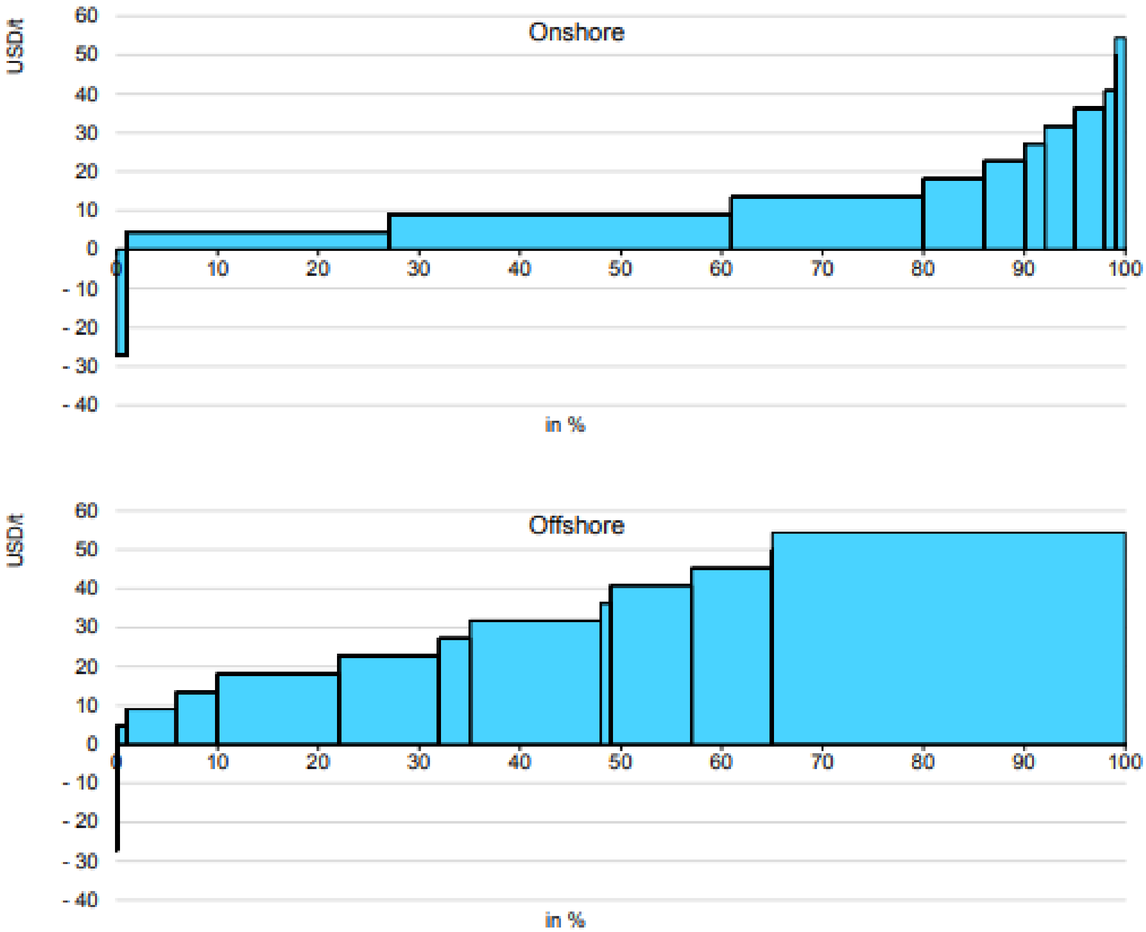

Figure 69: CO_2 storage cost curve for the US both onshore and offshore (%)[177]

4.3.3 Summary

Identifying regions where there are ongoing or planned CCS projects is a critical for the development of blue hydrogen production technologies. To reduce costs, it is important that these projects are part of wider cluster plans to ensure that economies of scale are achieved and that risks are shared between investors. It is clear from this analysis that there are many underground sites for CO_2 storage that should support the widespread deployment of blue hydrogen production technologies. However, further support is needed to develop these regions, particularly where there are large oil reserves for oil-based hydrogen.

4.4 Regional Case Studies

This section provides an overview of the potential for oil-based blue hydrogen production in five study regions. This includes case studies in all OPEC member countries as well as Brazil and the Netherlands. This considers CO_2 T&S options, feedstock availability and access to hydrogen markets. The research has informed the allocation of different blue hydrogen production technologies to each region, as well as the operation aspects modelled in the techno-economic analysis. This includes the location of hydrogen production and the type of T&S infrastructure used, hydrogen distribution technology choice and the routes for both hydrogen distribution and CO_2 T&S.

The five analysed regions and oil-producing case study countries are:

- Middle East – UAE, Saudi Arabia, Kuwait, Iraq, and Iran
- West Africa – Nigeria, Equatorial Guinea, Gabon, Republic of Congo, and Angola
- North Africa – Algeria and Libya
- Latin America – Brazil and Venezuela
- North Sea – Netherlands

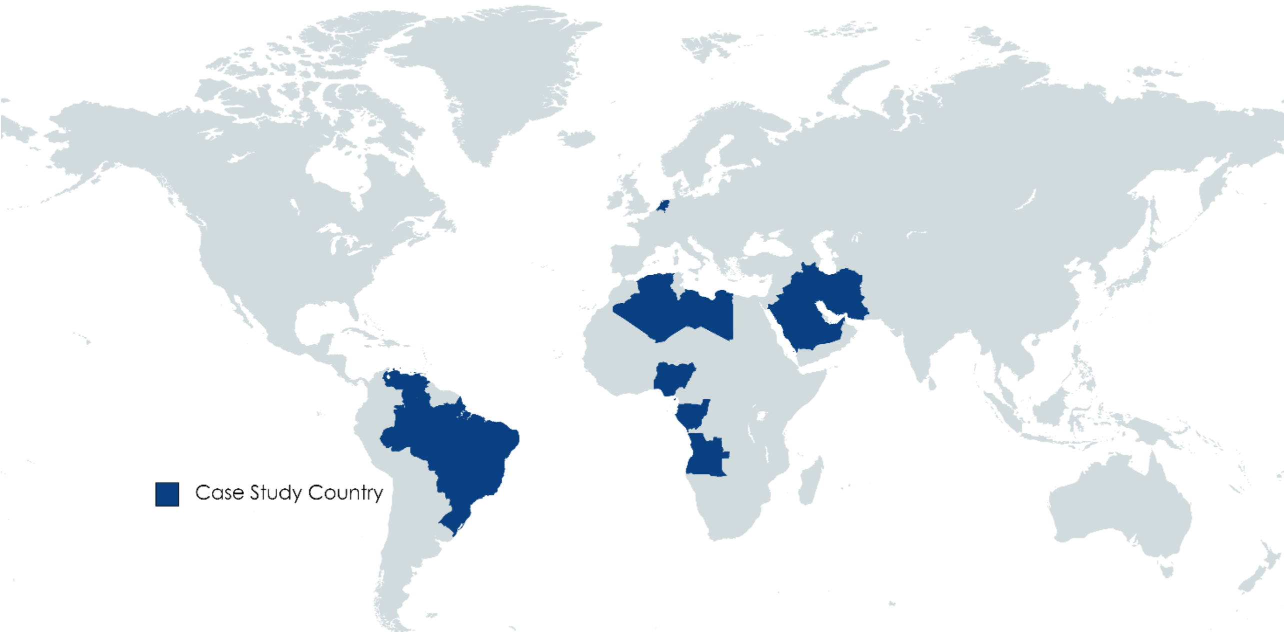

Figure 70: World map highlighting study regions and case study countries

4.4.1 Case Study Countries

The tables and supporting text below give a high-level summary of the considerations and conclusions from the regional analysis conducted in this section, including the rationale for choosing technology by country[183]. Within each of the regions previously described, there are several unknowns associated with economics of hydrogen distribution routes, favourable CO_2 T&S sites, and feedstock economics. This section describes the different hydrogen distribution and CO_2 T&S options available for each scenario that is then taken into the techno-economic analysis. Through this analysis, potentially lower-cost configurations are identified which can give regions direction on technology choices and target markets for hydrogen exportation.

- Table 5, Table 6 and Table 7 give an overview of the regional characteristics for the case study countries analysed.
- Table 8, Table 9 and Table 10 explore the uncertainties associated with the CO_2 T&S and hydrogen distribution infrastructure. Distances are given in the Appendices, Section 9.2.

[183] The attribution of technology to a country does not mean that the country can only use this process. Technology choice was aligned with infrastructure and feedstock availability, but was also chosen to ensure a balanced portfolio of technology options by region.

- Table 11, Table 12 and Table 13 highlight the hydrogen distribution options to high demand markets in the near future. Distances are given in the Appendices, Section 9.3.2.

Pipeline transport of CO_2 already exists or is currently in development in the North Sea, Middle East, and Latin America. In these regions, pipeline infrastructure development is likely to continue and may be combined with EOR projects. This has already been demonstrated at scale for projects including Port Arthur in Texas, Abu Dhabi CCS 1 and Santos Basin CCS in Brazil where pipeline infrastructure has been developed connecting emissions sources with geological storage. New CO_2 pipeline infrastructure and connections to yet-to-be-identified storage sites will be required for West Africa, North Africa, and Latin America. Connecting Algeria's coastal industrial regions to inland storage facilities (and legacy project) via pipelines is a likely option. There are currently no active or planned CCS projects in West Africa. Where HEE has been selected as the hydrogen production technology, CO_2 remains trapped underground during the production process; CCS infrastructure is not required. CO_2 storage sites are available in the form of depleted oil and gas fields and sedimentary basins for all case study countries. In the Middle East and North Africa, it is likely that storage sites will be located onshore, whereas offshore storage is likely to be developed in the Netherland, West Africa and Southeast of Brazil[12].

The hydrogen production facility location is an important consideration for all regions. In most cases it is likely that these facilities are developed in industrial regions where there is infrastructure to support international export and local hydrogen offtake from industry is available (as industrial regions are often located near ports). Locating hydrogen production facilities in industrial clusters leads to economies of scale if shared CCS infrastructure is developed. However, industrial clusters are not always located in close proximity to CO_2 storage sites (e.g., in Algeria where the former In Salah CCS project is located over 1,000km from the coastline).

Table 5: Regional overview for the Middle East

Country	Technology Analysed	Availability of T&S				Availability of oil feedstock	Likely transport routes for hydrogen exports in the short term
		Current/planned CCS projects	Legacy CCS projects	Storage availability (not under planning)	CO_2 T&S options		
UAE	SNR	Al-Reyadah capture approximately 0.8 $MtCO_2$/year from the Emirates Steel facilities.	Emirates Aluminum CCS.	CO_2 storage opportunities are likely to focus on the region's depleted oil and gas fields.	CO_2 pipeline to onshore storage in the ADNOC fields.	High – the UAE is the world's 7th largest holder of proved oil reserves.	Hydrogen exported via ship to Asia and Europe.
Iran	HEE	None.	None.	Storage appraisal required. Potential for development in onshore depleted oil and gas fields.	Proton Technology deployed – T&S not needed	High – Iran is the world's 3rd largest holder of proved oil reserves.	
Iraq	SNR	Peshkabir project captures 0.55 Mm^3/d of flared gas for EOR in the Tawke field.		Storage appraisal required. Potential for development in onshore depleted oil and gas fields.	CO_2 pipeline to local storage	High – The Rumaila oil field is the world's 3rd largest producing field in the world. Approximately 442,000 tonnes of Naphtha were produced in Iraq in industry in 2018.	
Kuwait	POX	None.		Potential for CO_2 storage development in depleted oil and gas fields as well as onshore sedimentary basins and saline aquifers.	CO_2 pipeline to local storage vs shipping to Saudi Arabia	High – Kuwait is the 10th largest oil producers in the world. The Al-Zour refinery will be the largest refinery in the Middle East in 2022.	
Saudi Arabia	POX	The Hawiyah gas processing facility captures 0.8 $MtCO_2$/year for storage in the Uthmaniyah field.		Large onshore sedimentary basins and depleted oil and gas fields. Significant potential but much of the region remains unexplored.	CO_2 pipeline to Uthmaniyah field.	High – Saudi Arabia contains the 2nd largest proved oil reserves in the world. The Ghawar field is the world's largest oil field in terms of production and total remaining reserves.	

Table 6: Regional overview for West Africa

Country	Technology Analysed	Availability of T&S: Current /planned CCS projects	Availability of T&S: Legacy CCS projects	Availability of T&S: Storage availability (not under planning)	Availability of T&S: CO_2 T&S options	Availability of oil feedstock	Likely transport routes for hydrogen exports in the short term
Nigeria	**HEE**	None.	None.	Storage appraisal required. Potential for development in depleted oil and gas fields surrounding the Niger River Delta.	Proton Technology deployed – T&S not needed.	High – Nigeria is the largest oil producer in Africa and is planning to increase refining capacity.	Hydrogen exported via ship to Europe and North America.
Republic of Congo	**POX**			Storage appraisal required. Potential for development in depleted oil and gas fields.	CO_2 pipeline to local storage.	High – The Republic of Congo is the 3rd largest oil producer in Sub-Saharan Africa and is planning to increase refining capacity.	
Equatorial Guinea	**HEE**			Storage appraisal required. Potential for development in depleted oil and gas fields surrounding Bioko Island.	Proton Technology deployed – T&S not needed.	Medium – significant crude oil capacity however there is currently no operational refining capacity.	
Gabon	**POX**			Storage appraisal required. Potential for development in depleted oil and gas fields.	CO_2 pipeline to local storage.	Medium – significant crude oil capacity however there is only one small refinery in operation.	
Angola	**SNR**			Potential for CO_2 storage development in depleted oil and gas fields as well as onshore sedimentary basins and saline aquifers.	CO_2 pipeline to local storage vs shipping to the Netherlands.	High – Angola is the second largest oil producer in Africa. The country has one operational refinery. However, it has significant plans for expansion.	

Table 7: Regional overview for North Africa, Latin America and the North Sea

Country	Technology Analysed	Availability of T&S: Current /planned CCS projects	Availability of T&S: Legacy CCS projects	Availability of T&S: Storage availability (not under planning)	Availability of T&S: CO_2 T&S options	Availability of oil feedstock	Likely transport routes for hydrogen exports in the short term
Algeria	**POX**	None.	The In Salah storage project injected CO_2 between 2004-2011 for enhanced gas recovery.	The Ahnet–Gourara sedimentary basin has been identified as those with the greatest potential for CO_2 storage.	CO_2 pipeline to local storage vs shipping to the Netherlands.	High - Algeria has significant proven onshore oil reserves with a proven capacity of 12.2 billion barrels in 2018.	Hydrogen exported via ship to Europe and North America.
Libya	**SNR**	None.	None.	Large onshore sedimentary basins and depleted oil and gas fields. Significant potential but much of the region remains unexplored.	CO_2 pipeline to local storage.	High – Libya contains the 9th largest proven oil reserves in the World.	
Brazil	**POX**	Commercial CCS is currently operational in the Santos basin in Brazil for EOR.	None.	Large sedimentary basins located both onshore and offshore in the south east of Brazil.	CO_2 pipeline to offshore storage in the Santos basin.	High – Brazil is the 10th largest oil-producing country in the world.	
Venezuela	**HEE**	None.	None.	Storage appraisal required. Potential for development in depleted oil and gas fields.	Proton Technology deployed – T&S not needed	High – Venezuela has the largest proved oil reserves in the world.	
Netherlands	**SNR**	Porthos, Athos, Hydrogen to Magnum	Buggenum carbon capture pilot (2011).	Potential for CO_2 storage in depleted oil and gas fields and saline aquifers.	CO_2 pipeline to offshore storage (Porthos).	High – Approximately 100 million tonnes of crude oil enters the port of Rotterdam per year.	Local use by industry – pipeline transport. Future grid blending

Table 8: CO_2 T&S and hydrogen distribution uncertainties for the Middle East

	UAE	Iran	Iraq	Kuwait	Saudi Arabia
CO_2 transport pathway	Pipeline to ADNOC fields (on-shore)	Proton Technology deployed – T&S not needed	CO_2 pipeline to local storage vs shipping to Saudi Arabia	CO_2 pipeline to local storage vs shipping to Saudi Arabia	CO_2 pipeline to Uthmaniyah field
T&S economies of scale (isolated vs cluster located production)	Significant – if collocated with existing CCS project(s) (Abu Dhabi, Uthmaniyah)	Proton Technology deployed – T&S not needed	Potential – in the long term. Industrial regions in Basra (South) and Baiji (North)	Potential – in the long term. Industrial region with surrounding Al Ahmadi.	Significant potential – Many regions identified in the National Industrial Cluster Development Program (NICDP)
H_2 transport options	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)

Mainly one option / lower uncertainty
Multiple options / higher uncertainty
Not applicable

Table 9: CO_2 T&S and hydrogen distribution uncertainties for West Africa

	Nigeria	Republic of Congo	Equatorial Guinea	Gabon	Angola
CO_2 transport pathway	Proton Technology deployed – T&S not needed	CO_2 pipeline to local storage vs shipping to the Netherlands	Proton Technology deployed – T&S not needed	CO_2 pipeline to local storage vs shipping to the Netherlands	CO_2 pipeline to local storage vs shipping to the Netherlands
T&S economies of scale (isolated vs cluster located production)	Proton Technology deployed – T&S not needed	Potential – in the long term. Small industrial sector in Pointe-Noire	Proton Technology deployed – T&S not needed	Potential – in the long term. Small industrial sector in Port-Gentil	Potential – in the long term. Industrial region with expanding refining capacity in Luanda
H_2 transport options	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)

Mainly one option / lower uncertainty
Multiple options / higher uncertainty
Not applicable

Table 10: CO_2 T&S and hydrogen distribution uncertainties for North Africa, Latin America and the North Sea

	Algeria	Libya	Brazil	Venezuela	Netherlands
CO_2 transport pathway	Pipeline infrastructure to newly developed CO_2 storage vs shipping to existing CCS clusters (North Sea)	CO_2 pipeline to local storage vs shipping to the Netherlands	Pipeline to offshore storage in the Santos basin	Proton Technology deployed – T&S not needed	Pipeline to nearby storage (off-shore)
T&S economies of scale (isolated vs cluster located production)	Potential – in the long term. Coastline industrial regions in Algeria (Arzew, Skikda)	Potential – in the long term. Industrial region surrounding Tripoli including refineries and cement plants	Potential – in the long term. Industrial regions in South East Brazil	Proton Technology deployed – T&S not needed	Significant – emerging CCS clusters around the North Sea (Rotterdam, Humber, Northern Lights)
H_2 transport options	Shipping for export over different distances (short term); potential local use- pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Shipping for export (short term) Potential local use in industry - pipeline (long term)	Local use by industry – pipeline transport. Future grid blending

Mainly one option / lower uncertainty
Multiple options / higher uncertainty
Not applicable

As mapped in Section 3, hydrogen demand is currently concentrated in Western Europe, North America, and Asia. The fastest growth is expected in these regions, and they are therefore identified as the primary export markets for this study in the near term.

Table 11: Hydrogen distribution route options for the Middle East

	UAE	Iran	Iraq	Kuwait	Saudi Arabia
Export Origin	Ruwais	Bandar Mahshahr	Basara	Mina Al-Ahmadi	Ras Tanura
Western Europe	• Shipping distance approximately 11,700km+ (via Suez canal)	• North Sea shipping distance approximately 12,250 km+ (via Suez canal)	• North Sea shipping distance approximately 12,300 km+ (via Suez canal)	• North Sea shipping distance approximately 12,150 km+ (via Suez canal)	• North Sea shipping distance approximately 11,900 km+ (via Suez canal)
North America	• East coast US shipping distance approximately 15,140km+ (via Suez canal) • West coast US shipping distance approximately 20,280km+ (via Suez & Panama canal)	• East coast US shipping distance approximately 18,500km+ (via Suez canal) • West coast US shipping distance approximately 20,750km+	• East coast US shipping distance approximately 18,600km+ (via Suez canal) • West coast US shipping distance approximately 20,800km+	• East coast US shipping distance approximately 18,500km+ (via Suez canal) • West coast US shipping distance approximately 20,700km+	• East coast US shipping distance approximately 18,250km+ (via Suez canal) • West coast US shipping distance approximately 20,500km+
Asia	• Shipping distance approximately 9,300-11,500km	• Shipping distance approximately 11,700km	• Shipping distance approximately 11,750km	• Shipping distance approximately 11,600km	• Shipping distance approximately 11,400km

Likely Longer distance – less likely Unlikely / NA

Table 12: Hydrogen distribution route options for West Africa

	Nigeria	Republic of Congo	Equatorial Guinea	Gabon	Angola
Export Origin	Lagos	Pointe-Noire	Malabo (Bioko Island)	Port-Gentil	Luanda
Western Europe	• Shipping distance approximately 7,700km+	• North Sea shipping distance approximately 8,800km+	• North Sea shipping distance approximately 8,300km+	• North Sea shipping distance approximately 8,400km+	• North Sea shipping distance approximately 9,200km+
North America	• East coast US shipping distance approximately 9,000km+ • West coast US shipping distance approximately 15,400km+ (via Panama canal)	• East coast US shipping distance approximately 10,500km+ • West coast US shipping distance approximately 16,400km+ (via Panama canal)	• East coast US shipping distance approximately 9,900km+ • West coast US shipping distance approximately 16,000km+ (via Panama canal)	• East coast US shipping distance approximately 10,000km+ • West coast US shipping distance approximately 16,000km+ (via Panama canal)	• East coast US shipping distance approximately 10,800km+ • West coast US shipping distance approximately 16,700km+ (via Panama canal)
Asia	• Shipping distance 19,300km (via Cape of Good Hope)	• Shipping distance approximately 18,100km+ (via Cape of Good Hope)	• Shipping distance approximately 19,200km+ (via Cape of Good Hope)	• Shipping distance approximately 18,700km+ (via Cape of Good Hope)	• Shipping distance approximately 18,000km+ (via Cape of Good Hope)

Likely Longer distance – less likely Unlikely / NA

Table 13: Hydrogen distribution route options for North Africa, Latin America and the North Sea

	Algeria	Libya	Brazil	Venezuela	Netherlands
Export Origin	Skikda	Tripoli	Santos	Puerto Jose	Rotterdam
Western Europe	• North Sea shipping distance approximately 3,000km+ (via Strait of Gibraltar) • Mediterranean shipping distance approximately 500-1,000km	• North Sea shipping distance approximately 3,500km+ (via Strait of Gibraltar)	• Shipping distance approximately 10,000km+	• North Sea shipping distance approximately 7,750 km+	• Potential local use / fed into European gas grid
North America	• East coast US shipping distance approximately 7,000km+ • West coast US shipping distance approximately 15,200km+ (via Panama canal)	• East coast US shipping distance approximately 9,100km+ • West coast US shipping distance approximately 16,000km+ (via Panama canal)	• East coast US shipping distance approximately 9,000km+ • West coast US shipping distance approximately 14,250km+ (via Panama canal)	• East coast US shipping distance approximately 4,000km+ • West coast US shipping distance approximately 7,900km+ (via Panama canal)	• East coast US shipping distance approximately 6,265km+ • West coast US shipping distance approximately 14,975km+ (via Panama canal)
Asia	• Shipping distance approximately 15,000-17,500km (via Suez canal)	• Shipping distance approximately 15,800km+ (via Suez canal)	• Shipping distance 21,000km (via Cape of Good Hope)	• Shipping distance approximately 17,000km+ (via Panama canal)	• Shipping distance approximately 19,900km (via Suez canal)

Likely Longer distance – less likely Unlikely / NA

4.4.2 Political Context

In many of the case study regions considered, fragile political situations may restrict or limit the potential for developing blue hydrogen production technologies. This is observed in the oil and gas industry where production is often at a fraction of total capacity due to military conflict, civil war, or infrastructure sabotage. Furthermore, sanctions placed on oil producing nations have significantly limited production in the oil and gas sector.

The political context for each country has not been considered in this analysis. However, further consideration for the suitability of developing oil-based blue hydrogen production technologies should be considered in future work, particularly in nations with less stable political situations.

4.4.3 Country profiles

The following section provides a profile for each country analysed. This outlines the potential for developing oil-based blue hydrogen technologies and considers the potential for developing CCS capabilities, availability of oil-based feedstocks and potential for hydrogen shipping exports.

In some regions, such as the UAE and Saudi Arabia, CCS projects are already operating commercially for EOR; CCS deployments are therefore more advanced. However, for many of the countries considered in this analysis there is yet to be any appraisal of the potential for developing CO_2 storage sites or capture facilities. In less developed CCS regions, knowledge accumulated from oil and gas exploration is likely to be utilised in any future developments.

UAE

CCS Projects[184]

Al-Reyadah launched the first large scale CCUS project in the Middle East in November 2016. CO_2 is captured from the Emirates Steel facilities in Abu Dhabi city and is transported for EOR in ADNOC's onshore fields. Approximately 0.8 $MtCO_2$/year is captured.

Potential Storage[185]

CO_2 storage opportunities are likely to focus on the region's depleted oil and gas fields. ADNOC are looking to expand their CCS capacity up to 5 $MtCO_2$/year by 2030 which is likely to focus on EOR projects.

Port infrastructure

The UAE has 12 major shipping ports located along both of its coastlines.

Oil Feedstock[186]

The UAE holds approximately 98 billion barrels of proved oil reserves, the 7th largest in the world. The majority of these reserves are located in Abu Dhabi (about 96% of the UAE's total). The UAE is also the world's 7th largest oil producer, with a production capacity of 4 million bbl/d.

Industry[187]

The UAE has five major refineries. Ruwais Refinery is the largest with a capacity of approximately 817,000 bbl/d. In 2018, over 14.7 million tonnes of naphtha were produced in the UAE. Phase 2 of the Al-Reyadah CCS project aims to develop a CO_2 T&S network in Abu Dhabi that will enable capture from additional emitters in the region.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. Plans to develop existing CO_2 T&S infrastructure network for future EOR. Potential for all three hydrogen production technologies to be developed.
Exports	Potential for long distance (c. 11,300 – 11,800km) shipping to access developing hydrogen markets in Asia and Western Europe (via the Suez Canal).

Iran

CCS Projects

None.

Potential Storage

A CO_2 storage study suggests Iran has a potential 70 $GtCO_2$ storage in saline aquifers with an additional 19 $GtCO_2$ from enhanced oil recovery.

Port infrastructure[188]

The oil terminal at Kharg Island accounts for 90% of Iran's oil crude oil exports. The Bandar Mahshahr port is an important exporting port for the Abadan refinery. Iran sent nearly all of its crude oil and condensate exports to China and Syria in 2020.

Oil Feedstock

Iran is the world's third-largest holder of proved oil reserves and second for natural gas. Ahvaz is the largest oil field in the country with an approximate capacity of 65 billion barrels.

Industry

Iran had 2.2 million bbl/d of refining capacity in 2019. The Abadan refinery, operated by the National Iranian Oil Refining and Distribution Company (NIORDC) is the largest operational with a capacity of 400,000 bbl/d.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is also significant potential to develop CCS infrastructure in depleted onshore fields. Potential for all three hydrogen production technologies to be developed.
Exports	Potential for long distance (c. 11,700 – 12,300km) shipping to access developing hydrogen markets in Asia and Western Europe (via the Suez Canal).

[184] Al Reyadah 2017, Case Study: Al Reyadah CCUS Project
[185] ADNOC 2021, Energy for Environment Protection
[186] Investopedia 2021, The Biggest Oil Producers in the Middle East
[187] EIA 2020, United Arab Emirates
[188] EIA 2021, Iran

Iraq

CCS Projects[189]
DNO's Peshkabir project captures 0.55 Mm^3/d of flared gas.
This is transported 80 km by pipeline to the Tawke field in the North of Iraq for enhanced oil recovery.

Potential Storage[190]
CO_2 storage opportunities are likely to focus on the region's depleted oil and gas fields.
Iraq could possess up to 25 $GtCO_2$ storage through enhanced oil recovery projects.

Port infrastructure
The Basra and Khor Al Amaya oil terminals are the primary oil exporting ports in Iraq.

Oil Feedstock[191]
Iraq holds 145 billion barrels of proved crude oil reserves, the fifth-largest in the world. The Rumaila oil field is the world's third largest producing field with a 1.5 million bbl/d capacity. It delivers approximately one-third of Iraq's total oil supply.

Industry
Iraq has a refining capacity of nearly 1.2 million bbl/d with an effective capacity of 900,000 bbl/d in 2021. Iraq's oil ministry expects the new 150,000 bbl/d Karbala refinery to come online in 2022. Approximately 442,000 tonnes of Naphtha were produced in Iraq in 2018.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is also significant potential to develop CCS infrastructure in depleted onshore fields. Potential for all three hydrogen production technologies to be developed.
Exports	Potential for long distance (c. 11,700 – 12,300km) shipping to access developing hydrogen markets in Asia and Western Europe (via the Suez canal).

Kuwait

CCS Projects
None.

Potential Storage[192]
CO_2 storage opportunities are likely to focus on the region's depleted oil and gas fields. The Kra Al-Maru field has been identified as a suitable location with as storage capacity of at least 440 $MtCO_2$.

Port infrastructure
Mina Al-Ahmadi is Kuwait's primary port for crude oil exports. Kuwait also has operational oil export terminals at Mina Abdullah, Shuaiba and Mina Saud.

Oil Feedstock[193]
Kuwait produced 2.7 million barrels of oil per day in 2020, making it the tenth largest oil producers in the world. Nearly all of Kuwait's crude oil production comes from onshore fields however there are plans to expand offshore production capacity.

Industry
Kuwait has a has two primary refineries (Mina Al-Ahmadi and Mina Abdullah) with a capacity of approximately 800,000 bbl/d. The Al-Zour refinery will be the largest refinery in the Middle East with a capacity of 615,000 bbl/d. Al Zour is expected to be fully operational in 2022.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is also significant potential to develop CCS infrastructure in depleted onshore fields. Potential for all three hydrogen production technologies to be developed.
Exports	Potential for long distance (c. 11,600 – 12,200km) shipping to access developing hydrogen markets in Asia and Western Europe (via the Suez Canal).

189 Journal of Petroleum Technology 2020, Gas Capture and Storage Program in Iraq Slashes Emissions
190 Kapsarc 2018, Enhanced Oil Recovery and CO_2 Storage Potential Outside North America: An Economic Assessment
191 EIA 2021, Iraq
192 Neele et al 2017, Options for CO_2 Sequestration in Kuwait
193 EIA 2016, Kuwait

Saudi Arabia

CCS Projects[12]

Saudi Aramco's Hawiyah natural gas production facility captures approximately 0.8 $MtCO_2$/year. This is transported 85km via pipeline and injected into the Uthmaniyah oil field for enhanced oil recovery.

Potential Storage[194]

An overview of oil and gas fields, as well as deep saline aquifer formations, suggests that there are significant CO_2 storage resources available in Saudi Arabia's sedimentary basins.

Port infrastructure

Saudi Arabia has four primary oil export terminals, providing access to the Red Sea and Persian Gulf. The port of Ras Tanura is the world's largest oil exporting port.

Oil Feedstock[195]

Saudi Arabia has 16% of the world's proved oil reserves, second only to Venezuela. Saudi Arabia produced over 11 million bbl/d in 2020. The giant Ghawar field is the world's largest oil field in terms of production and total remaining reserves.

Industry

Saudi Arabia has nine domestic refineries, with a combined capacity of 2.9 million bbl/d. The Ras Tanura refinery is the largest with a capacity of 550 bbl/d.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. Plans to develop existing CO_2 T&S infrastructure network for future EOR. Potential for all three hydrogen production technologies to be developed.
Exports	Potential for long distance (c. 11,400 – 12,000km) shipping to access developing hydrogen markets in Asia and Western Europe (via the Suez Canal). Shorter routes possible if H_2 shipping infrastructure is developed on the West Coast of the country.

[194] OGCI 2021, CCUS in Saudi Arabia
[195] EIA 2021, Saudi Arabia

Nigeria

CCS Projects
None.

Potential Storage
CO_2 storage opportunities are likely to focus on the region's offshore depleted oil and gas fields. Potential for geological CO_2 storage has also been identified in the Niger River Delta region.

Port infrastructure
Nigeria has six major seaports located along its coastline. Port Harcourt is the countries primary oil exporting port.

Oil Feedstock[196]
Nigeria is home to the second-largest proven oil reserves in Africa with approximately 37 billion barrels of proved reserves. Nigeria produced 2 million bbl/d in 2019 to rank as the 11th largest oil producer in the world. Investment in offshore exploration is increasing as the country has previously suffered from onshore pipeline sabotage.

Industry[197]
Nigeria currently has four oil refineries with a combined capacity of 445,000 bbl/d. The Dangote oil and gas refinery is currently in development and predicted to be operational by early 2021. The refinery will be the largest in Africa with a capacity of 650,000 bbl/d.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is potential to develop CCS infrastructure in depleted offshore fields, with some interest shown in EOR operations. Four industrial hubs have been identified with interest in developing future CCS infrastructure[198].
Exports	Potential for long distance (c. 8,200 – 11,500km) shipping to access developing hydrogen markets in Western Europe and North America.

Republic of Congo

CCS Projects
None.

Potential Storage[199]
CO_2 storage opportunities are likely to focus on the region's depleted oil and gas fields.

Port infrastructure
Pointe-Noire is the Republic of Congo's primary shipping port and container terminal. The Djeno terminal processes more than 95% of Congolese crude oil production.

Oil Feedstock[200]
The Republic of the Congo is the third–largest crude oil producer in Sub–Saharan Africa after Nigeria and Angola. The country's oil reserves are approximately 2.9 billion barrels.

Industry
The La Congolaise de Raffinage (CORAF) plant is The Republic of Congo's only refinery. Located in Pointe–Noire, the refinery has a capacity of 21,000 bbl/d. However, the Congolese government has reportedly signed a deal to develop a 110,000 bbl/d refinery in two phases at Pointe–Noire. This is more than a five-fold increase in capacity.

Blue H_2 Potential	Significant oil-based feedstock that could be utilised for blue hydrogen production. There is potential to develop CCS infrastructure in depleted offshore fields.
Exports	Potential for long distance (c. 8,800 – 10,500km) shipping to access developing hydrogen markets in Western Europe and North America.

[196] Investopedia 2021, The Main Oil Producing Countries in Africa
[197] EIA 2020, Nigeria
[198] IEA 2021, CCUS in Nigeria Workshop: Facilitating Nigeria's Energy Transition through CCUS Development
[199] Energy-pedia 2018, Congo (Brazzaville): NewAge to sell its stake in the Marine XII oil block, offshore the Republic of Congo
[200] EIA 2021, Congo-Brazzaville

Equatorial Guinea

CCS Projects
None.

Potential Storage[201]
CO_2 storage opportunities should focus on offshore activities. The Rio Muni basin, Okume and Ceiba oil fields, and the Zafiro and Alba oil and gas fields have been identified as those with the greatest potential for CO_2 storage development.

Port infrastructure[202]
Equatorial Guinea has two deep water ports (Malabo and Luba) located on Bioko Island dedicated to serving the oil and gas sector.

Oil Feedstock[203]
Equatorial Guinea has approximately 1.1 billion barrels of proven crude oil reserves. The offshore Zafiro field located West of Bioko Island, operated by ExxonMobil, is the country's largest source of oil output and export.

Industry
There are currently no refineries in Equatorial Guinea. A feasibility study for the development of the Punta Europa refinery on Bioko Island is currently underway with an FID expected in 2021.

Blue H_2 Potential	Significant oil-based feedstock that could be utilised for blue hydrogen production. There is potential to develop CCS infrastructure in depleted offshore fields.
Exports	Potential for long distance (c. 8,300 – 9,900km) shipping to access developing hydrogen markets in Western Europe and North America.

Gabon

CCS Projects
None.

Potential Storage[204]
CO_2 storage opportunities in Gabon are likely to focus primarily on the region's depleted oil and gas fields.

Port infrastructure
There are three major seaports located in Gabon (Port-Gentil, Libreville, Owendo) with oil terminals located in Gamba and Port-Gentil. Port-Gentil is the leading seaport in Gabon and centre for the petroleum industry.

Oil Feedstock[205]
Gabon is among the top five oil producers in sub-Saharan Africa and has 2 billion barrels of proved crude oil reserves. Gabon produced about 201,000 bbl/d of petroleum and other liquids in 2019.

Industry
The Sogara Refinery is Gabon's only refinery which is owned by Société Gabonaise de Raffinage (SOGARA). The refinery has a capacity of 24,000 bbl/d and is located in Port Gentil.

Blue H_2 Potential	Significant oil-based feedstock that could be utilised for blue hydrogen production. There is potential to develop CCS infrastructure in depleted offshore fields.
Exports	Potential for long distance (c. 8,400 – 10,000km) shipping to access developing hydrogen markets in Western Europe and North America.

[201] Global CCS Institute 2015, Carbon Capture and Storage in The Community of Portuguese Language Countries
[202] Oil and Gas Journal 2020, Equatorial Guinea advances Punta Europa refinery project
[203] EIA 2017, Equatorial Guinea
[204] World Oil 2015, G&G integration enhances acquisition of multi-client studies offshore Gabon
[205] EIA 2020, Gabon

Angola

CCS Projects
None.

Potential Storage[201]
Angola benefits from onshore sedimentary basins and offshore depleted oil and gas fields. Seven sedimentary basins are known in Angola. The Atlantic basins are currently being developed for oil and gas exploration. The onshore Kwanza basin contains deep saline aquifers identified as potentially suitable for CO_2 storage.

Port infrastructure[206]
Angola has four deep water ports (Luanda, Cabinda, Lobito and Namibe). Luanda is the primary shipping port.

Oil Feedstock[207]
Angola is the second largest oil producer in Africa with production focused offshore in the lower Congo basin region.

Industry
Luanda is the Angola's primary refinery with a capacity of approximately 65,000 bbl/d. Angola is planning to expand its refining capacity by developing refineries in Soyo, Cabinda, Lobito and an expansion to the existing Luanda refinery that are planned to be operational in the 2020's.

Blue H_2 Potential	Significant oil-based feedstock that could be utilised for blue hydrogen production. There is potential to develop CCS infrastructure in depleted offshore fields.
Exports	Potential for long distance (c. 9,200 – 10,800km) shipping to access developing hydrogen markets in Western Europe and North America.

[206] PWC 2013, Africa gearing up
[207] EIA 2021, Angola

Algeria

CCS Projects[208]

The In Salah storage project injected CO_2 produced from a collection of gas fields in central Algeria. Injection took place between 2004-2011 and was primarily for the purpose of enhanced gas recovery.

Potential Storage[209]

Several structures in the Ahnet–Gourara sedimentary basin have been identified as those with the greatest potential for CO_2 storage in Algeria.

Port infrastructure

Algeria has four major seaports located along its coastline. Arzew is the busiest port in terms of traffic and has been developed with a particular focus on petrochemical exports.

Oil Feedstock[210]

Algeria has significant proven onshore oil reserves with a proven capacity of 12.2 billion barrels in 2018. Plans for Algeria's first offshore exploration were announced in 2019. Algeria's crude oil, petroleum and other liquids production averaged over 1.6 million bb/d in 2017.

Industry

Algeria has five refineries with a total capacity of approximately 656,800 bbl/d. Skikda is the country's largest oil refinery and the 2nd largest refinery in Africa. Algeria's largest oil refineries are all located along its coastline with LNG export terminals operating in both the Arzew and Skikda ports.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is also significant potential to develop CCS infrastructure in depleted onshore fields. Potential for all three hydrogen production technologies to be developed.
Exports	Potential for long distance (c. 3,000 – 6,500km) shipping to access developing hydrogen markets in Western Europe and North America.

Libya

CCS Projects

None.

Potential Storage[211]

Libya has six large sedimentary basins with approximately 80% of recoverable oil reserves located in the Sirte basin. These basins are largely unexplored but there is likely to be significant potential for CO_2 storage development.

Port infrastructure

Libya has 15 operational ports many of which are developed for oil and gas exports.

Oil Feedstock[212]

Libya contains the largest proven reserves of oil in Africa and produced almost 1.2 million bbl/d in 2019.

Industry

Libya has five refineries with a combined crude oil distillation capacity of 378,000 bbl/d. The Zawiya refinery is the largest currently in operation with a capacity of 120,000 bbl/d.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is also significant potential to develop CCS infrastructure in depleted onshore fields. Potential for all three hydrogen production technologies to be developed.
Exports	Potential for long distance (c. 3,500 – 8,400km) shipping to access developing hydrogen markets in Western Europe and North America.

[208] The Christian Science Monitor 2014, Can we hide carbon dioxide underground? Algeria site offers note of caution.
[209] Aktouf and Bentellis 2016, CO_2 - storage assessment and effective capacity in Algeria
[210] EIA 2019, Algeria
[211] EIA 2015, Libya
[212] Investopedia 2021, The Main Oil Producing Countries in Africa

Brazil

CCS Projects[12]

A commercial CCS project is currently operational in the Santos basin in Brazil. CO_2 is captured offshore from a gas processing facility and injected for EOR.

Potential Storage[213]

There is significant potential for geological CO_2 storage in Brazil with the country benefiting from large sedimentary basins both onshore and offshore.

Port infrastructure

Santos is the largest port in Brazil and responsible for approximately 28% of trade. There is also an LNG terminal located in the Guanabara Bay in Rio de Janeiro.

Oil Feedstock[214]

Brazil has nearly 13 billion barrels in proven oil reserves, the second largest in Latin America after Venezuela. Brazil accounts for approximately 2.5 million bbl/d and is the 10th largest oil-producing country in the world. Approximately 94% of proven oil reserves in Brazil are located offshore, with the Campos basin accounting for 76% production.

Industry

There are 17 refineries in Brazil with a total capacity of 2.4 million barrels per day. The Replan refinery located in Sau Paulo is the largest refinery in the country with a capacity of approximately 434,000 bbl /d in 2019.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is also significant potential to develop CO_2 storage in depleted offshore fields.
Exports	Potential for long distance (c. 9,100 – 10,100km) shipping to access developing hydrogen markets in North America and Western Europe.

Venezuela

CCS Projects

None.

Potential Storage

CO_2 storage opportunities are likely to focus on the region's depleted oil and gas fields.

Port infrastructure

Venezuela has 5 major seaports. Puerto Cabello is the largest port in Venezuela and is known for its importance in the oil industry. However, in 2019 almost 90% of crude oil was exported from Puerto Jose.

Oil Feedstock[215]

In 2020, Venezuela had 303 billion barrels of proved oil reserves, the largest in the world. The Maracaibo basin is the primary oil producing region, representing almost half of Venezuela's oil production. Venezuela also contains billions of barrels in extra-heavy crude oil and bitumen deposits, most of which are situated in the Orinoco Belt.

Industry[216]

Venezuela had 1.3 million bbl/d of refining capacity in 2019, operated by the state owned Petróleos de Venezuela, S.A (PdVSA). However, actual refining throughput in 2019 was estimated to be at 10% of capacity.

Blue H_2 Potential	Abundance of oil-based feedstock that could be utilised for blue hydrogen production. There is also significant potential to develop CO_2 storage in depleted onshore fields.
Exports	Potential for long distance (c. 3,500 – 8,400km) shipping to access developing hydrogen markets in Western Europe and North America.

213 CEPAC 2015, Brazilian Atlas of CO_2 Capture and Geological Storage
214 EIA 2021, Brazil
215 Investopedia 2019, The Biggest Oil Producers in Latin America
216 EIA 2020, Venezuela

Netherlands

CCS Projects[119]

The Netherlands is developing large scale offshore CCS projects in Rotterdam (Porthos) and Amsterdam (Athos) that will capture CO_2 from industrial clusters that will be stored in the North Sea.

Potential Storage[180]

The North Sea has excellent CO_2 storage facilities, benefiting from both depleted oil and gas fields as well as saline aquifers.

Port infrastructure

There are five major seaports in the Netherlands. Rotterdam is the largest port in Europe.

Oil Feedstock[217, 218]

In 2019, oil production in the North Sea accounted for approximately 3 4% of global production. Approximately 100 million tonnes of crude oil enters the port of Rotterdam per year, with the majority destined for use in the port's refineries. The Netherlands has a refining capacity of over 1.2 million bbl/d.

Industry[219]

There are over 120 industrial companies operating in the port of Rotterdam cluster, with a total of five refineries. In 2018, over 11.5 million tonnes of Naphtha were produced in the Netherlands.

Blue H_2 Potential	The Netherlands imports significant volumes of oil feedstocks that could be utilised for blue hydrogen production. A network of CO_2 T&S infrastructure is also being developed in the country's industrial clusters, with captured CO_2 to be stored in under the North Sea.
Exports	Hydrogen production in the Netherlands is likely to be consumed locally. Initially by the industrial sector, with future growth forecast in the heat, transport and power sectors.

217 EIA 2016, Netherlands
218 S&P Global 2020, UK North Sea oil production to be maintained as industry moves to 'minimal manning' offshore: OGUK
219 Port of Rotterdam 2016, Industry in the Port

5 Techno-economic Assessment

As demonstrated in Section 3, there is a significant opportunity for hydrogen in a decarbonised energy future. Hydrogen production from oil has the potential to be a major contributor in delivering this hydrogen supply, particularly in large CCS clusters. In regions with more advanced hydrogen strategies (highlighted in Section 3.4), oil-based blue hydrogen production can potentially play a role due the opportunities from scale and utilisation of existing oil and gas infrastructure. It is therefore important to consider different technologies as well as production from different regions to determine relative competitiveness and the potential market access for hydrogen derived from oil.

This analysis explores the production of hydrogen from oil and oil-based products in fifteen countries, as described in Section 4.4. The modelling considers; technology capital and operational costs; feedstock, electricity, fuel, and carbon prices; and CO_2 T&S and hydrogen distribution infrastructure.

This results in a LCOH for each region in a series of different cases and sensitivities.

5.1 Key Sensitivities and Methodology

5.1.1 Technoeconomic Assessment Methodology

This section outlines the key inputs and associated sensitivities for the techno-economic analysis. The model used in this analysis uses the assumptions specified throughout this section and listed in the Appendices (Section 9). The primary outputs are the LCOH and cost of CO_2 abatement.

Cost and Emissions Gateways

There are three hydrogen cost gateways in this study, as shown in Figure 71.

- **Gateway 1** only considers the hydrogen production facility and hydrogen compression.
- **Gateway 2** includes the hydrogen production facility, compression, and the CO_2 T&S infrastructure.
- **Gateway 3** includes the entire value chain up to the point of end use.

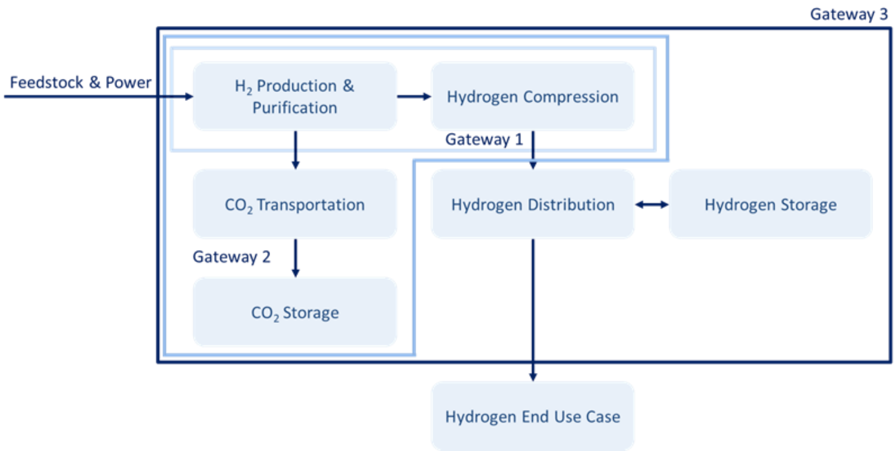

Figure 71: Model cost and emission gateways

Levelised Cost of Hydrogen

The techno-economic model uses a cash flow to determine the LCOH and is calculated at the three different gateways, defined in Figure 71. This equation is shown below with the subscript denoting the gateway. This is the price that is necessary over the lifetime of the asset to give a zero net present value.

$$LCOH_n = \frac{|Net\ Present\ Expenditure_n|}{Net\ Present\ H_2\ Production}$$

The following definitions are used throughout this analysis:

- **Net Present Expenditure** is the sum of the discounted cost of the feedstock, fuel, electricity, carbon price, capital, operations, CO_2 T&S fee and hydrogen distribution and storage fee, subtracted by revenue[220] generation over the asset's lifetime.
- **Net Present H_2 Production** is the sum of the discounted production of hydrogen over the asset's lifetime.

The model uses cost trajectories from 2020 as inputs for:

- Cost of feedstock, fuel, and electricity
- Carbon price
- Grid carbon intensity

The assumptions to support these trends are described in this section and in the Appendices, Section 9.3.

Modelling Parameters

For consistency with other IEAGHG studies, the same techno-economic parameters are used where possible.

- **Discount Factor –** A standard discount rate of 8% is used throughout this analysis. Sensitivities of 10% and 5% are explored in Figure 72.
- **Asset Lifetime –** A standard plant operating life of 25 years is used throughout this analysis. A plant life of 40 years was not considered due to uncertainties over variable fuel and feedstock trajectories.
- **Currency –** economic outputs and costs are presented in Euros in order to align with data collection. Where data was taken from previous years, inflation was accounted for. A conversion rate of \$1.142/€[221] and €1.1248/£[222] was used, taken as the average exchange rates in 2020.

This study explored the impact of discount factors of 5.0%, 8.0% and 10.0% on the LCOH, as shown for the central case for partial oxidation in Saudi Arabia in Figure 72. This figure shows that the range of discount factors considered has a small impact on the levelised cost of hydrogen in this study[223].

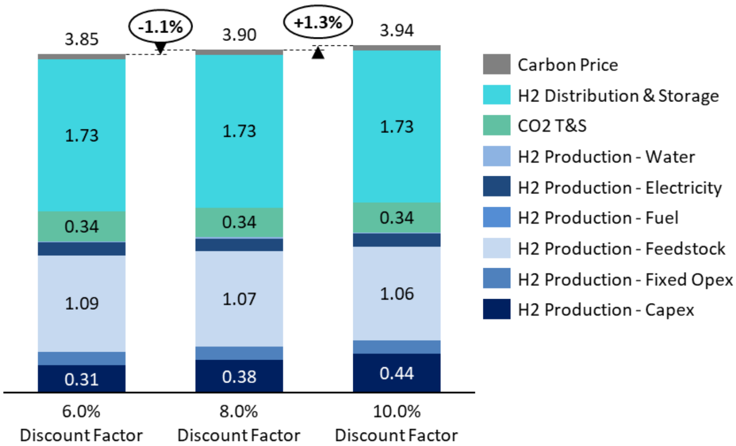

Figure 72: Levelised cost of hydrogen for partial oxidation (TRL 9) in the Saudi Arabia central case for varying discount factors in 2020 (€ / kgH_2)

Technology Readiness Levels

Two of the three oil-based hydrogen production technologies analysed in this report have a TRL of 9. These are SNR and POX. HEE has a lower TRL of 4-6, however, Proton Technologies aspires to advance their HEE process as they licence their technology. Information on HEE was significantly dependent on Element Energy's

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221 Exchange Rates 2021, Euro to US Dollar Spot Exchange Rates for 2020
222 Exchange Rates 2021, British Pound to Euro Spot Exchange Rates for 2020
223 The cost of water in this and all figures is near zero. The same is true for power export for SMR without CCS. Further details on cost components is given in the Appendices, Section **Error! Reference source not found.**. There are no fuel costs for partial oxidation and therefore none shown in this figure.

bottom-up analysis (outlined in Section 9.3.1) and is therefore less reliable. This report therefore highlights in comparative analyses the respective TRLs for each technology.

Sensitivity

For each variable, either a range of values, giving a maximum and minimum, or a single value were collected. Where a range of values have been collected, the sensitivity analysis uses Tornado Plots to show the possible range of costs and/or emissions. Where this range is less than +/-10%, a sensitivity of +/-10% is applied to show greater variation. Where only a single value has been found, the cost component / emissions is varied by +/-10% in the Tornado Plots to demonstrate the impact on the LCOH and cost of CO_2 abatement. Sensitivities for each country are presented in the Appendix (Section 9.6.1).

Reference Case

To compare with the incumbent, the Base Case from IEAGHG's 'Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS'[38] study was used. This configuration does not include CCS however, a PSA is used to increase hydrogen purity and excess steam is exported for power generation. This is based on production in the Netherlands with process data displayed for this technology in the Appendices, Section 9.2.

Presentation of Data

There are three ways in which the LCOH for each scenario is presented:

- **Stacked Bar Charts -** The LCOH is broken down by cost component up to Gateway 3.
- **Tornado Plot -** The range of costs for each cost component in the base case is shown, based on the specified data range. The list of components is the same as those in Gateway 3.

The cost of CO_2 abatement is also considered at Gateway 1.

Production Facility Capacity

All case studies are based on a 300MW$_{LHV}$ (79 ktonnes/year) hydrogen production facility at a 100% load factor. This capacity is comparable with other gas-based hydrogen production facilities identified in literature as shown in Figure 73 and ensures that different case studies are comparable. As dedicated hydrogen production from oil is yet to be fully commercialised, comparable capacities were not found in literature.

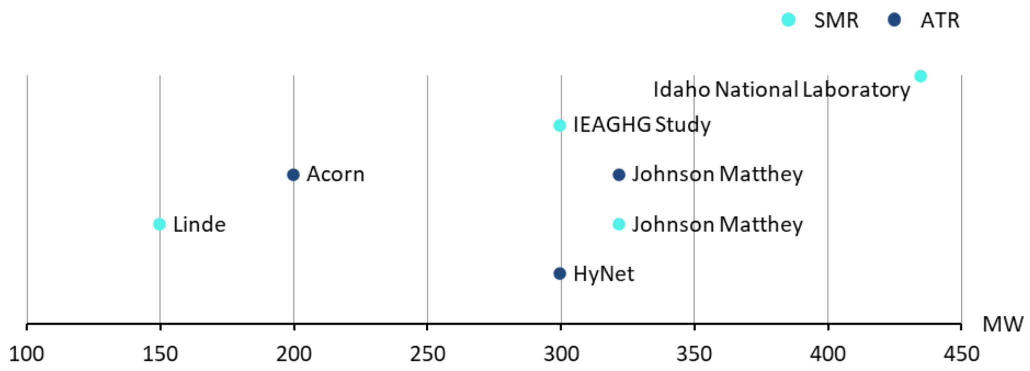

Figure 73: Natural gas based blue hydrogen production capacity[224]

5.1.2 CAPEX and Fixed OPEX

Capital Expenditures (CAPEX) and fixed operational expenditure (OPEX) estimates for this techno-economic study have arisen from literature and stakeholder engagement. The assumptions are shown in the Appendices, Section 9.3.1 and central values are shown for all oil-based technologies in Table 14. POX and SNR data is based on mature technology with CAPEX and OPEX costs scaled to a 300MW hydrogen production facility. The HEE data is based on Element Energy's bottom-up analysis that utilises commercial data where available. CAPEX and OPEX costs for HEE are predicted to be significantly cheaper than the POX and SNR processes

[224] SMR gas based blue hydrogen has been deployed successfully in industry, whilst ATR gas based blue hydrogen is in advanced stages of design development.

as hydrogen producing reactions occur underground and the process does not require a reformer as part of the configuration. Furthermore, the HEE process utilises hydrogen produced onsite (in the base case) to generate electricity that is utilised to run all auxiliary processes and there are no costs associated with CO_2 T&S.

Table 14: Technology CAPEX and Fixed OPEX for a 300MW production facility - Central Case[225]

Technology	CAPEX – Central Case [€ / kW_{LHV}]	Fixed OPEX – Central Case [€ / kW_{LHV} / yr]
Partial Oxidation	1,040	40.0
Steam Naphtha Reforming	1,030	36.0
Hygenic Earth Energy	600 / 700	23 / 27

As far as is possible based on literature reviews and stakeholder engagement, the definition for the CAPEX and fixed OPEX by technology has been maintained to facilitate comparable analysis.

Where data is not available for fixed OPEX, a flat rate was used. This is based on the average of those rates for technologies where there is sufficient data. This was found to be 3.9% the value of the technology CAPEX and varies between 5.2% and 3%.

Steam Naphtha Reforming

Data on both the CAPEX and fixed OPEX for SNR uses SMR as a proxy. This is due to a) the limited information about costs associated with SNR and b) the close alignment between the two processes. The main sources of information are H21 North of England[226] and IEAGHG[38]. Particularly, the IEAGHG case includes a pre-reformer which is needed for SNR. The range in CAPEX data is less than +/- 10% and so a sensitivity of 10% is used in this analysis[227].

The fixed OPEX is based on detailed estimates from IEAGHG's Techno-economic Evaluation of SMR (Case 3 for the CCS case and the Base Case for the Reference Case) and H21 North of England's Report. The IEAGHG paper and the H21 North of England report (assuming the SMR fixed OPEX has the same cost components as the ATR in the report) both include direct labour, maintenance, and operations/overheads. There are some differences between the sources, but the fixed OPEX spans a range of 3% to 3.9% of CAPEX, demonstrating close alignment. The range in fixed OPEX is +/- 17.1%.

Partial Oxidation

Data on the POX CAPEX is limited. The bound of costs shown on the Appendices is based on information from stakeholder engagement and proxies from literature, such as the University of Florida[228]. This report recognises the associated uncertainties around this capital cost and highlights these in the Appendices. The range in CAPEX is less than +/- 10% and so a sensitivity of 10% is used in this analysis.

For the fixed OPEX, the flat rate of 3.9% of CAPEX is used. As a result, the range in fixed OPEX follows that of the CAPEX; +/- 10%.

Hygenic Earth Energy

Two primary CAPEX scenarios are explored for this process; in both cases the sensitivity is +/- 10%.

- Scenario 1 assumes that the process is used at a depleted reservoir. The well cost is therefore near zero as existing infrastructure is used. The only capital cost components are the membrane, air separation unit and hydrogen generator.

[225] CAPEX data was not regionalised in this study
[226] H21 North of England 2018, H21 North of England Report
[227] The range used here does not represent the uncertainty in the figure itself, but the fact that the range of data collected from literature / stakeholders was less than 10%. In this instance, the sensitivity analysis considers a 10% deviation in CAPEX.
[228] Mirabal, S 2003, An Economic Analysis of Hydrogen Production Technologies Using Renewable Energy Resources

- Scenario 2 assumes that the operator pays to drill a new well on top of the other items of capital equipment.

A sensitivity is also considered where the site is powered by the grid instead of the hydrogen turbine. This simply removes the cost of the hydrogen turbine. The bottom-up costing methodology is presented in the Appendices, Section 9.3.1.

For the fixed OPEX, the flat rate of 3.9% of CAPEX is used. As a result, the range in fixed OPEX follows that of the CAPEX; +/- 10%.

5.1.3 Feedstock, Fuel and Electricity

Oil Price

There is significant variation found in oil price forecasts in literature. The majority of forecasts from oil majors are found to lie within the bounds of the EIA's International Energy Outlook 2019[229] "Low Oil Price" and "Reference Oil Price", as displayed in Figure 74. The oil major forecasts displayed below were made before July 2020 and reflect their expectations for end of 2020 out to 2050[230]. This captures the impact of Covid-19.

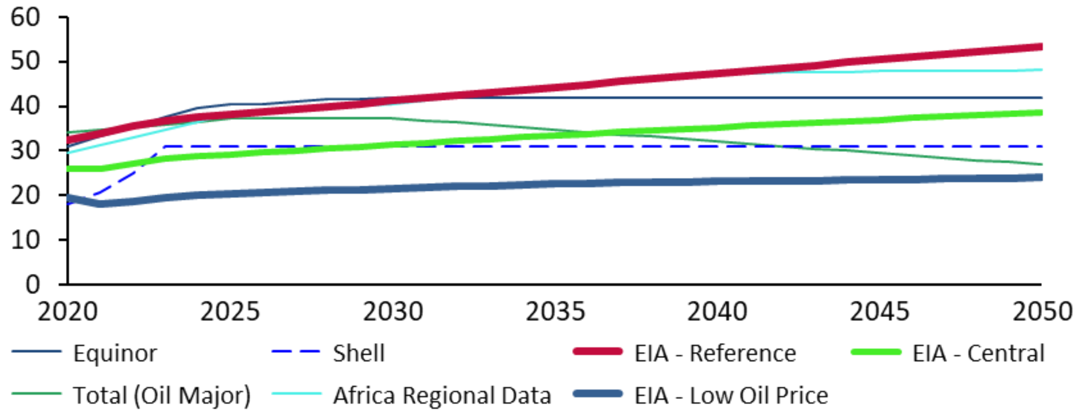

Figure 74: Oil price forecast comparison (€ / MWh)

The EIA's "Low Oil Price" and "Reference Oil Price" are used as the minimum and maximum bounds for our sensitivity for all regions. The central case is the average of these two trends. The EIA's "High Oil Price" is not included as the high oil price does not make the business case for oil-based H_2 production viable.

Vacuum Residue

Two sensitivities for the price of vacuum residue are considered.

- The first sensitivity assumes that the price of the vacuum residue is the same as the price of oil and uses the same data range.
- The second case values the feedstock as a waste product, i.e., €0.00/MWh, significantly improving the business case.

Natural Gas and Electricity Prices

Regional prices for electricity and natural gas for 2020 have been taken from literature. Regional trends out to 2050 are used where available. Where these are not available, global forecasts are applied to regional prices. This is presented in the Appendices, Section 9.3.3.

Naphtha

The price of naphtha varies significantly by region. In this analysis, the price forecast is indexed against the price of oil.

[229] EIA 2019, International Energy Outlook 2019
[230] S&P Global 2020, Eni cuts long-term oil price assumption to $60/b on coronavirus

- **Netherlands –** Low-cost case based on international market price for naphtha in 2020[231] (€39.45/MWh) and the high-cost case is based on regional data from ICIS[232] (€79.82/MWh).
- **UAE –** Low-cost case based on Ruwais refinery data for naphtha in 2020[233] (€1.98/MWh) and the high-cost case is based on the international market price for naphtha in 2020 (€39.45/MWh).
- **Libya, Angola and Iraq –** The central case is based on the international market price for naphtha in 2020 (€39.45/MWh), with 10% sensitivities analysed for low and high cost cases.

Steam and Water

Steam and water are also important to produce hydrogen from SNR and POX technologies. The impact of the cost of water was tested on the SNR case. Assuming that the water is priced as the same as the NREL model[234] at €0.0018/kg water, and that the power input into the system is sufficient to generate steam, the inclusion of steam increases the Gateway 3 LCOH by less than €0.001/kg or 0.02%. Cooling water is not costed in this analysis.

5.1.4 Carbon Pricing

A carbon price is a critical tool for supporting the uptake of low carbon technologies. Carbon prices are applied at the regional level where information is available for the Netherlands. Where information is not available, international trends are used instead. This is provided by the World Energy Council[235] and BP Energy Outlook 2020[236]. Carbon price forecasts for all study regions are shown in Figure 75. This shows three carbon price forecasts, with the carbon price applied to the Netherlands the highest in this study.

The carbon price forecasts for each region were developed with the following assumptions:

Netherlands

- Min – Average of BP 'Rapid and Net Zero (Emerging)' and World Energy Council 'Jazz' regional scenarios.
- Max – BP 'Rapid and Net Zero (Developed)'.

UAE, Kuwait, and Saudi Arabia

- Min – Average of BP 'Rapid and Net Zero (Emerging)' and World Energy Council 'Jazz' regional scenarios.
- Max – Average of BP 'Rapid and Net Zero (Developed)' and World Energy Council 'Symphony' regional scenarios.

All other regions

- Min – Average of BP 'Business as Usual (Emerging)' and World Energy Council 'Jazz' regional scenarios.
- Max – Average of BP 'Business as Usual (Developed)' and World Energy Council 'Symphony' regional scenarios.

The central forecast for all regions is the average of the 'min' and 'max' forecasts.

231 Statista 2021, Price of naphtha worldwide from 2017 to 2021
232 ICIS 2018, Europe hexane prices up naphtha solvent and white spirit down on feedstocks
233 Zawya 2019, ADNOC sets H1 2020 naphtha offers at 81-108% higher vs FY 2019
234 NREL 2018, H2A: Hydrogen Analysis Production Models
235 World Energy Council 2013, World Energy Scenarios
236 BP 2020, Energy Outlook 2020

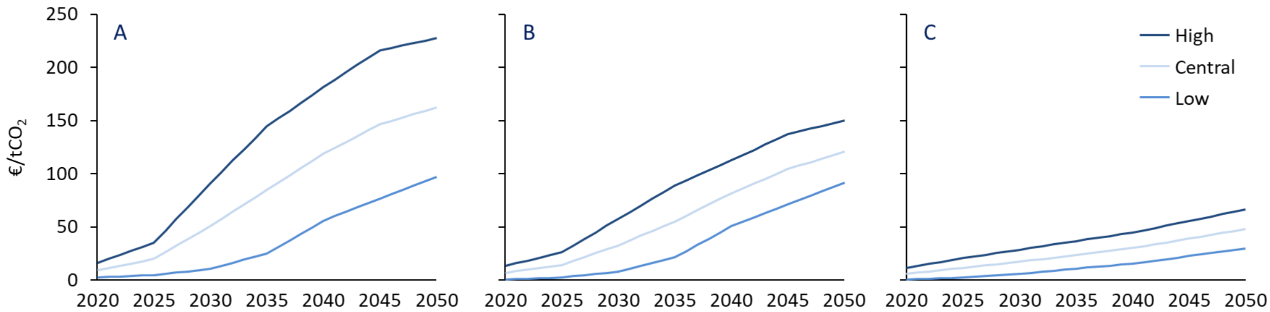

Figure 75: Carbon prices by region; A – Netherlands; B – UAE, Saudi Arabia & Kuwait, C – All other regions (€/tCO_2)

This analysis applies the carbon price to emissions around Gateway 2. This includes:

- Feedstock and fuel supply by region
- Electricity consumption
- CO_2 T&S
- Direct emissions from the production process

The impact of a carbon price on the LCOH is shown in the respective sensitivity analyses.

5.1.5 CO_2 Capture Rate

The capture rates for the processes analysed in this report are taken from literature and stakeholder engagement. This leads to a range of different capture rates for different technologies as shown in Table 15. Variations in the capture rate of these technologies are not considered in these case studies as the data collected from literature and stakeholders did not provide a breakdown of plant capital and operational costs, as well as energy requirements by process unit.

As previously described in this study, all production technologies have a capture rate more than 90%, supporting the low carbon hydrogen narrative. For the SNR and POX processes, increasing the capture rates above those stated in Table 15 will likely result in increased CAPEX and OPEX costs in the short term. However, in the 2050 scenario where carbon prices are greater and have a significant impact on the LCOH, higher capture rates will result in reduced carbon price costs. The technology with the highest capture rate is the HEE process as all emissions remain underground in the process. Other sources of emissions from these processes are also explored, as described in Section 5.1.6.

Table 15: Summary of CCS for oil-based hydrogen production technologies

H2 Production technology	SNR	POX	HEE
CCS Location	Post Reformer Flue Gas	Post Water Gas Shift	N/A
CO_2 capture technology	Mono-ethanol amine (MEA) based chemical absorption	Amine based- chemical absorption	N/A
CO_2 / Carbon Capture Rate	90%	96.50%	100%

5.1.6 Cost of CO_2 Abatement

Another important factor for policy makers, technology developers and industrial operators need to account for is the cost of CO_2 abatement. This is the total cost of reducing emissions when compared with an incumbent technology. In this study, the reference case is SMR without CCS in the Netherlands. The fraction of emissions that are associated with Gateway 1 and 2 of our analysis for SNR with CCS and the reference case in the Netherlands in 2020 are displayed in Figure 76. This highlights:

- The importance of the CO_2 capture rate. By capturing 90% of the CO_2 emissions from the SNR process, direct emissions are reduced from 17,750 to 2,544 ktonnes of CO_2 over the 25-year lifetime of the asset.
- Where the capture rate is greater than 90%, emissions from the delivery of feedstock and fuel to the industrial site becomes important. Greater electrification and the minimisation of fossil fuel consumption is expected to limit this impact.
- CO_2 T&S emissions in this scenario are only 1.3% of total emissions in Gateway 2.

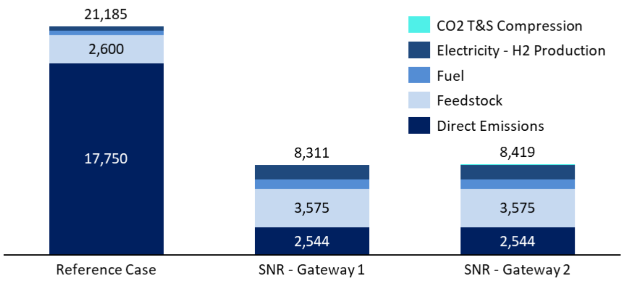

Figure 76: Emissions by source for the reference case and SNR (TRL 9) and the two gateways (ktonnes CO_2 over 25-year asset lifetime)

The cost of CO_2 abatement includes emissions up to Gateway 2 and is calculated as shown by the equation below:

$$Cost\ of\ CO_2\ Abatement = \frac{LCOH_{Scenario} - LCOH_{Reference}}{Emissions_{Reference} - Emissions_{Scenario}}$$

The cost of CO_2 abatement is discussed for each technology, both with and without a carbon price at the end of this section. The emissions included in this analysis are:

- Feedstock and fuel supply
- Electricity consumption
- CO_2 T&S
- Direct emissions from the production process

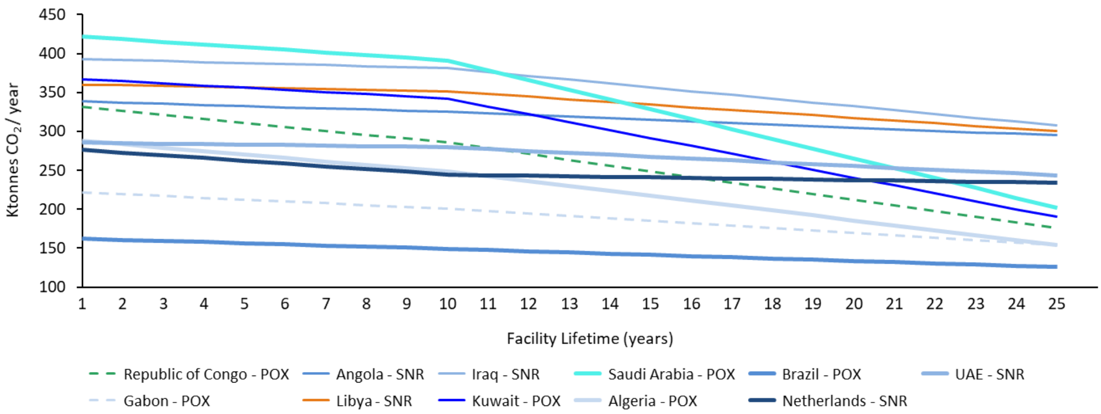

Figure 77: Emissions over the lifetime of the selected production technologies in the central case with the carbon intensity of the grid (ktonnes CO_2/year)

Assumptions for these inputs are given in the Appendices, Section 9.2. As the grid is decarbonised, POX which is more reliant on electricity is more quickly decarbonised than SNR which uses natural gas as a fuel. This is shown in Figure 77. Where the electricity supply is renewable, the annual emissions remain constant and POX technology is less polluting than SNR due to its high capture rate. HEE does not rely on grid electricity, as it is powered by an on-site hydrogen turbine and there are therefore no emissions associated with the process.

5.1.7 CO_2 Transport and Storage

As explored in Section 4, there are many different CO_2 T&S options. This analysis focusses on three of these:

- **Option 1 –** CO_2 is transported from one port to another via ship. It is then stored offshore via pipeline
- **Option 2 –** CO_2 is stored offshore via a pipeline network
- **Option 3 –** CO_2 is stored onshore via a pipeline network

A schematic of each of these processes is shown by Figure 78. Assumptions are given in the Appendices, Section 9.2.5.

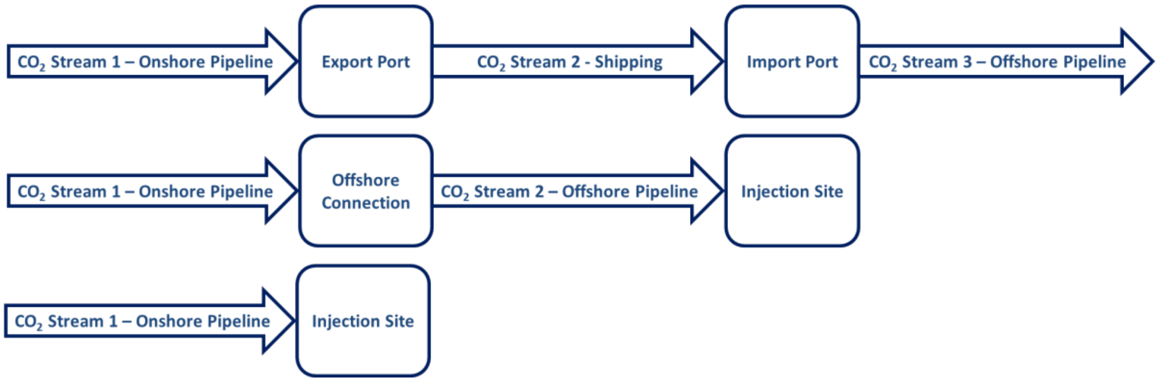

Figure 78: CO_2 Distribution Options

The cost for this T&S is applied as a fee to the H_2 production facility. This fee is calculated from Element Energy's "Shipping CO_2 – UK Cost Estimation Study"[169] and regionally available data.

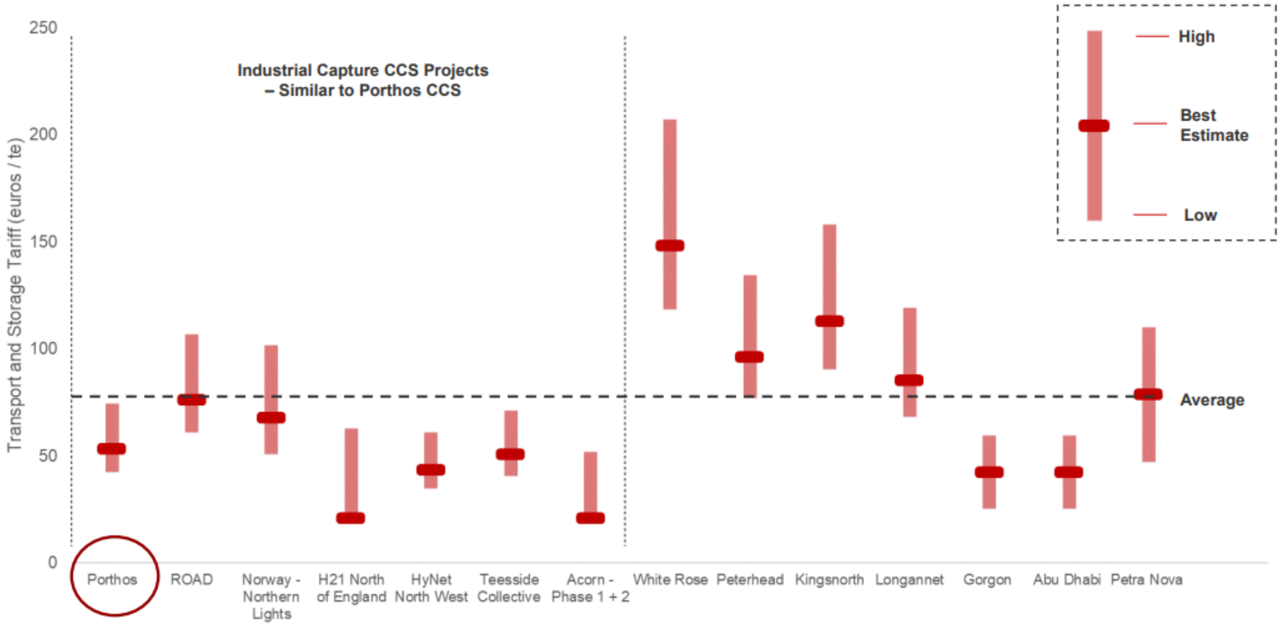

Figure 79: T&S tariffs for industrial CCS projects (€/tCO_2)[237]

Publicly available data for Porthos and the Abu Dhabi CCS projects as shown in Figure 79. These costs are higher than this study's internal calculations as they account for liabilities associated with leakage and the

[237] Xodus Advisory 2020, Porthos CCS – Transport and Storage (T&S) Tariff Review

provision for the expansion of carbon capture in the industrial clusters. To account for this, the Element Energy calculations for the 2020 analysis is scaled to match these low, central, and high-cost estimates.

The 2050 analysis recognises expected cost reductions using Element Energy's CO_2 Shipping model for CO_2 transportation. This analysis also only focusses on CO_2 transportation from the hydrogen production facilities. This low throughput over longer distances favours shipping over pipelines. However, as the scale of deployment increases, this dynamic will shift towards favouring pipelines instead.

5.1.8 Hydrogen Distribution

As explored in Section 4, there are several different hydrogen distribution and storage options. This analysis focuses on distribution by pipeline and by ship. A schematic of each of these processes is shown in Figure 80. The base case considers the closest export market, with other cases considering secondary markets. As for the CO_2 T&S, the hydrogen distribution and storage costs are applied as a flat fee. A variation of +/- 10% is applied in the sensitivity analysis.

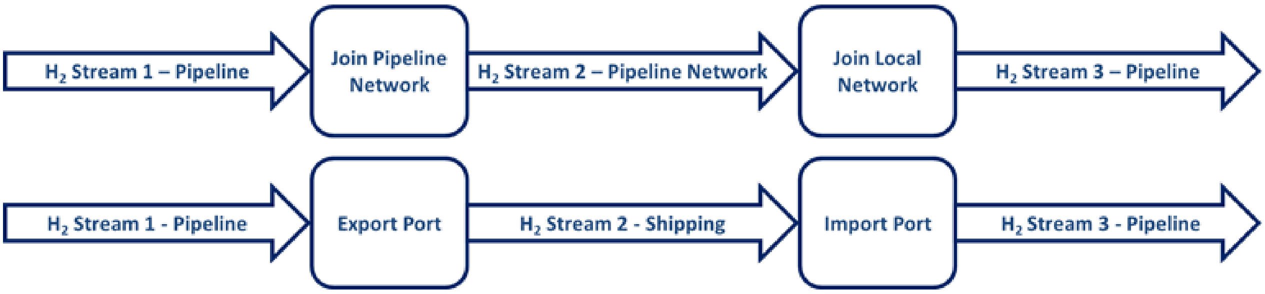

Figure 80: H_2 distribution options

Pipeline

The central case for all pipeline routes in this analysis is that new pipelines are required. Ongoing projects are exploring repurposing existing gas infrastructure to distribute hydrogen. The benefits of retrofitting are shown in Figure 81 with a 60.25% cost reduction in the annual cost of distribution from Algeria to Western Europe. Only a portion of the distribution network would be converted and so the actual cost will lie between these two values.

Shipping

Liquid hydrogen is not considered in this analysis as LOHCs and NH_3 are found to be lower cost. LOHCs are shown to be cheaper, as shown by Figure 81 and are used in the central case of this analysis. However, the difference between NH_3 and LOHC is 11.25% and it is expected both technologies are needed in a future hydrogen economy.

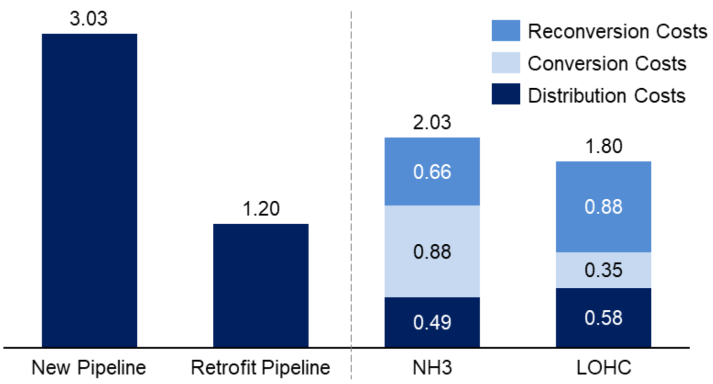

Figure 81: Annual hydrogen distribution costs for different pipeline options for Algeria to Western Europe (Left) and shipping options for UAE to Western Europe (Right) in 2020 (€/kgH₂)

5.1.9 Techno-economic Analysis of 2050 Deployment

This analysis also provides commentary on the supply of blue hydrogen from oil and oil-based products in 2050. By 2050, the hydrogen market is expected to have matured with uptake reaching similar levels across the globe. Resultantly, supply chains will have matured, technologies will have come down in cost and demand for hydrogen will be increasingly local. The following sensitivities are therefore considered:

Capital Costs

Capital cost reductions are expected with increased levels of deployment, particularly for those which are low TRL. The extent to which cost reductions are realised depends on the ramp up in the deployment of each technology and the associated learning rate. For example, the SNR CAPEX reduces by between 71% and 92% where it is assumed that:

- The cost reduction is equal to[238]:

$$Cost_{2050} = Cost_{2020} \times \left(\frac{Capacity_{2050}}{Capacity_{2020}}\right)^{-Learning\ Rate}$$

- Assuming that learnings for SMR and SNR are the same due to similar equipment.
- Assuming that SMR / SNR maintains its market share as the hydrogen market increases from 354Mtoe H_2 production to 1,959Mtoe H_2 production.
- Learning rates of between 5% and 20% are used[239].

For ease of comparison, it is assumed for each technology that their production capacity increases by a factor of 5.5, the same growth that is seen for the hydrogen sector, between 2020 and 2050.

Emissions

With the decarbonisation of the power grid, the average carbon intensity is expected to significantly reduce. In addition, large-scale energy users will have more opportunities to sign up to green energy tariffs. The carbon intensity of the grid is therefore reduced to a similar level of renewables in the Netherlands today (32.9 gCO_2/kWh[240]), reducing the carbon price.

Local Demand and H_2 Distribution

The increase in local demand means that reductions in the overall cost of H_2 distribution is possible. Furthermore, improvements in conversion and reconversion technologies for LOHCs and NH_3 will further bring down the cost of distribution by shipping.

CO_2 T&S Cost Reductions

As previously discussed, the costs associated with CO_2 T&S today are greater than Element Energy's in-house calculations since the modelled costs do not account for expansion, liabilities, risks and the respective margins on the processes. Through time, these costs are expected to reduce with improved understanding of CCS projects. The associated fee in 2050 is therefore only based on Element Energy's "Shipping CO_2 – UK Cost Estimation Study"[169]. These costs are presented in the Appendices, Section 9.2.5.

Feedstock, Fuel, Electricity and Carbon Pricing

Since forecasts from 2050 are sparse / not expected to be accurately representative, regional pricing is frozen at 2050 levels. This includes the cost of electricity, oil, naphtha and natural gas as well as the carbon price.

[238] European Commission 2012, Technology Learning Curves for Energy Policy Support
[239] US Department of Energy 2015, Using learning curves on energy-efficient technologies to estimate future energy savings and emission reduction potentials in the U.S. iron and steel industry
[240] WI

5.2 Techno-economic Assessment Results

The following section compares the LCOH at both a regional and technology-based level. For all regions, a range of oil based blue hydrogen technologies has been analysed. Technology choices for each country are not prescriptive and it is likely that many countries would be able to deploy all three oil-based production technologies analysed in this study. In this case, the LCOH for countries located in close geographical proximity are likely to act as an approximate proxy for alternative blue hydrogen production technologies (e.g., SNR in Saudi Arabia is likely to be similar cost to SNR in the UAE analysed in this study). Hydrogen is exported to the following three destinations with the base case considering exports to the closest market:

- **Western Europe** – Port of Rotterdam (Netherlands)
- **North America** – Cove Point LNG, Washington (USA)
- **Asia** - Port of Pyeongtaek-Dangjin (South Korea)

For all countries analysed, the LCOH is given for 2020 and 2050 in two scenarios:

- **Base Case** – assumes central cost estimates for CAPEX, OPEX, feedstock, electricity, CO_2 T&S and H_2 distribution.
- **Lowest Cost Pathway** – combines favourable sensitivities for each country (where possible) to identify the lowest cost option for blue hydrogen.

A full sensitivity analysis for each country is provided in the Appendix (Section 9.6.1).

As discussed previously, whilst shown to be a promising technology, HEE has a comparatively lower TRL and therefore should not be directly compared with SNR or POX. HEE should be treated as a promising technology which needs to be proven in demonstration projects.

5.2.1 Regional Analysis

Middle East

2020

The LCOH in the Middle East base case and lowest cost pathway in 2020 are provided in Figure 82. In the base case, the LCOH ranges from 66-119% greater than the SMR incumbent, primarily due to the significant hydrogen distribution costs that result from shipping to markets in Asia. POX in Kuwait is the lowest cost option in this scenario, whilst SNR in Iraq is the most expensive country analysed in this region.

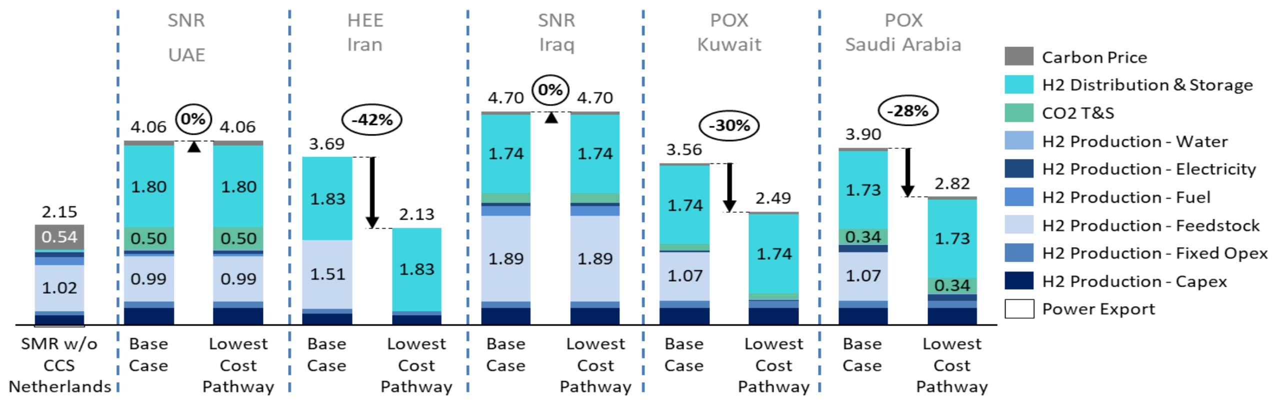

Figure 82: LCOH comparison for base case and lowest cost pathway scenarios in the Middle East in 2020 (SNR and POX TRL 9, HEE TRL 4) - € / kgH_2

In the lowest cost pathway scenario, HEE in Iran is lower cost than the SMR incumbent by 0.02 €/kgH_2. This is primarily due to the assumption that oil from a depleted well is zero cost and existing infrastructure can be utilised. The LCOH for POX in Kuwait and Saudi Arabia is reduced by 30% and 28% respectively, where the oil feedstock is assumed to be a waste product and zero cost. Although this is a significant cost reduction, POX remains 16-31% higher cost than the SMR incumbent. The feedstock costs for Naphtha remain high in the UAE and Iraq, resulting in the LCOH remaining unchanged from the base case in 2020.

2050

The LCOH in the Middle East base case and lowest cost pathway in 2050 are provided in

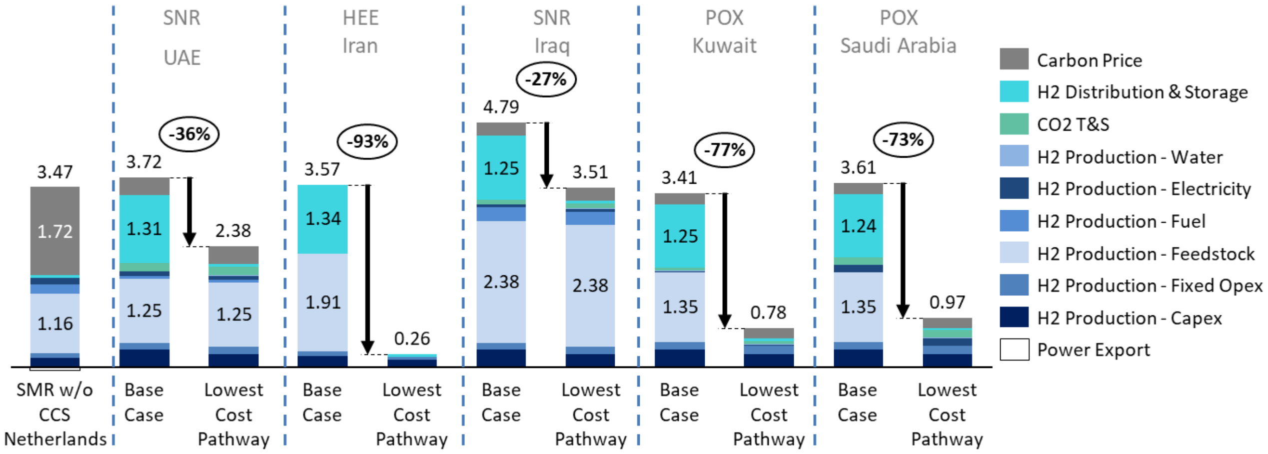

Figure 83. In the base case, the LCOH ranges from 2% cheaper to 38% greater than the SMR incumbent. POX in Kuwait remains the lowest cost option in the base case scenario, whilst SNR in Iraq is the highest cost option. The hydrogen distribution cost component remains high for all countries.

In the lowest cost pathway scenario in 2050, all hydrogen is assumed to be consumed domestically and thus distributed to local users via pipeline. When combined with other favourable sensitivities, this results in a very low-cost pathway for hydrogen production for HEE and POX technologies in the Middle East. HEE in Iran has a LCOH of only 0.26 €/kgH_2, whereas POX in Kuwait and Saudi Arabia are 0.78 €/kgH_2 and 0.97 €/kgH_2, respectively. SNR in the UAE is lower cost than the incumbent which is significantly impacted by the carbon price in 2050, whereas SNR in Iraq remains expensive due to the higher cost of Naphtha feedstock.

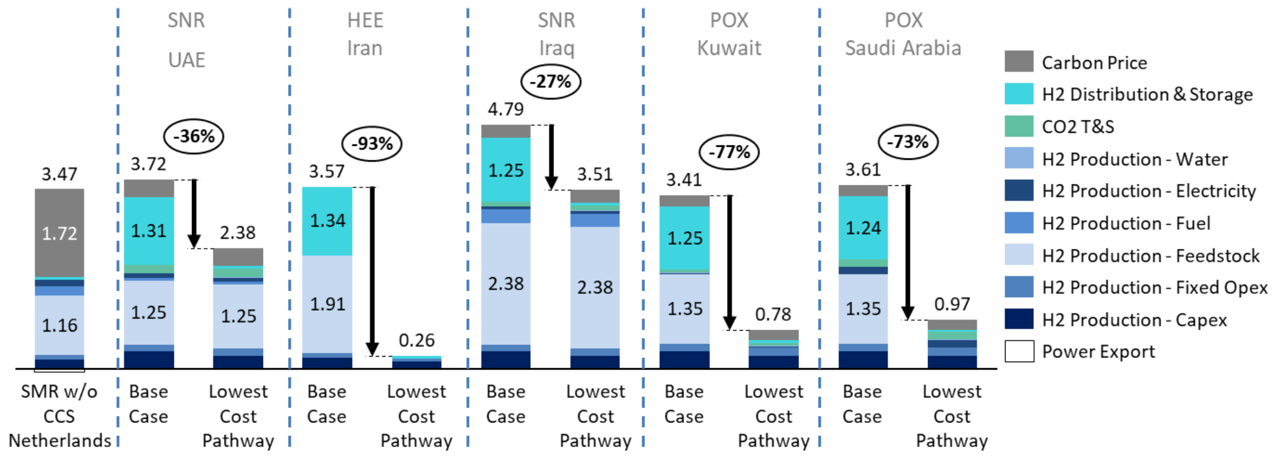

Figure 83: LCOH comparison for base case and lowest cost pathway scenarios in the Middle East in 2050 (SNR and POX TRL 9, HEE TRL 4) - € / kgH_2

West Africa

2020

The LCOH in the West Africa base case and lowest cost pathway in 2020 are provided in Figure 84. In the base case, the LCOH ranges from 64-182% greater than the SMR incumbent, this is due to the significant hydrogen distribution costs that result from shipping to markets in Europe. HEE in Equatorial Guinea is the lowest cost option in this scenario, whilst SNR in Angola is the most expensive country analysed in this region, due to a result of high naphtha feedstock costs and long-distance pipeline requirements for offshore CO_2 T&S.

In the lowest cost pathway scenario, HEE in Equatorial Guinea is lower cost than the SMR incumbent by 8%. This is primarily due to the assumption that oil from a depleted well is zero cost and existing infrastructure can be utilised. HEE in Nigeria is also found to be cost competitive at only 0.02 €/kgH_2 greater than the SMR incumbent. The LCOH for POX in the Republic of Congo and Gabon is reduced by 26% and 24% respectively, where the oil feedstock is assumed to be a waste product and zero cost. Although this is a significant cost reduction, POX remains 46-59% higher cost than the SMR incumbent. The feedstock costs for Naphtha remain high in Angola, resulting in the LCOH remaining unchanged from the base case in 2020.

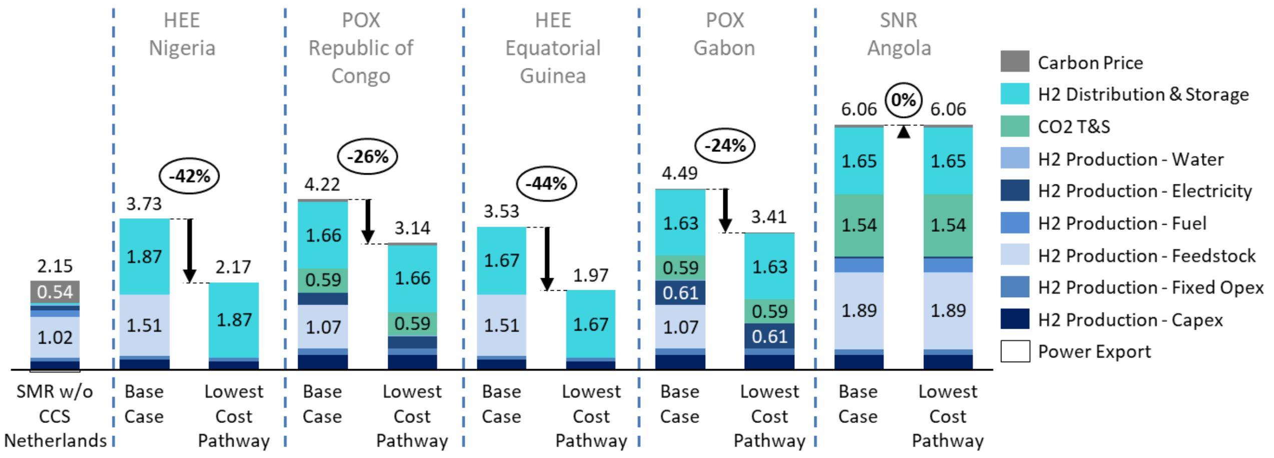

Figure 84: LCOH comparison for base case and lowest cost pathway scenarios in West Africa in 2020 (SNR and POX TRL 9, HEE TRL 4) – € / kgH₂

2050

The LCOH in the West Africa base case and lowest cost pathway in 2050 are provided in Figure 85. In the base case, the LCOH ranges from 2% cheaper to 46% greater than the SMR incumbent. HEE in Equatorial Guinea remains the lowest cost option in the base case scenario, whilst SNR in Angola is the highest cost option. The hydrogen distribution cost component remains high for all countries.

In the lowest cost pathway scenario in 2050 it is assumed that all hydrogen is consumed domestically and therefore distributed to local users via pipeline. When combined with other favourable sensitivities, this results in a very low-cost pathway for hydrogen production for HEE and POX technologies in West Africa. HEE in Nigeria and Equatorial Guinea have a LCOH of only 0.26 €/kgH_2 and 0.25 €/kgH_2 respectively, whereas POX in the Republic of Congo and Gabon are 1.03 €/kgH_2 and 1.33 €/kgH_2 respectively. SNR in Angola remains expensive due to the higher cost of Naphtha feedstock.

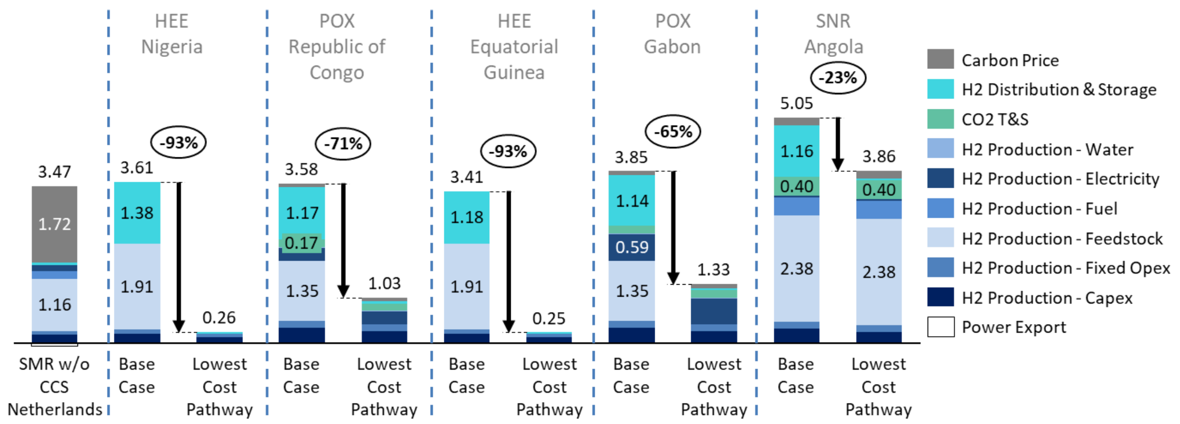

Figure 85: LCOH comparison for base case and lowest cost pathway scenarios in West Africa in 2050 (SNR and POX TRL 9, HEE TRL 4) – € / kgH₂

North Africa, Latin America and the North Sea

2020

The LCOH in the North Africa, Latin America and North Sea for base case and lowest cost pathways in 2020 are provided in Figure 86. In the base case, the LCOH ranges from 60-172% greater than the SMR incumbent.

High CO_2 T&S costs components are observed for scenarios in Algeria and Brazil where large onshore and offshore pipeline distances are required respectively. In all cases other than the Netherlands, hydrogen distribution costs are high due to the large distances involved in shipping hydrogen to European and North American markets. SNR in the Netherlands is expensive due to the high cost of naphtha in the region. HEE in Venezuela is the lowest cost option in this scenario.

In the lowest cost pathway scenario, HEE in Venezuela is the only country to have a lower LCOH than the SMR incumbent, with a LCOH reduction of 13%. This is primarily due to the assumption that oil from a depleted well is zero cost and existing infrastructure can be utilised. The LCOH for POX in Algeria and Brazil is reduced by 29% and 19% respectively, where the oil feedstock is assumed to be a waste product and zero cost. However, all SNR and POX technologies remain significantly higher cost than the SMR incumbent for the regions analysed.

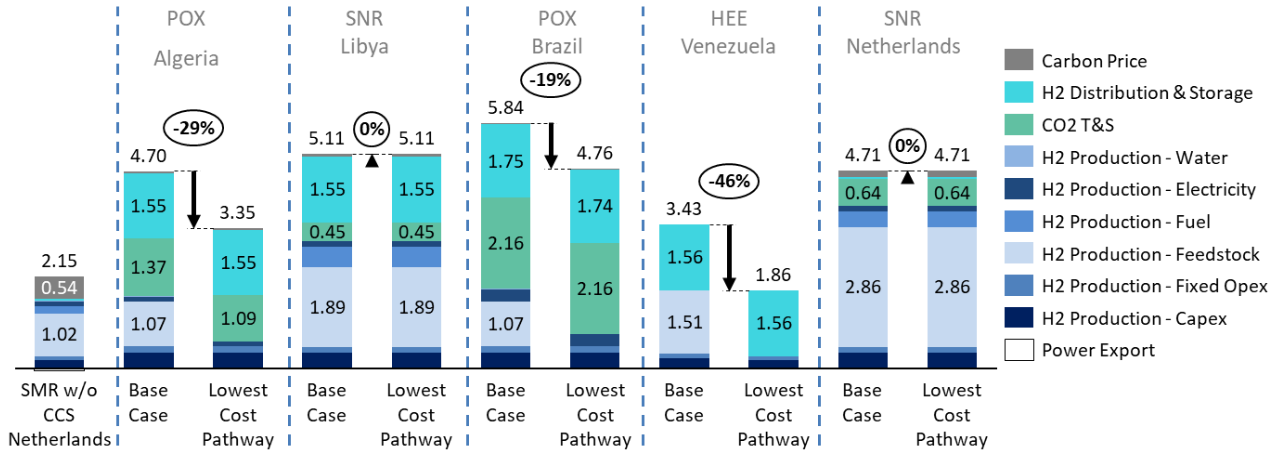

Figure 86: LCOH comparison for base case scenarios in North Africa, Latin America and the North Sea in 2020 (SNR and POX TRL 9, HEE TRL 4) – € / kgH_2

2050

The LCOH in the North Africa, Latin America and North Sea for base case and lowest cost pathways in 2050 are provided in Figure 87. In the base case, the LCOH ranges from 5% cheaper to 54% greater than the SMR incumbent. The hydrogen distribution component remains high for shipping over long distances to European and North American markets in all cases other than SNR in the Netherlands. HEE in Venezuela remains the lowest cost option in the base case scenario, whilst SNR in the Netherlands is the highest cost option even though hydrogen is distributed locally due to the high cost of naphtha feedstock in the Netherlands.

In the lowest cost pathway scenario in 2050, all hydrogen is assumed to be consumed domestically and therefore distributed to local users via pipeline. When combined with other favourable sensitivities, this results in a very low-cost pathway for hydrogen production for HEE in Venezuela at a LCOH of 0.26 €/kgH_2. POX in Algeria and Brazil can be produced at LCOH of 1.12 €/kgH_2 and 1.43 €/kgH_2, respectively when oil feedstock is assumed to be a waste product.

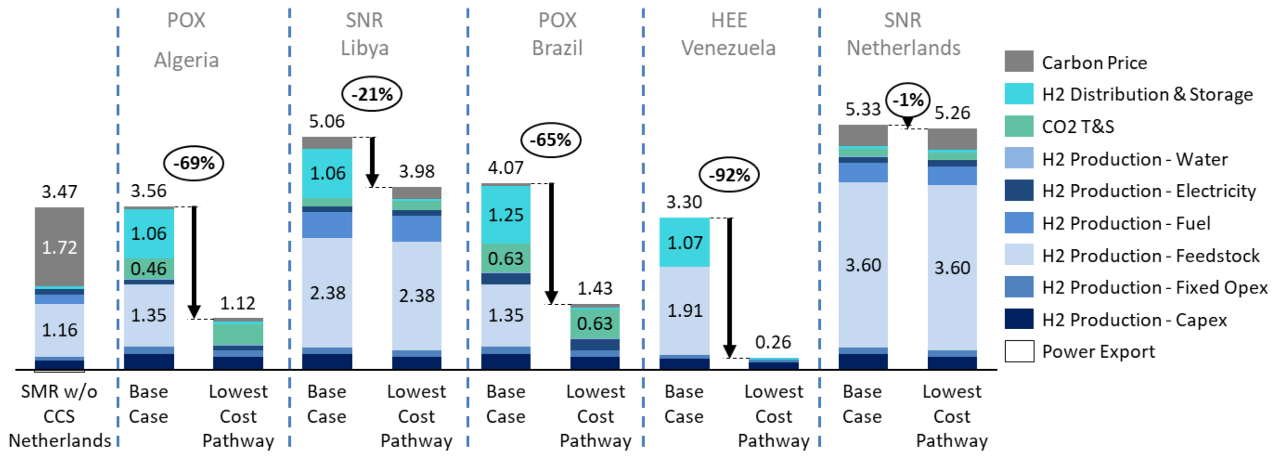

Figure 87: LCOH comparison for base case and lowest cost pathways scenarios in North Africa, Latin America and the North Sea in 2050 (SNR and POX TRL 9, HEE TRL 4) – € / kgH_2

5.2.2 Technology Based Analysis

SNR

2020

The LCOH in the SNR base case in 2020 is provided in Figure 88. For SNR technology, the base case is also the lowest cost pathway. In the case of Angola, Libya and Iraq, the cost of feedstock is the same resulting in similar Gateway 1 (hydrogen production) costs. The UAE has the potential to access naphtha feedstock cheaper than natural gas in the Netherlands, resulting in Gateway 1 costs only 0.10 €/kgH_2 greater than the SMR incumbent. Hydrogen shipping is a hight cost component for all regions other than the Netherlands due to the large distances involved.

The greatest cost variations come from the CO_2 T&S component. For all regions, CO_2 pipelines will require developing with onshore pipelines considered in the UAE, Libya and Iraq, and offshore pipelines considered in the Netherlands and Angola. Short distance onshore CO_2 pipelines in Iraq result in the lowest CO_2 T&S costs. Whereas Angola has the highest cost due to the large offshore pipeline distances that could be required to connect to potential offshore storage sites.

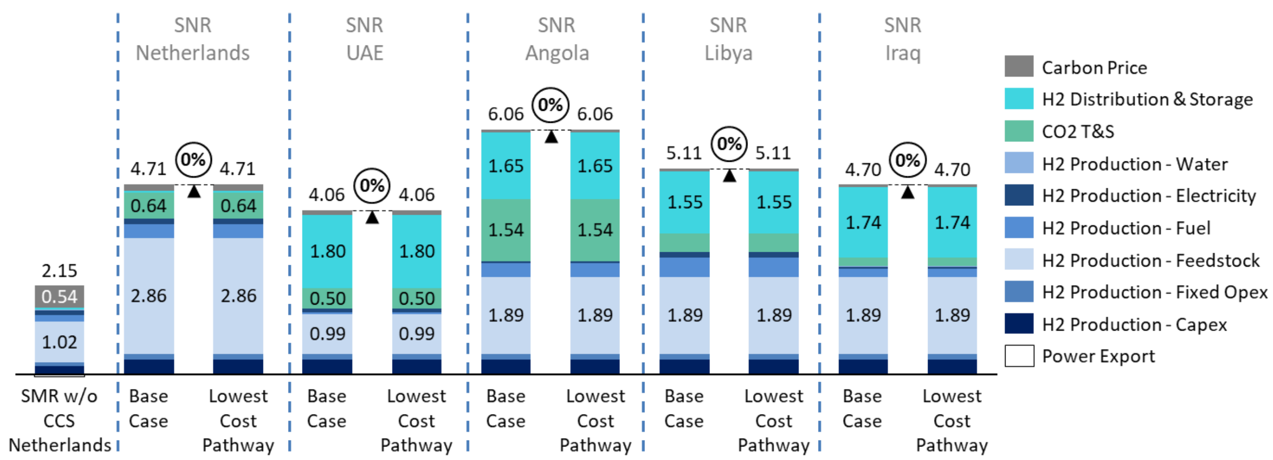

Figure 88: LCOH comparison for SNR base case and lowest cost pathway scenarios in 2020 (All TRL 9) - € / kgH_2

2050

The LCOH in the SNR base case and lowest cost pathways in 2050 are provided in Figure 89. In both the base case and the lowest cost pathway, the UAE has access to the lowest cost Naphtha feedstock, whilst the

Netherlands is the most expensive. In all cases, the cost of CO_2 T&S is significantly reduced in 2050 with a 74% reduction in the case of Angola. The cost of hydrogen distribution remains high for all cases where shipping is considered, whilst distribution to local users results in a significant cost saving in the lowest cost pathway. For all regions, cost reductions at Gateway 1 are the most crucial for ensuring future competitiveness and therefore the utilisation of low-cost feedstock and fuel should be prioritised.

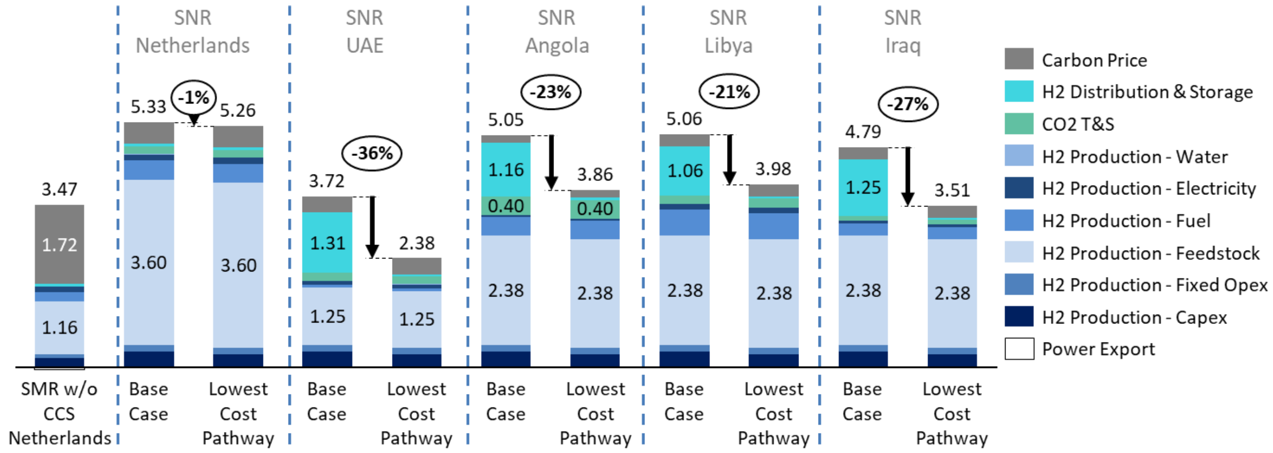

Figure 89: LCOH comparison for SNR base case and lowest cost pathway scenarios in 2050 (All TRL 9) - € / kgH_2

POX

2020

The LCOH in the POX base case and lowest cost pathways in 2050 are provided in Figure 90. For all cases considered, the cost of oil feedstock is the same with variations in the Gateway 1 costs coming from variations in the local electricity costs. In Kuwait, it is possible to access very low-cost industrial electricity, whereas higher electricity prices in Gabon, make this cost component more significant. For all cases considered, hydrogen distribution costs remain high due to shipping over large distances to European, North American, and Asian markets. However, this component only varies by a maximum of 0.20 €/kgH_2 for all regions considered. For all regions, the greatest variation comes from the CO_2 T&S costs. Kuwait has potential to develop relatively short distance onshore pipelines resulting in low costs, whereas Brazil is likely to require long distance offshore pipelines to access local geological storage that are significantly more expensive to develop.

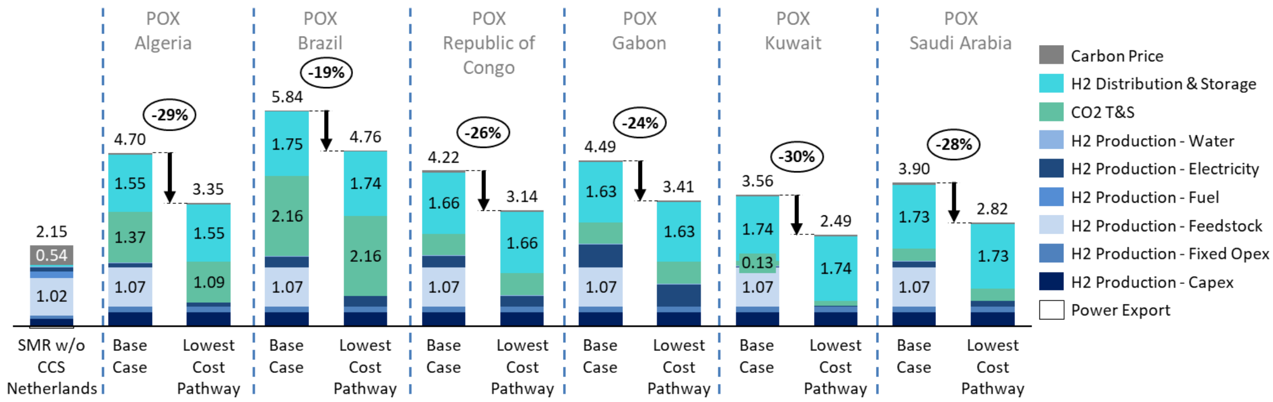

Figure 90: LCOH comparison for POX base case scenarios in 2020 (All TRL 9) - € / kgH_2

2050

The LCOH in the POX base case and lowest cost pathways in 2050 are provided in Figure 91. In a similar manner to 2020, the cost of oil feedstock is the same for all regions and variations in the Gateway 1 cost come from the local price of electricity. Where large distance CO_2 pipelines are required in Algeria and Brazil, the CO_2 T&S component is reduced by 66% and 71% in the base case respectively. This is due to increased hydrogen production resulting in increased CO_2 pipeline utilisation and technical learnings reducing costs due to increased levels of deployment. Very low-cost POX hydrogen production can therefore be achieved in regions with access to waste oil feedstock, low-cost CO_2 T&S and cheap local electricity.

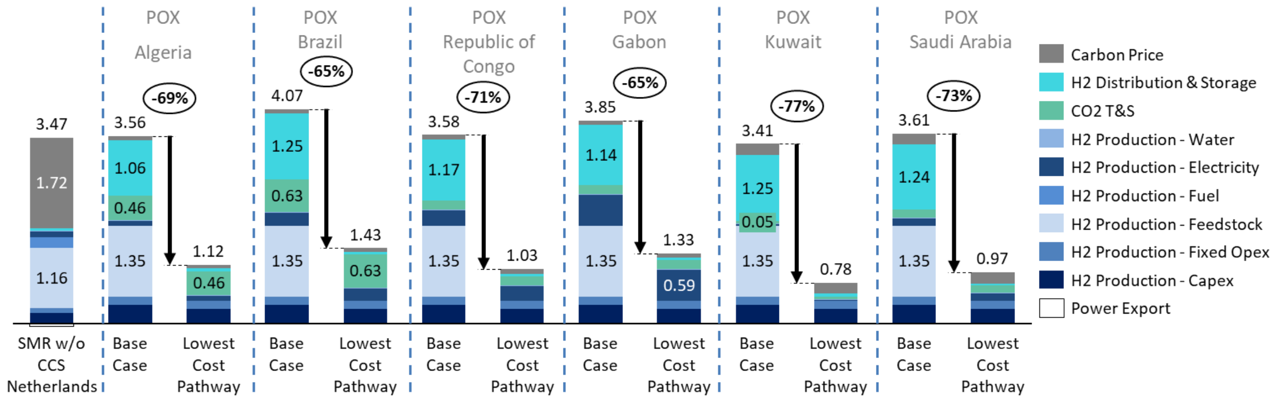

Figure 91: LCOH comparison for POX base case and lowest cost pathway scenarios in 2050 (All TRL 9) - € / kgH_2

HEE

2020

The LCOH in the HEE base case and lowest cost pathways in 2020 are provided in Figure 92. For all cases considered, the cost of oil feedstock is the same resulting in identical Gateway 1 costs. Variations in the LCOH come from differences in shipping distances; however, the H_2 distribution component only varies by 0.31 €/kgH_2 across all regions. The lowest cost pathway shows that HEE can be cost competitive with the incumbent SMR technology in all regions when oil from depleted wells can be accessed at zero cost.

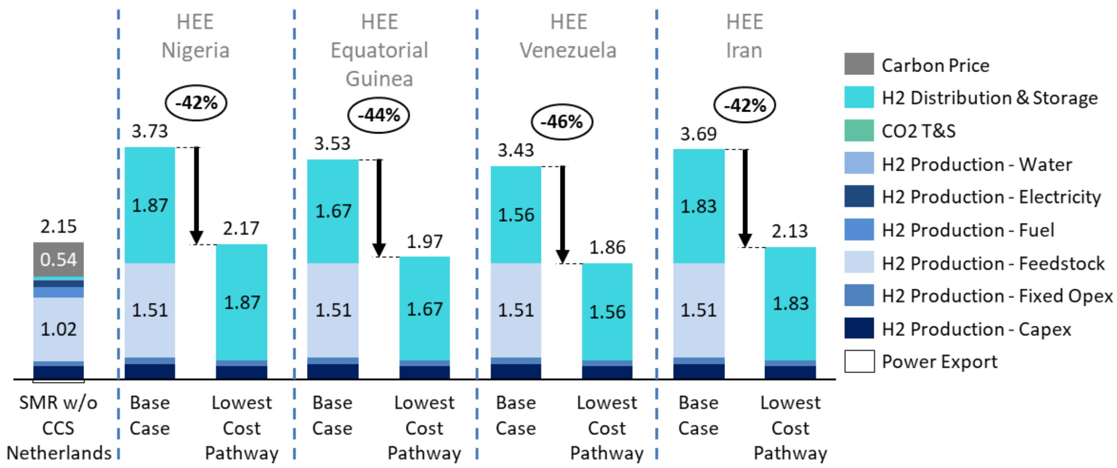

Figure 92: LCOH comparison for HEE base case and lowest cost pathway scenarios in 2020 (All TRL 4) - € / kgH_2

2050

The LCOH in the HEE base case and lowest cost pathways in 2050 are provided in Figure 93. In a similar manner to 2020, the cost of oil feedstock is the same for all regions and variations in the LCOH come from variations in the H_2 distributions costs. In the lowest cost pathway where it is assumed that hydrogen is distributed to local markets via pipeline and oil from depleted wells can be accessed at zero cost, HEE has the potential to supply hydrogen at very low prices. Cost reductions of up to 93% in comparison to the SMR case in the Netherlands could be achieved resulting in the lowest overall cost of all the technologies analysed in this study. However, it should be noted that HEE is currently at TRL 4-6 and is yet to be deployed at scale, significantly reducing the uncertainty surrounding this technology.

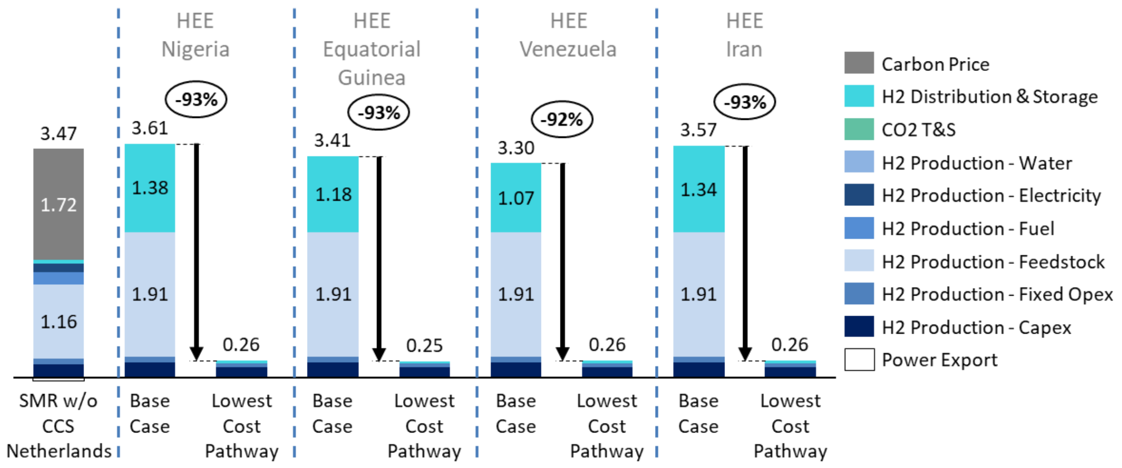

Figure 93: LCOH comparison for HEE base case and lowest cost pathway scenarios in 2050 (All TRL 4) - € / kgH$_2$

6 Life Cycle Assessment

This section presents the methodology and environmental footprint results from CE Delft's LCA of the oil and oil-based hydrogen production scenarios (including the benchmark – SMR without CCS), as defined in Section 5.

The LCA methodology is described in Section 6.1, the life cycle inventory data is discussed in Section 6.2 and the results of the impact assessment are discussed in Section 6.3. In Section 6.4, the LCA results in this study are compared with the parallel study done on natural gas-based and alkaline electrolysis production routes. In Section 6.5, the uncertainties and limitations of this LCA are discussed. Conclusions based on these results are presented in Section 8.

6.1 LCA Methodology

The LCA methodology is used to determine the impact of a product or service on the environment throughout the entire life cycle. It is used to compare the environmental impact of different products or services that fulfil the same function.

This report contains a screening LCA[241] of the 15 different oil and oil-based hydrogen production scenarios described in Section 4.4 (Table 5, Table 6 and Table 7), as well as of the benchmark. Natural gas based SMR without CCS in the Netherlands is chosen as the benchmark grey hydrogen technology, as this is currently the most common production process for hydrogen.

This study is carried out in line with the ISO 14040/44 norms which provide the principles, guidelines, and framework for LCA's. SimaPro (v9.1.1.1) software was used to model the scenarios and carry out the LCAs. This section describes the methodological choices of the LCA.

6.1.1 Goal and Scope Definition

Goal

The goal of this LCA study is to provide insight into the carbon footprints of 15 different oil-based blue hydrogen production scenarios (listed in Section 4.4) and compare these to a benchmark scenario (natural gas based hydrogen production using SMR without CCS in the Netherlands).

Scope

Functional Unit

When comparing different scenarios, the basis of that comparison needs to be the same for each scenario. Therefore, a functional unit is defined which serves as the basis upon which the analysis of each of the hydrogen production scenarios is carried out.

The functional unit used in this study is: the production of 1 kg of hydrogen (H_2) compressed to 200 bar with a minimum purity of 97%. The hydrogen pressure specification of 200 bar is defined by Valente et al[242]. The rationale behind the hydrogen purity specification is described in Section 2.1.

System Boundaries

The system boundaries describe which process steps as well as associated inputs and outputs related to the functional unit are included in the LCA.

In this study, cradle-to-gate system boundaries are used, in line with the LCA methodology for hydrogen production proposed by Valente et al, as shown in Figure 94. The cradle-to-gate system boundaries includes all process steps from the extraction of the raw materials up to and including the production of compressed hydrogen[243]. This means that all processes that are required to produce (200 bar, >97% purity) hydrogen and

[241] See Section 6.1.1 for more information on why these technologies are considered 'screening' LCA's.
[242] Valente et al 2017, Harmonised life-cycle global warming impact of renewable hydrogen
[243] It is assumed that the H_2 is compressed at the H_2 production facility.

to transport and store (part of) the captured CO_2 using CCS are considered (e.g., production of required fuel, feedstock, and electricity).

The capital goods of the foreground system (i.e., equipment/infrastructure required in the hydrogen production facility) are not included in the scope of this LCA as these usually have a negligible share in the total carbon footprint of hydrogen production[244].

Capital goods are included in the background processes in the LCA database (Ecoinvent v3.6). These capital goods include, for example, the construction of pipelines and ships for transport and storage of CO_2, and the production of power plants and windmills for electricity production.

A cradle-to-gate system boundary stops at the 'gate' of the production facility. Therefore, transportation of hydrogen from the producer to the consumer, any additional hydrogen purification steps required for specific applications, consumption of the hydrogen and end-of-life treatment of hydrogen are not accounted for in this analysis.

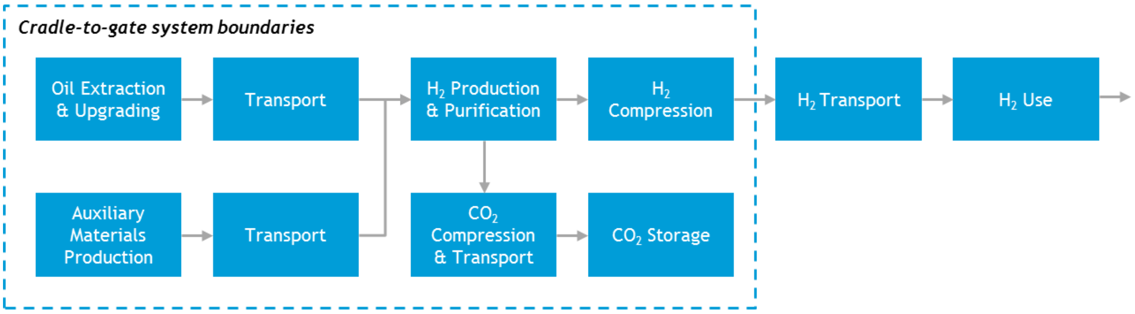

Figure 94: Cradle-to-gate system boundaries of hydrogen production from oil

Technological, Geographical and Temporal Scope

The technological, geographical, and temporal scope of the LCA performed in this study are as follows:

- **Technological scope:** The technological specifications and assumptions for each of the analysed scenarios, including CCS, are given in Section 9.2. Not all technologies have the same TRL (as described in Section 5.1.1). In Section 8.3, the uncertainties involved with data collection of technologies with a low TRL are discussed in more detail. For electricity production, the average mix of the grid is used.
- **Temporal scope:** The hydrogen production scenarios are modelled for the current situation (2020). Additionally, a sensitivity analysis evaluates the effects of deploying the technologies in 2030 by modelling the expected electricity mix (and related carbon footprint) for 2030 for each country (see Section 6.3.3). For CCS, it is assumed the captured CO_2 is stored underground for more than 100 years. According to the ILCD guidelines[245], the EU standard for LCAs, if CO_2 is stored underground for more than 100 years, the stored CO_2 leads to a CO_2 emission reduction[246]. As it is assumed that this is the case for CCS, CO_2 emission reduction can be applied.
- **Geographical scope:** As mentioned in the introduction of Section 6.1, different countries are considered in the scenarios studied. The data used for the assessments is – where available – country/region specific (e.g., for the carbon footprint of the electricity production, the country specific electricity mix is used).

[244] Antonini et al 2020, Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis
[245] IPCC also generally uses a 100-year time horizon when calculating carbon footprints.
[246] ILCD 2010, ILCD Handbook - General guide on LCA - Detailed guidance (europa.eu)

6.1.2 Environmental Impact Categories

LCAs can be used to calculate a range of different environmental impacts. This study focusses on the global warming potential (i.e., carbon footprint) of the selected production scenarios. The carbon footprint is expressed in kg CO_2 equivalents (eq.)/kg H_2.

Additionally, to show possible environmental trade-offs between carbon footprint and other impact categories, the LCA results for other environmental impact categories are provided in the Appendices, Section 9.5. The following impact categories are included there:

- Acidification
- Human toxicity (cancer effects)
- Human toxicity (non-cancer effects)
- Ozone depletion
- Particulate matter
- Ionising radiation human health
- Ionising radiation ecosystems
- Photochemical ozone formation
- Terrestrial eutrophication
- Freshwater eutrophication
- Marine eutrophication
- Freshwater ecotoxicity
- Land use
- Mineral, fossil and renewable resource depletion
- Water resource depletion
- Cumulative non-renewable energy demand.

The following life cycle impact assessment methods are used to calculate the results[247]:

- Carbon footprint: IPCC 2013 GWP 100a V1.03;
- Cumulative energy demand: Cumulative Energy Demand V1.11;
- Other environmental impact categories: ILCD 2011 Midpoint+ V1.11 / EC-JRC Global, equal weighting.

6.1.3 Multifunctionality and Allocation

Next to production of the main desired product, some processes also produce other products called co-products. When conducting an LCA for such multifunctional processes (e.g., when H_2 is a co-product in the chlor-alkali process), the carbon footprint of the production process must be distributed between the different products. The ISO LCA standards specify different ways of ‘solving multifunctionality’, including subdivision, system expansion and allocation.

In this study, however, no co-products are produced and so there is no need to model any system expansion or allocation[248].

6.1.4 Data Collection, Quality and Uncertainties

The data collection and selection for the LCA, involving extensive literature review and stakeholder interviews, is described in Section 2.2. The quality and uncertainty associated with the selected data is described in Section 2.2 and the Appendices, Section 9.4.

[247] In these impact assessment methods, hydrogen emissions do not contribute to global warming. Recent research suggests hydrogen does contribute to global warming, however this has not (yet) been adopted in common LCA methods.
[248] Some of the technologies analysed in this study produce steam and/or electricity. However, as these are used within the system itself, these are not considered co-products.

The data quality of the benchmark (SMR without CCS) is very high because of high TRL and excellent data availability. As described in Section 2.2.2, HEE has low TRL and the data availability for SNR and POX is comparatively poor. Consequently, the LCAs are relatively uncertain and difficult to verify, and are thus considered screening LCAs. The term ‘screening LCA’ is used because of the relative uncertainty (see Section 9.2). The methodology and analysis remain the same for all of the LCAs.

The collected data provided in Section 9.2 is combined with the environmental (background) data from the Ecoinvent v3.6 LCA database unless more recent/accurate data is available. The Ecoinvent/alternative LCA background data used for modelling is listed in the Appendices, Section 9.4.

6.1.5 Sensitivity Analyses

The results of an LCA depend on choices and assumptions made regarding the methodology and (process and background) data. To investigate the sensitivity of the results to these choices and assumptions, sensitivity analyses are conducted.

In this study, the following sensitivity analyses have been carried out in order to assess the effects of changing key parameters on the overall carbon footprint of the different technologies:

- Sensitivity Analysis 1: For all scenario’s (including the benchmark), the electricity mix has been adjusted to the country specific expected mix in 2030.
- Sensitivity Analysis 2: The carbon capture rate of SNR in the Netherlands is increased from 90% to 99%.
- Sensitivity Analysis 3: Local vs. non-local CO_2 T&S options are analysed for Angola, Algeria, and Kuwait.

Further explanation on the sensitivity analyses can be found in Section 6.3.3.

Additionally, the effect of other important assumptions made in this study are addressed qualitatively in Section 6.5 ‘Uncertainties’.

6.2 Life Cycle Inventory

The life cycle inventory describes how the different hydrogen production scenarios are modelled in the LCA, for instance in terms of the process data implemented and background datasets used.

The inventory data and assumptions of the hydrogen production scenarios used to model the LCAs can be found in the Appendices, Section 9.2 and 9.4. The inventory data and assumptions for CO_2 T&S and compression of hydrogen can be found in the Appendices, Section 9.2. Additionally, the carbon footprint of feedstock and electricity production and conversion factors used for modelling can be found in the Appendices, Section 9.2.8.

6.3 LCA Results

In this section the results of the life cycle assessments and sensitivity analyses are presented. Section 6.3.1 explains how the results of the LCAs are presented using a waterfall chart. Section 6.3.2 shows and analyses the carbon footprint results of the life cycle assessments of all oil-based hydrogen technologies and the benchmark. Finally, Section 6.3.3 investigates the sensitivities of the results of the LCAs in several sensitivity analyses.

This section focuses on the carbon footprint of the different technologies. Section 9.5 in the Appendices presents the effects of the hydrogen technologies on a selection of other environmental impact categories.

6.3.1 Example: Presentation of the LCA Results

This section explains how the results of the LCAs of the different blue hydrogen technologies are presented. One stacked bar graph is given to show the carbon footprint for each blue hydrogen production technology.

The bar is split up into different segments which represent the carbon footprint of different system inputs and outputs. These contribute to the total carbon footprint. This is called a contribution analysis.

By presenting the results in this way, a better understanding is gained on which parts of the hydrogen production scenario contribute the most to the carbon footprint. Additionally, these results help in deciding where the focus should be when aiming to reduce the carbon footprint.

Figure 95 is an explanatory waterfall chart in which the bar chart carbon footprint of one scenario (SNR in the Netherlands) is broken down. In this example, the categories contributing to the total carbon footprint are:

- Naphtha (feedstock) (including the carbon footprint of the production of the feedstock and its transport to the hydrogen plant).
- Natural gas (fuel) (including carbon footprint of the production and transport of natural gas, as well as the carbon footprint of using it as a fuel).
- Electricity from the grid.
- Other (included tap water and wastewater treatment).
- CO_2 T&S.
- Generated CO_2
- Stored CO_2.

The first six of these categories add up to a carbon footprint of 15.08 kg CO_2 eq./kg H_2. However, as a significant fraction of the generated CO_2 is stored, the category 'Stored CO_2' is subtracted from this footprint. This adds up to a total carbon footprint of 3.44 kg CO_2 eq./kg H_2.

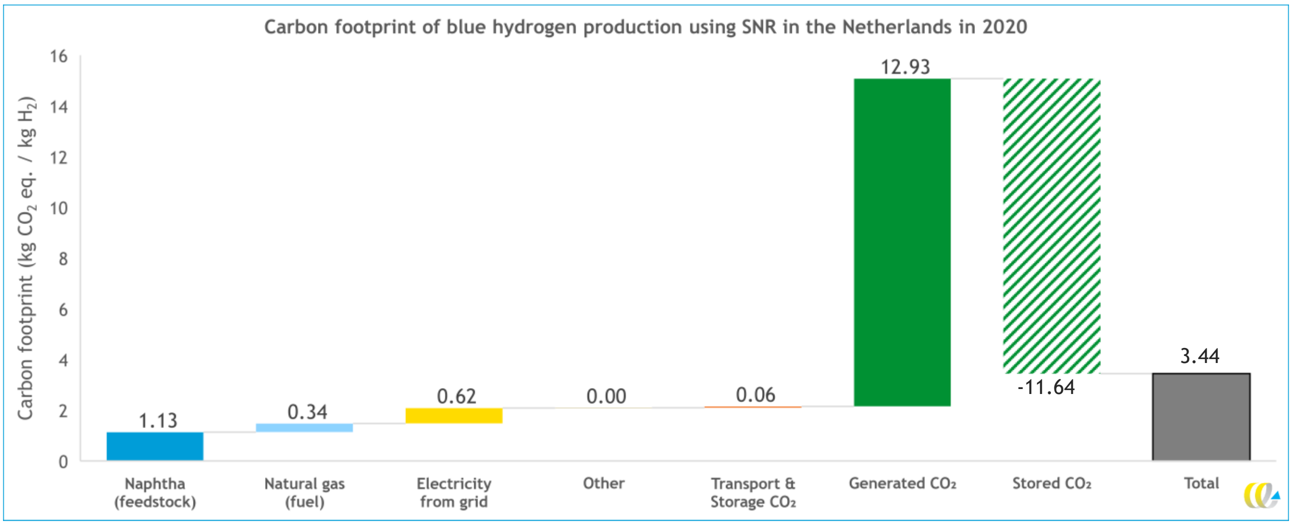

Figure 95: Explanatory waterfall chart on the presentation of the LCA results. The colours of the bars coincide with the colours used in stacked bar graphs below (e.g. Figure 96).

6.3.2 Carbon Footprint of Oil-Based Blue Hydrogen Technologies (2020)

In Figure 96 the contribution analyses of the carbon footprints of each of the studied oil and oil-based blue hydrogen production scenarios are presented[249]. The results are provided in tabular form in the Appendices, Section 9.6.3. A more detailed description of the results per hydrogen production technology is given below the figure.

[249] See Section 6.3.1 for an explanation about this method of presenting the LCA results

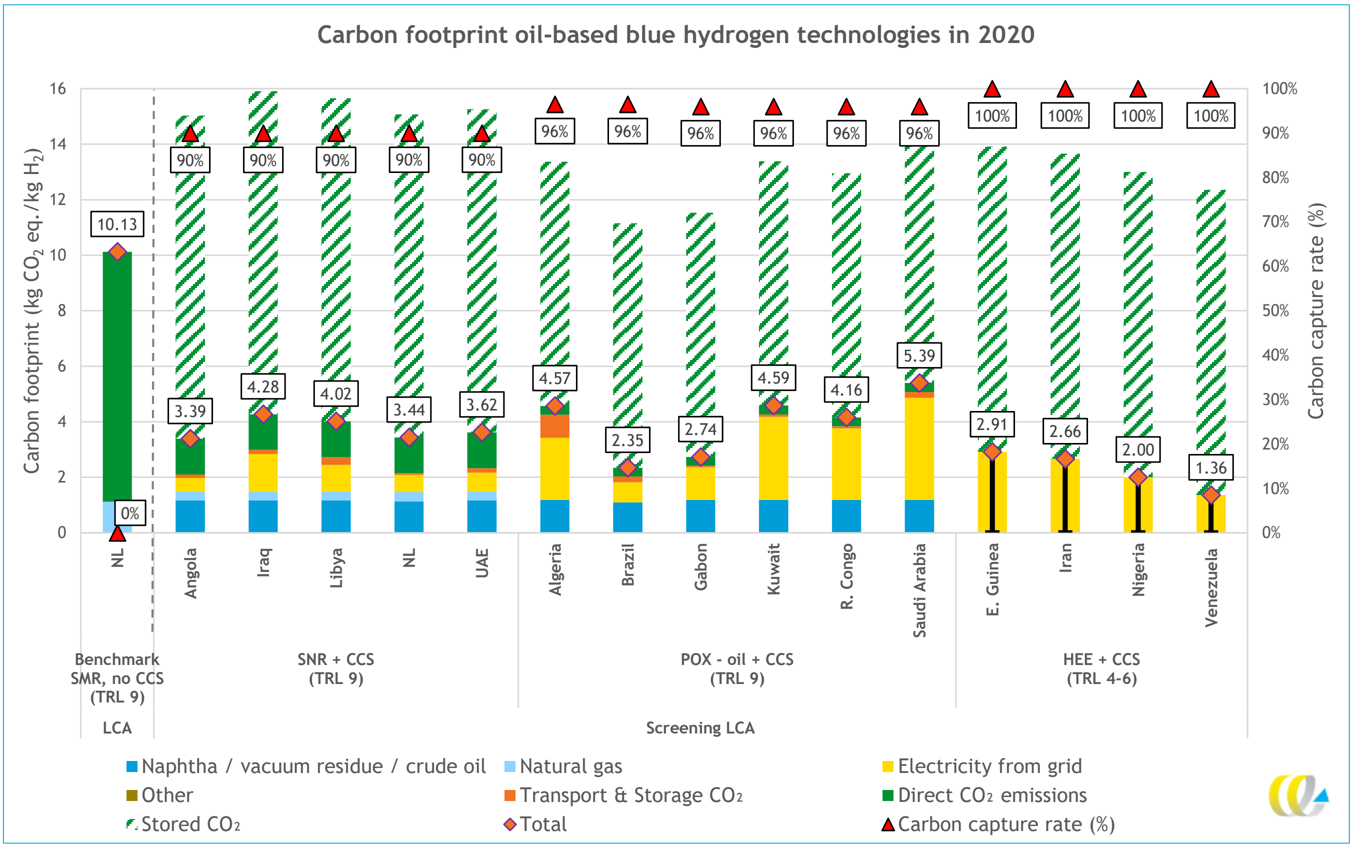

Figure 96: Contribution analysis of the carbon footprint of oil and oil-based blue hydrogen production scenarios and the grey hydrogen benchmark.[250]

Some aspects stand out in the overall carbon footprints of the different technologies. First of all, all blue hydrogen technologies produce hydrogen with a (significantly) lower carbon footprint than the grey hydrogen benchmark: a reduction of the carbon footprint ranging between 47-87% can be achieved in 2020. The reduction of each oil-based blue hydrogen production technology compared to the benchmark is given in Table 16.

Benchmark, Steam Methane Reforming without CCS (TRL 9)

- Generated CO_2 emissions account for the largest share of the carbon footprint of the benchmark. These emissions are mostly related to burning of natural gas as a fuel to heat the process and to the process emissions caused by the reaction which takes place.
- The net electricity (electricity used minus electricity generated) is 0 kWh/kg H_2. Therefore, electricity does not contribute to the total carbon footprint.

Steam Naphtha Reforming with CCS (TRL 9)

- SNR can achieve a carbon footprint reduction between 58-67% compared to the benchmark. Naphtha and direct CO_2-emissions account for the largest contribution to the carbon footprint.
- Compared to the other hydrogen production technologies, the carbon footprint of SNR varies only slightly between countries. This is due to the limited amount of electricity required for the process (of which the carbon footprint varies greatly between countries).
- As the carbon capture rate of SNR is modelled to be 90% (and so not all CO_2 is captured and stored), the direct CO_2 emissions still account for a large share of the carbon footprint. These emissions are

[250] 'Other' includes tap water and water treatment. 'Electricity' includes electricity used for H2 production and compression, electricity generation and O2 production (POX). The error bar of HEE is explained below the figure.

related to burning of natural gas as a fuel to heat the process and to the process emissions caused by the reaction which takes place.

Partial Oxidation with CCS (TRL 9)

- POX can achieve a carbon footprint reduction between 47-77% compared to the benchmark. Electricity and vacuum residue have the largest contribution to the carbon footprint.
- The carbon footprint of this technology is subject to significant regional differences as it requires a large amount of electricity. For example, because the carbon footprint of electricity production in Saudi Arabia is very high (mostly fossil based), this scenario has the highest carbon footprint out of the different scenarios. POX in Brazil, on the other hand, has the second lowest carbon footprint even though the same technology is used. This is because hydropower plants account for approximately 80% of Brazil's domestic electricity generation[251], making it one of the least carbon intensive energy sectors in the world. This demonstrates that, form an environmental perspective, POX with CCS can be a very good option, as long as the carbon footprint of the electricity production is low, whereas if the carbon footprint of electricity production is high, it is preferable to produce hydrogen using a less electricity intensive blue hydrogen technology, such as SNR.

Hygenic Earth Energy + CCS (TRL 4-6)

- HEE can achieve a carbon footprint reduction between 71-78% compared to the benchmark.
- HEE technology has the potential to produce hydrogen with a very low carbon footprint as the crude oil required for the process are used from within the well in which hydrogen is produced (see Section 2.2.2 for a more detailed description). However, this technology is also the most uncertain, due to its low TRL level of 4-6.
- The reforming reaction takes place underground and hydrogen is separated using a membrane. Normally all carbon containing compounds remain in a closed loop within the reservoir. Consequently, HEE does not have any direct CO_2 emissions, nor does the CO_2 have to be captured and transported to a storage location outside the production facility.
- HEE requires electricity for the generation of oxygen and compression of hydrogen. This electricity can be imported from the grid (base case) or generated using the produced hydrogen (alternative).
- In the base case, electricity is the only contributor to the carbon footprint of hydrogen production. As a result, the carbon footprint depends significantly on the country where the electricity is produced.
- The alternative situation is described below and is displayed as an error bar in Figure 96.

Alternative HEE: electricity generated using own hydrogen (error bar)

The carbon footprint of the HEE technologies is shown with an error bar (see Figure 96) because of some inherent uncertainties on how the technology will be deployed due to the low TRL of the technology:

- Based on stakeholder engagement, it is assumed that the HEE hydrogen plant produces its own electricity, by converting part of the produced hydrogen to electricity in a gas turbine. In this case, the electricity is used for the hydrogen plant itself and to produce oxygen. Therefore, both electricity use, and oxygen use do not have a carbon footprint. This is an optimistic scenario, as discussed in Section 6.5. However, connecting the hydrogen plant to the local electricity grid, where available, is technically equally feasible, and this choice is likely a matter of financial optimization, as discussed in Section 2.2.2.
- In this LCA, it was decided to show the scenario where electricity is imported from the grid as the base. The error bar in Figure 96 shows the scenario in which the electricity is produced from hydrogen. In this case, the carbon footprint of the HEE technology becomes zero as there is no external electricity supply which, previously, was the only contributing factor.

Differences between countries

- The carbon footprint of the technologies is subject to regional differences. Even if the same technology is used, differences in the carbon footprint can occur due to regional differences in the carbon footprint

[251] IEA 2020, Brazil

of the used feedstock, fuel, and electricity grid mix. As the availability of country specific environmental data on the feedstocks and fuel is very limited, in most cases the same generic carbon footprint is used for naphtha, vacuum residue, crude oil and natural gas is used (see Appendix, Section 9.4 for more details on the environmental data used). As a result, the carbon footprint variation between the same technology is mostly caused by differences in the electricity production, for which country specific data is available.

- As the carbon footprint of CO_2 T&S only has a limited contribution to the carbon footprint, variations between country specific scenarios also have limited effect. Only in the case of Algeria, where a much larger pipeline (1200 km) is used than in the other countries, the CO_2 T&S has a substantial effect on the total carbon footprint of blue hydrogen production.

Table 16: Reduction of oil-based blue hydrogen production technologies compared to the benchmark (SMR without CCS in the Netherlands)

Technology analysed	Country	Carbon footprint 2020 (kg CO_2 eq./kg H_2)	Reduction compared to benchmark
Benchmark (SMR, no CCS)	The Netherlands	10.13	0%
SNR (TRL 9)	Angola	3.39	67%
	Iraq	4.28	58%
	Libya	4.02	60%
	The Netherlands	3.44	66%
	United Arab Emirates	3.62	64%
POX - oil (TRL 9)	Algeria	4.57	55%
	Brazil	2.35	77%
	Gabon	2.74	73%
	Kuwait	4.59	55%
	Republic of Congo	4.16	59%
	Saudi Arabia	5.39	47%
HEE (TRL 4-6)	Equatorial Guinea	2.91	71%
	Iran	2.66	74%
	Nigeria	2.00	80%
	Venezuela	1.36	87%

6.3.3 Sensitivity Analysis

In this study, the following sensitivity analyses have been carried out in order to assess the effects of changing key parameters on the overall carbon footprint of the different technologies:

- Sensitivity Analysis 1: For all technologies (including the benchmark), the electricity mix has been adjusted to the country specific expected mix in 2030.
- Sensitivity Analysis 2: The carbon capture rate of steam naphtha reforming is increased from 90% to 99%.

- Sensitivity Analysis 3: Local vs shipping CO_2 T&S scenarios are analysed for Angola, Algeria and Kuwait.

These results are presented in the Appendices, Section 9.6.3. Additionally, the effect of other important assumptions made in this study are addressed qualitatively in Section 6.5 'Uncertainties'.

Sensitivity Analysis 1 – Carbon Footprint of Oil-Based Hydrogen Technologies (2030)

As shown in the results in Section 6.3.2, the carbon footprint of electricity production can have a significant impact on the total carbon footprint of blue hydrogen. As most countries have signed the Paris Agreement, the carbon footprint of electricity production in many countries is expected to change in the coming years. This will in turn affect the carbon footprint of the different oil-based blue hydrogen technologies and could change the conclusions drawn in the 2020 analysis. To test this, the expected 2030 carbon footprint of electricity production in the analysed countries has been modelled and a sensitivity analysis of the LCA has been performed.

The expected 2030 carbon footprint of electricity production of each of the countries was estimated and modelled based on country/regional specific estimates found in the World Energy Outlook 2020[107]. Country specific information is used for the Netherlands, based on a detailed report created by the Netherlands Environmental Assessment Agency[252]. This report described the estimated electricity production mix in detail, which makes it possible to create an LCA model. A more detailed description of the models is given in Appendices, Section 9.2.8. A summary of the estimated carbon footprint reductions is given in Table 17. The benchmark technology is kept at natural gas-based SMR without CCS, as this production scenario will likely still be used on a large scale in 2030.

The carbon footprint reduction in 2030 compared to 2020 can vary greatly between countries. As the estimates are often based on regional estimates[253] by the World Energy Outlook 2020[107], this introduces some large uncertainties for specific countries. For example, the carbon footprint reduction of electricity production in Saudi Arabia, Kuwait and United Arab Emirates (Table 17) are based on the estimated reduction in the Middle East. This is a rough estimate, as large variations between countries in the same region can be expected. Saudi Arabia, for example, has recently signed the 'Saudi Green Initiative', where they formulate the ambitious goal of transforming their energy mix from the current 0.3% renewables to 50% renewables in the energy mix by 2030. Naturally, if this goal became reality in 2030, the carbon footprint of POX in Saudi Arabia would be significantly lower than is estimated in this sensitivity analysis. The results in this sensitivity analysis should therefore mostly be used to show the significant importance of having a sustainable electricity mix when producing blue hydrogen, instead of focussing on the exact numbers.

Table 17: Estimated carbon footprint reduction of electricity 2030 compared to 2020

Countries	Estimated carbon footprint reduction electricity 2030 compared to 2020	Source
the Netherlands	66.7%	(PBL, 2020)
Brazil	27.6%	World Energy Outlook 2020, Table A.3, Brazil (IEA, 2020)
Venezuela	26.2%	World Energy Outlook 2020, Table A.3, Central and South America (IEA, 2020)
Iran, Iraq, Kuwait, Saudi Arabia, United Arab Emirates	11.6%	World Energy Outlook 2020, Table A.3, Middle East (IEA, 2020)
Algeria, Libya, Angola, Equatorial Guinea, Gabon, Nigeria, Republic of Congo	24.6%	World Energy Outlook 2020, Table A.3, West Africa (IEA, 2020)

[252] PBL 2020, Klimaat- en Energieverkenning 2020
[253] Only for the Netherlands and Brazil, country specific data is used

The results of this sensitivity analysis are presented in Figure 97. The results are discussed below the figure.

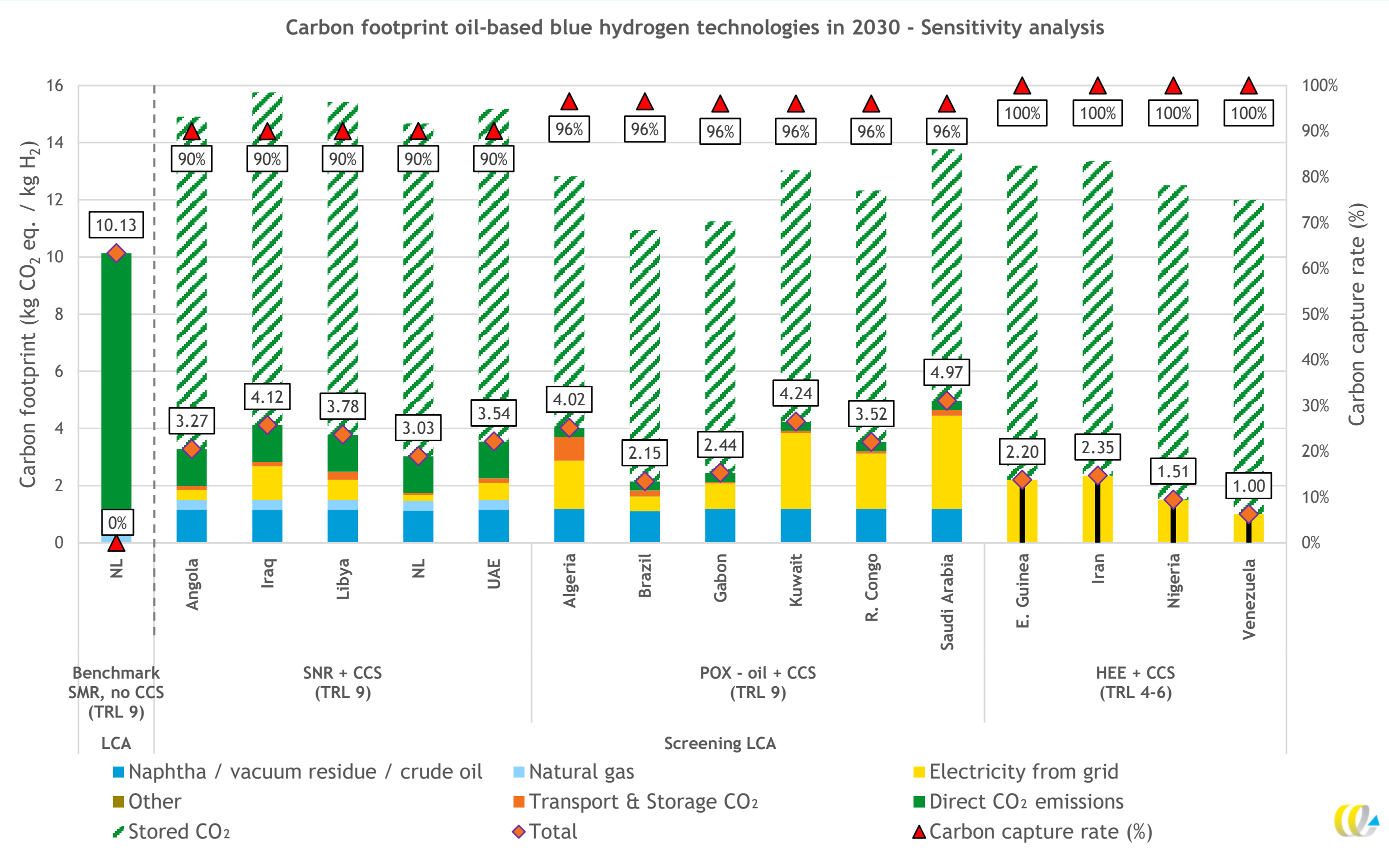

Figure 97: Sensitivity Analysis 1 – Carbon footprint oil-based blue hydrogen technologies with estimated country specific carbon footprint of electricity 2030[254]

The following conclusions can be drawn from this analysis:

- As the benchmark has an electricity use of net 0 kWh/kg H_2, no change occurs in its 2030 carbon footprint compared to the 2020 carbon footprint. Therefore, the carbon footprints of the blue hydrogen technologies reduce further compared to that of the benchmark to between 51%-90%.
- The carbon footprint of the electricity production is a big contributor to the total carbon footprint. This shows that having a sustainable electricity source is important when producing blue hydrogen. World Energy Outlook estimated that in some regions the electricity mix will still have a large carbon footprint as the mix remains largely fossil based in 2030. As discussed in the beginning of the section, the carbon footprint of the electricity mix of countries can still vary greatly within the same region and therefore the given results mainly show the significance of a low carbon electricity mix.
- Changes to the carbon footprint of the electricity production have the biggest effect on POX and HEE, as these technologies require a large amount of electricity compared to SNR.
- As the carbon footprint of electricity decreases, the relative contribution of other factors, such as feedstock use, and direct CO_2 emissions becomes more relevant.

Sensitivity Analysis 2 – Steam Naphtha Reforming with 99% Capture Rate

As shown in the results in Section 6.3.2, the carbon capture rate very likely has a significant impact on the total carbon footprint of blue hydrogen. To investigate the importance of the carbon capture rate, this sensitivity analysis shows the carbon footprint of SNR in the Netherlands when the carbon capture rate is increased from 90% to 99%. As capturing more CO_2 leads to higher energy usage, an illustrative increase in the electricity

[254] See Section 6.3.2 for the explanation of the error bar of HEE.

consumption of the hydrogen production by 10% has been assumed. The results of this sensitivity analysis are presented in Figure 98. The results are discussed below the figure.

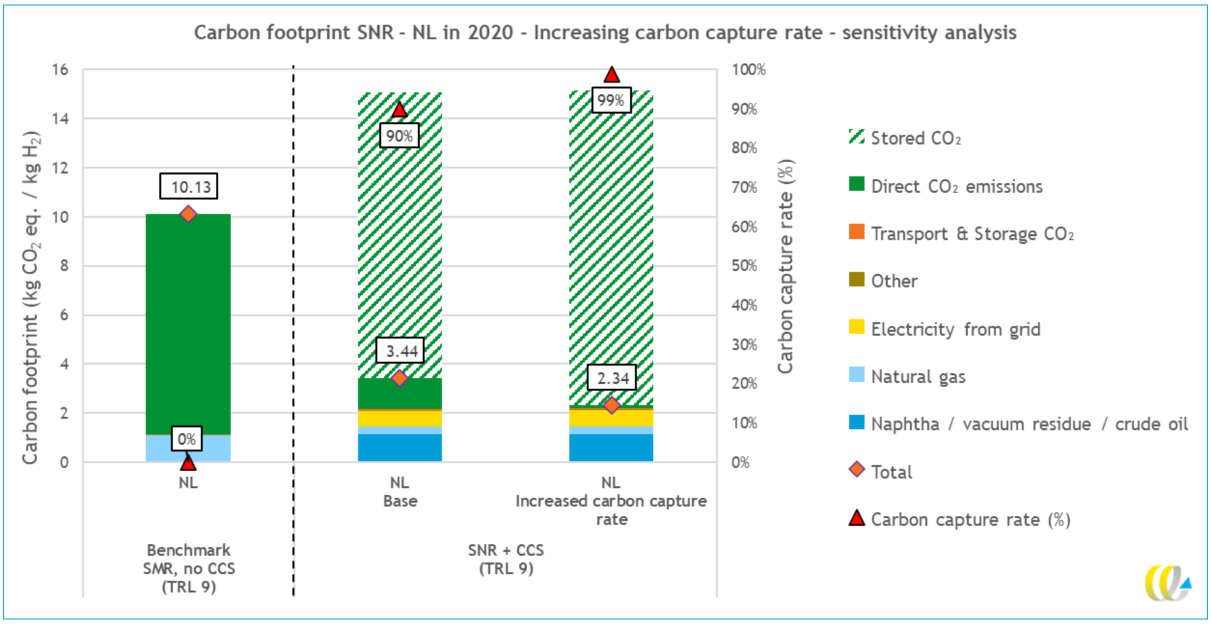

Figure 98: Sensitivity Analysis 2 – Carbon footprint of blue hydrogen produced using steam naphtha reforming – carbon capture rate increased to 99%

The following conclusions can be drawn from this analysis:

- The carbon capture rate has significant effect on the carbon footprint of blue hydrogen production technologies. A higher carbon capture rate decreases the carbon footprint significantly, even if the electricity requirements increase by 10%.
    - This is illustrated for SNR in this sensitivity analysis. However, changes in the carbon capture rate are possible for each blue hydrogen production technology in this study, and therefore the conclusion that changing the carbon capture rate has a significant effect on the overall carbon footprint is relevant for all blue hydrogen technologies.
- The overall carbon footprint reduction of SNR in the Netherlands compared to the benchmark is lowered from 66% to 77% when increasing the carbon capture rate from 90-99% (and assuming an increase in electricity use of 10%).

Sensitivity Analysis 3 – Alternative CO_2 T&S Scenarios (local vs shipping)

In the results presented in Section 6.3.2, local CO_2 T&S scenarios are analysed using pipelines. In this sensitivity analysis, shipping CO_2 T&S routes are investigated. The goal of this sensitivity analysis is to illustrate the effect that different CO_2 T&S scenarios (local vs shipping) can have on the total carbon footprint of blue hydrogen production technologies. The CO_2 T&S scenarios are described in the Appendices, Section 9.2.5. Table 18 provides a summary of the T&S scenarios investigated in this sensitivity analyses. The assumption used to model these scenarios are described in the Appendices, Section 9.2.5.

Table 18: Distances CO_2 T&S Scenarios (local vs shipping)

Country	Scenario	Onshore pipeline (km)	Shipping (km)	Offshore pipeline (km)
Angola	Local CO_2 T&S (base)	10	-	200
	Shipping CO_2 T&S	10	9500	20
Algeria	Local CO_2 T&S (base)	1200	-	-
	Shipping CO_2 T&S scenario 1	5	3750	20
	Shipping CO_2 T&S scenario 2	5	800	20
Kuwait	Local CO_2 T&S (base)	5	-	50
	Shipping CO_2 T&S	5	450	300

The results of this sensitivity analysis are presented in Figure 99. The results are discussed below the figure.

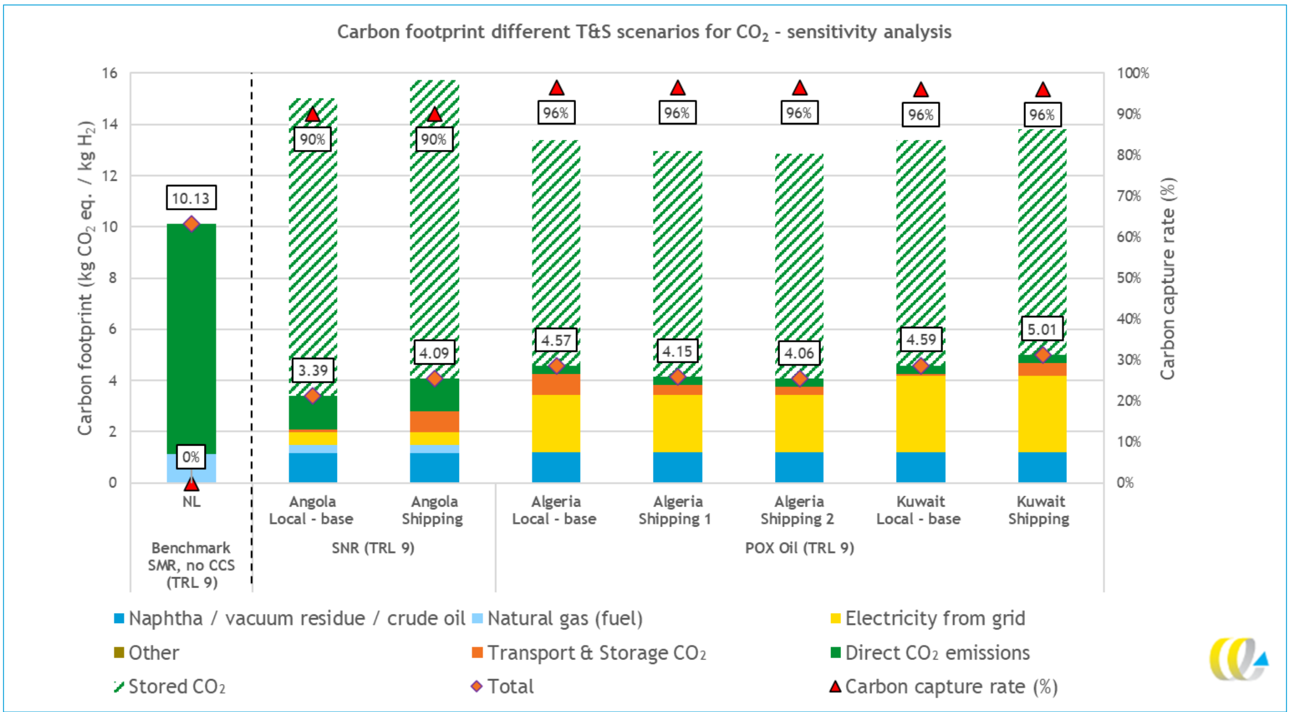

Figure 99: Sensitivity analysis 3 – Carbon footprint of blue hydrogen produced using POX in Algeria – the effects of three different scenarios for transport and storage of captured CO_2

The following conclusions can be drawn from this analysis:

- This sensitivity analysis shows that both transport distance and modality chosen for the captured CO_2 can have a substantial effect on the carbon footprint of a technology. The preferred transport and storage scenario is different per case, depending on the transport distances.
- Local transport and storage of CO_2 scenarios (via pipelines) generally have a lower carbon footprint than the shipping scenario if the CO_2 storage location is close-by and therefore, relatively short

pipelines are required. If the CO_2 is shipped instead of stored local, the contribution of the CO_2 T&S on the total carbon footprint increases from 2 to 10% for Kuwait and from 4 to 20% for Angola. This is the case for the base scenarios of Angola and Kuwait, but is applicable for other countries as well.

- Transport by ship instead of pipeline can decrease the carbon footprint of CO_2 transport and storage if it prevents the construction of large pipelines. In the base scenario for Algeria, where 1.200 km of pipeline is required for 'local' storage, the transport and storage of CO_2 contributes to 18% of the overall carbon footprint due to large pipelines. In scenario 2 and 3, where the CO_2 is shipped to another location, this becomes 10% and 8%, respectively.

6.4 Comparing results

In this section, the LCA results for oil-based blue hydrogen routes in this study are compared with the parallel study done on natural gas-based blue hydrogen production routes (Section 6.4.1). Furthermore, the results are compared to the alkaline electrolysis production route (Section 6.4.2).

6.4.1 Comparison with Parallel Study on Natural Gas-Based Hydrogen Production Route

In the parallel study[255] similar LCAs are carried out for four different natural gas-based hydrogen production technologies in the Netherlands. Even though both studies use the same LCA methodology, it is not possible to draw a direct comparison between the technologies in this study and the ones in the parallel study due to differences in region, carbon capture rate, purity of hydrogen, assumptions, and uncertainties. It is, however, possible to make some cautious remarks on how the technologies in the studies compare.

- All the studied blue hydrogen production scenarios (both oil- and natural gas-based) have significantly lower carbon footprint than the benchmark (SMR without CCS), as more than 90% of the – otherwise emitted – CO_2 is captured and stored. The blue hydrogen production technologies with TRL 7-9, have a carbon footprint reduction of 47%-77% compared to the benchmark, depending on the selected technology.
- All other things considered equal, hydrogen production routes that use oil as a feedstock instead of natural gas, generally have a higher carbon footprint because of the higher carbon-to-hydrogen ratio of the oil feedstock. This is one of the reasons why for example SMR with CCS (in the Netherlands) has a 19% lower carbon footprint than SNR with CCS (in the Netherlands). Compared to the benchmark however, both technologies allow for a high carbon footprint reduction (73% reduction for SMR+CSS and 66% reduction for SNR+CCS).
- Both the natural gas-based and oil-based hydrogen production technologies have the potential to further reduce their carbon footprint in the future, for example, by reducing the carbon footprint of electricity production. ESMR (natural gas-based) and HEE (oil-based) have the highest potential for carbon footprint reduction in the future. These technologies, however, also have the lowest TRL and, consequently, the highest uncertainties.

6.4.2 Comparison with Alkaline Electrolysis Production Route

Another hydrogen production route is the production of hydrogen using electrolysis. There are different type of electrolysis technologies, but the most common at this moment is the alkaline electrolysis. JEC reported that for this hydrogen production route, 51.4 kWh/kg H_2 is required (efficiency of 65%). Further compression to 200 bar requires an additional 1.1 kWh/kg H_2. Based on these inputs, the carbon footprint for hydrogen production via alkaline electrolysis can be calculated.

[255] Blue Hydrogen Roadmap, Element Energy & CE Delft, 2021

As the alkaline electrolysis process requires a large amount of electricity, the carbon footprint of 1 kg hydrogen depends on the carbon footprint of electricity production, and therefore depends heavily on the origin of electricity (fossil based, country mix or renewable electricity[256]) and period (e.g., 2020 vs 2030).

For example, renewable electricity produced from Wind & Solar in the Netherlands in 2020 has a carbon footprint of 0.0329 kg CO2 eq./kWh[257], whereas the country mix is 0.479 kg CO_2 eq./kWh[257], resulting in a carbon footprint of 1.723 and 25.06 kg CO_2 eq./kg H_2, respectively.[258] The difference in carbon footprint per country can be illustrated when looking at Brazil as the carbon footprint of the electricity mix in Brazil is much lower than in the Netherlands (0.196 kg CO_2 eq./kWh compared to 0.479), resulting in a carbon footprint of 10.2 kg CO_2 eq./kg H_2.[259]

These results show that electrolysis has the potential to reduce the carbon footprint of hydrogen production compared to benchmark by 80-90%, which is higher than most of the blue hydrogen production technologies.

6.5 Uncertainties

In this section the main limitations (Section 6.5.1) and uncertainties (Section 6.5.2) of the LCA results are discussed.

6.5.1 Limitations

- As discussed in Section 6.1.1, the **system boundaries** of the LCAs performed in this study are **cradle-to-gate**. This means it does not include the transport of hydrogen to its end-use location and the end-use itself. The reason for this is that hydrogen has many different applications: as a feedstock in industry, as an energy carrier for both heat and power production and a fuel in transport. In the present study this approach is sufficient, as the focus is on the difference between different hydrogen production technologies. If one were to compare the environmental performance of hydrogen to (conventional) alternatives in one of these specific applications, the transportation and end-use of hydrogen must be considered as well. Additionally, depending on the purity of the hydrogen assumed for each of the technologies in the present study and requirements for different end-uses, additional purification steps might need to be included as well.
- The **capital goods of the foreground system** (i.e., equipment/infrastructure required in the hydrogen production facility) are **not included** in the scope of this LCA. Based on a comparable LCA study on blue hydrogen production[244], the carbon footprint of these capital goods is expected to be very limited.
- The **carbon capture rates** of all blue hydrogen technologies have a large impact on the overall carbon footprint. The carbon capture rate used for each of the scenarios in this study is based on publicly available data. It is not completely fair to compare different technologies with different carbon capture rates, as when designing a production scenario, it is possible to adapt the capture rate by changing the capture technology used. A downside of increasing the carbon capture rate, is that this increases the energy demand and auxiliary usage. This trade-off is investigated in a sensitivity analysis (Section 6.1.5) where the carbon capture rate of SNR is increased from 90% to 99%.
- As discussed in Section 2.1, there are differences in **purity** of the produced hydrogen. Even though only hydrogen production scenarios are chosen which produce hydrogen with a purity higher than 97%, the potential difference in purity (97%-99.999%) still limits the comparability of the scenarios. However, it is expected that the differences in purity do not significantly affect the LCA result, as additional purification steps will likely have limited effects on the LCA.
- As discussed in Section 6.3.2, the LCA results of the hydrogen production scenarios is highly dependent on **regional differences** (e.g., the carbon footprint of electricity production in Brazil is much

[256] In this study, electricity is only considered to be renewable when there is a direct link between the renewable electricity production and hydrogen production facility.
[257] CE Delft 2020, Emission indicators electricity
[258] See Appendix 9.2.8 for more information on the carbon footprint of electricity production in the Netherlands.
[259] Source: LCA database Ecoinvent v3.6 - ‘Electricity, high voltage {BR}| market group for electricity, high voltage’

lower than in the other countries). Consequently, the comparability between the hydrogen production scenarios is limited.

6.5.2 Uncertainties

This section lists the main uncertainties for each hydrogen production scenario and CCS. These uncertainties are mostly the result of the assumptions related to the data, as presented in the Appendices, Section 9.2.

Steam Methane Reforming Without CCS

- The data quality of the benchmark (SMR without CCS) is very high because of high TRL and excellent data availability. No substantial uncertainties have been identified.

Steam Naphtha Reforming

- Even though the technology has high TRL, there is limited amount of data available as the dominant technology associated with steam reforming is SMR.
- In this study, as described in the Appendices, (Section 9.2), some of the data used to model the SNR carbon footprint is based on using SMR as a proxy. This does introduce uncertainties, but due to the near-identical production configuration, it is an appropriate assumption.

Partial Oxidation

- Heavy fuel oil is used as a proxy for vacuum residue in the LCA modelling, due to lack of data in the LCA database (Ecoinvent v3.6). POX technology allows a wide range of feedstock to be used. The carbon footprint of the different feedstocks varies. Consequently, the total carbon footprint of POX can be different when another type of feedstock is used.
- As explained in the Appendices (Section 9.2), the electricity demand of an ASU to produce 1 kg of O_2 is different in different sources, resulting in a range. The quantity used in this study is based on a recent value (representing an efficient ASU), is at the lower end of the range. The O_2-related electricity demand has significant impact on the carbon footprint and therefore LCA results could be an underestimation if less efficient ASUs are used.

Hygenic Earth Energy

- Limited data availability as data comes only from Proton Technologies. Furthermore, the technology has low TRL which introduces uncertainties on how the technology will be deployed and thus on the input and output data used.
- Based on the data received for this technology, it is assumed there are no leakages of CO_2, methane or other hydrocarbons to atmosphere. Due to the low TRL of the technology, this is not based on practice and introduces uncertainty, Given the common practices in the oil and gas industry, this is an optimistic assumption.
- It is assumed no flaring or venting from the reservoir occurs. Given the common practices in the oil and gas industry, this is an optimistic assumption.
- The palladium membrane is said to last as long as the lifetime of the well and as such is not taken it into account for the impact assessment (as it is considered part of the capital goods). However, as this technology has not been commercially implemented yet, this is an assumption. If the membrane were replaced more often, the impact of the production of the membrane(s) should be considered in the LCA.
- A 100% selectivity of the membrane is assumed. Additionally, no other compounds can pass through the membrane. If carbon-containing compounds do escape, separation and reinjection is necessary to prevent an increase in carbon footprint.
- The initial energy required to start up the hydrogen production is not included in this study. While this energy may be significant, there is no data available on this topic.
- As explained in Section 6.3.2, two different electricity generation scenarios have been analysed for HEE (from its own H_2 and from the grid). The uncertainty on how electricity is produced has significant effects in the carbon footprint.

- Other options for electricity production are on-site generation by combustion of raw syngas from the reservoir in a gas turbine, or by combustion of imported fuels such as diesel in an electricity generator. These scenarios are not analysed. However, both options - without subsequent capture and reinjection of CO_2 – will very likely (significantly) increase the carbon footprint of the hydrogen produced by HEE.

Capturing CO_2

- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy used for the carbon capture process has been considered. Based on a comparable LCA study on blue hydrogen production[244], the carbon footprint of auxiliaries and absorbents is expected to be very limited.
- In this study, due to data availability, not all scenarios were analysed using the same carbon capture rate. As this has significant impact of the carbon footprint of the hydrogen produced, this introduces an uncertainty in the results of this study. The sensitivity of the results to changing the carbon capture rate of the SNR scenarios was estimated in a sensitivity analysis (see Section 6.3.3).

CO_2 Transportation and Storage

- Pipelines are modelled as onshore pipelines in the LCA analysis. The production of offshore pipelines could result in a larger carbon footprint per km pipeline. This assumption mostly affects POX – Brazil as this hydrogen production scenario mostly uses offshore pipelines. However, this assumption will likely not have a large impact on the total carbon footprint of the hydrogen production scenarios as the overall impact of CO_2 T&S is limited.
- Pipeline compressor power is a function of flow rate, pipeline utilisation, pressure drop and compressor efficiency[169]. The pipeline diameter is a function of flowrate and pipeline length. The final combination of compressor power and pipeline diameter are such that a pressure drop of 1MPa is maintained across the pipeline. As a result, the compressor power for each technology is fixed whilst the pipeline diameter varies. This is presented in the Appendices, Section 9.2.7.
- In the LCA model, the pipeline that is used for CO_2 transportation is modelled as a natural gas pipeline as the LCA database contains no information on pipelines for CO_2 transport. As the diameter and thickness of the CO_2 pipeline is different than the natural gas pipeline, the pipeline is scaled based on the differences in the area (intersection) of the pipelines. This scaling method gives a rough estimation and introduces uncertainty. However, this estimation likely won't have a large impact on the total carbon footprint of the hydrogen production scenarios as the overall impact of the CO_2 T&S is limited.

Methane leakages

- Methane leakages can occur when producing and transporting natural gas. Methane leakages are included in our analysis based on the environmental database (Ecoinvent v3.6).
  - In this database, the methane leakages during extraction/production of natural gas from a gas field vary for each region/country. Methane leakage related to extraction/production are included in every case; however it is not always clear what value has been used exactly. For example, the Ecoinvent process for Algerian natural gas mentions leakage during respectively exploitation and production is estimated at 0.6% and 0.13% based on European sources from 1990-2000. It is not clear whether these leakage values have been used solely for methane or for all leaked compounds.
  - Additionally, the methane leakages during transport are based on the estimation that ~0.2% methane leaks per 1000 km transport via pipeline. As the natural gas (used as fuel for the oil-based blue hydrogen technologies) is imported from different countries, the methane leakage differs per country of origin.
- Currently, a lot of research is done on the amount of methane leakages involved in the production and transportation of natural gas, and some recent research suggests methane leakages to be higher than the estimate used in Ecoinvent v3.6. Additionally, the amount of methane leakage varies between locations and technologies. However, there is no scientific consensus yet on the exact values per technology and location. If methane leakage is higher than in Ecoinvent processes, this could have a substantial effect on the resulting carbon footprint of blue hydrogen production technologies which use

natural gas. It is recommended to follow developments regarding this topic and keep this is mind when using the LCA results.

7 Key Enablers, Challenges and Barriers

This report has identified a series of flagship projects (including Porthos, Athos and Acorn), policy measures (including the EU's RED II and the United States' 45Q tax credits), and trends via hydrogen strategies and global uptake that demonstrate that there is a pathway to wide-spread deployment for blue hydrogen technologies. However, the blue hydrogen value chain still requires support in the form of policy design and market creation mechanisms in order to drive investment.

Although dependent on the simultaneous implementation of short to medium term incentives in other parts of the value chain, blue hydrogen production is the first stage needed to catalyse growth of hydrogen. Some key barriers and their enabling support mechanisms for production are listed below:

- Production of blue hydrogen via technologies that use oil and / or oil-derived products have not yet been demonstrated at scale. The successful deployment of these technologies relies on a multiplicity of factors: proving technical and financial viability; validating the CO_2 footprint; building local awareness and skills; assessing integration with the wider regional supply chains; and maximising learnings through similar projects in other regions with progressed hydrogen demonstration projects. **Government grants**, **risk mitigation measures** and **private industry funding** are essential to drive blue hydrogen demonstration projects forward. This is the first stage towards long-term, unsubsidised blue hydrogen production.

Box 3 Business Models for Blue Hydrogen Production

Blue hydrogen production technologies have not reached the commercialisation stage, and unfavourably low carbon prices reduce blue hydrogen competitiveness against alternatives with high carbon intensities. In some regions, complete lack of a carbon price further exacerbates this issue. These externalities are most effectively addressed by developing **suitable blue hydrogen business models.**

Taking the UK as a case study, the UK Government is in an advanced stage of business model development to support blue hydrogen[260]. Currently, four broad categories are under consideration[261]. The options cover direct support for blue hydrogen producers, as well as indirect support by incentivising growth of hydrogen demand. Therefore, potential business models can lead to catalyse supply as well as long-term demand:

- **Contractual payments to producers**, where the hydrogen producer receives a subsidy to cover the cost difference between blue hydrogen production and high-carbon counterfactual. This category includes a Contract for Difference and Premium Payment models.
- **Regulated returns**, where the business model allows the producer to earn a regulated return on the costs. This category includes Regulated Asset Base and Cap and Floor Models.
- **Obligations**, where an obligation is imposed on non-production parties, such as end users, to supply or use a certain amount of low carbon hydrogen.
- **End user subsidies**, where a subsidy is provided to end users to consume blue hydrogen for a certain application.

Suitable business models will vary between locations, but optimal business models should consider that fuel costs comprise the largest portion of the cost structure of blue hydrogen production.

The Netherlands is another example of the implementation of such support, with its SDE++ scheme. Companies are able to register for subsidies (a national programme for CO_2 reduction) that will ensure the companies remain competitive whilst capturing emissions[262].

- Blue hydrogen facilities require the deployment of CCS infrastructure to transport and store the CO_2. This limits the number of suitable locations for blue hydrogen production and leads to additional

[260] BEIS 2020, Carbon Capture, Usage and Storage. A Government Response on potential business models for Carbon Capture, Usage and Storage
[261] Frontier Economics for BEIS 2020: Business Models for Low Carbon Hydrogen Production
[262] Porthos 2021, Biggest Dutch project for CO2 reduction, Porthos, is on schedule

production costs. **Development of regional strategies for CCS uptake in other sectors** such as industry and power can minimise uncertainty for investors and reduce cross-chain costs. A CCS strategy would lead to optimised CCS infrastructure sharing **if blue hydrogen facilities are collocated to existing industry in clusters**, where potential for carbon capture deployment is largest.

Areas of hydrogen demand, particularly in the near term (as explored in Section 3), may not necessarily be located adjacent to optimal locations for blue hydrogen production. This implies that support mechanisms are to ensure connection of production to demand points. In the short to medium term, materialising these connections may require international trade of hydrogen to areas with more developed hydrogen strategies and with proven end-uses for hydrogen. Exporting hydrogen faces increased barriers as value chains are geographically scaled up, some of these key barriers and their enabling support mechanisms are listed below:

- Investment in blue hydrogen production capacity requires not just certainty of hydrogen demand but also certainty of value chain integrability. This can be particularly challenging when ensuring cross-border hydrogen trading. To limit these challenges, blue hydrogen producing countries can **target regions with an established national hydrogen strategy,** such as certain regions in Europe, Northeast Asia and Western USA. This could support the **development of international hydrogen trade projects**. This would involve an increased understanding of the international scale and timeframe of hydrogen demand can be translated into tangible and measurable requirements for blue hydrogen production, such as installed capacity. **Increased global standardisation and increased coordination** through collaborative international projects can also help blue hydrogen producers understand the implications of exporting for the downstream value chain, such as the requirements for transport, conversion, and reconversion (liquefied hydrogen, ammonia, or liquid organic hydrogen carriers). This can help plan for the supporting infrastructure accordingly, not just in the origin country but also in the destination country. **This should also include international standardisation of hydrogen definitions based on carbon intensity rather than production technology.**

- Certain countries with published national hydrogen strategies have stated their long-term preference for hydrogen imports in the form of green hydrogen. Moreover, some regions may be open to blue hydrogen imports but may articulate in their hydrogen strategies specific emissions intensity criteria for blue hydrogen[263]. Exporters can mitigate this by **participating in international trade agreements**, where the currently economic competitive advantage of blue hydrogen production against the higher costs of green hydrogen is used as a leverage to guarantee offtake agreements and ensure contractual arrangements.

- In order to reduce cross-chain costs and increase competitiveness, supporting a hydrogen exports industry may require the repurposing of existing operational infrastructure, such as natural gas pipelines or light hydrocarbon storage facilities. Many potential blue hydrogen exporters with an oil and gas legacy currently export LNG via ports, which offers important synergies with future hydrogen exports by potentially building on existing skills and supply chains. Further, existing facilities e.g., ports could be expanded to accommodate for hydrogen export activities. Incentivising infrastructure repurposing may require **supporting policies and providing infrastructure operators with certainty of continued operation**, something which can be facilitated by implementing the recommendations above.

- Many of the countries with exceptional potential for blue hydrogen production currently export high-carbon commodities derived from oil and gas. However, it is expected that developed countries will create, in the long-term, an international market for low carbon commodities complying with their decarbonisation targets, where not only process emissions but also lifecycle emissions are accounted for. It is thus crucial that producers maintain their international competitive position by producing low-cost, low carbon commodities. Governments can achieve this by **incentivising production pathways and technologies which use blue hydrogen (which abate CO_2 emissions beyond a specified threshold) as a feedstock** to produce low carbon commodities, allowing producers to competitively

[263] For example, the UK Government is in the process of defining a 'low-carbon hydrogen standard' that will include hydrogen production routes with a carbon intensity below a yet to be determined gCO_{2e}/MJ_{LHV} delivered H_2– UK Government 2021, Designing a UK low carbon hydrogen standard

enter in the low carbon commodity market. As well as coming from local governments, where initial hydrogen demand is expected to be small, governments which import significant quantities of hydrogen in the near-to-medium term could support the widespread deployment of these technologies in developing regions via financing, technology transfer and sharing of skills and learnings.

- In order to export low carbon commodities, including blue hydrogen, there may be a long-term requirement to abate of CO_2 emissions in other stages of the supply chain, such as fugitive emissions in the upstream oil production stage or in feedstock processing. In the future, public and private stakeholders may address this issue by implementing mechanisms which increase upstream efficiency or mitigate well-to-gate emissions. It is important to ensure that the methodologies for calculating these emissions are harmonised to avoid double counting emission savings from production processes.

In the longer term, as blue hydrogen production technologies mature and as value chains become familiarised with CO_2 T&S methods, localised demand for blue hydrogen could potentially develop in emerging regions in addition to international trade. In such a case, a new set of challenges will arise. Addressing these will require national governments to introduce region-specific support mechanisms. Some key barriers and their enabling support mechanisms are listed below:

- Blue hydrogen consumption (like other forms of low carbon hydrogen consumption) is currently less cost-effective than incumbent high-carbon fuels and the economic gap can vary in each sector. Industry may face increased fuel switching costs as the lower duties and the lower fuel costs resulting from large scale demand act as inherent incentives for fossil fuel use in the sector. **Policies that incentivise the use of low carbon hydrogen based on carbon intensity, ensuring technology neutrality, across sectors by fuel switching** are therefore needed:
    - Low carbon hydrogen fuel switching can lead to the deep decarbonisation of high-emitting sectors such as heavy industry. However, industry needs to see commitment from policymakers to support wider regional ambitions to move towards blue hydrogen fuel switching. This includes **wide scale decarbonisation in the long term** that adheres to the provisions and principles of the Paris Agreement in the context of sustainable development.
    - Governments can provide **capital support for covering a portion of the capital investment required to replace existing equipment** for low carbon hydrogen ready alternatives, such as industrial burners and domestic boilers.
    - **Governments can implement obligations,** which are an effective solution for the phased introduction of low carbon hydrogen in end-use applications. This can serve to demonstrate the safety and technical viability whilst promoting commercialisation.
    - **End-user subsidies** can be used to incentivise hydrogen uptake in various applications by reducing the premium gap and by solidifying the expected return on investment for certain applications where new equipment is needed.
- Significant demand for blue hydrogen should also arise from replacing current fossil fuel energy uses with hydrogen (i.e., hydrogen for heat and DRI), as opposed to new energy uses (new industrial installations). As fuel switching is not a 'no-regrets' decarbonisation option, this requires governments to **establish or strengthen national decarbonisation targets** which create the appropriate policy environment for low carbon hydrogen fuel switching.
- Investment in blue hydrogen production facilities, using oil and oil-based products, requires certainty of demand for the blue hydrogen output during the lifetime of the plant. However, deployment of green hydrogen production projects and blue hydrogen projects which use gas as a feedstock in the future could also be expected. The possibility of decreasing utilisation factors due to competition with these other production methods could deter investment into oil-based blue hydrogen projects. The **development of national or regional hydrogen strategies/roadmaps**, which provide estimates about potential scenarios for blue and green hydrogen production in the long term, can help i) investors

measure the level of risk and ii) project developers better understand production capacity requirements.

In the longer term, the availability and price of certain feedstocks, such as naphtha and heavy oil fractions, may change in the future as global demand for refined products declines. Production of blue hydrogen suggests that use of distillates with a decreasing demand could be diverted towards blue hydrogen production. However, some of these production methods are currently at low stages of technological maturity, highlighting the **need for public and private stakeholders to support their timely demonstration ahead of commercialisation**.

8 Comparative Assessment of the Results

This final section compares the different production technologies analysed in this report and how competitive these production methods are with other options on / coming to the market. This concludes with a series of recommendations for progressing hydrogen produced from oil and / or oil-derived products.

8.1 Emerging Opportunities from Oil-Derived Hydrogen

8.1.1 Deployment Potential in the 2020s

For the ‘base case’ scenarios in 2020 (outlined in detail in Section 5.2), all oil-based hydrogen production technologies have a higher cost than the reference grey hydrogen production case in the Netherlands via steam methane reformation. It is important to note that this is expected for all blue and green hydrogen production technologies. This is due to:

- High and variable feedstock costs which, in all but one case (SNR in the UAE), are greater than the LCOH for SMR without CCUS
- The high H_2 distribution and CO_2 T&S costs that arise from the long distances to hydrogen ready markets and CCS projects still in their development stages, respectively.

HEE in Venezuela has the lowest LCOH of all oil-based technologies analysed, despite being 60% more expensive than the reference case. However, because the HEE technology has a low TRL, the results are still uncertain and should not be directly compared with SNR and POX.

SNR is the most expensive oil-based hydrogen production technology with an average LCOH of 4.91 €/kgH_2 when delivered to its nearest major market, whilst POX and HEE have average LCOH of 4.45 €/kgH_2 and 3.60 €/kgH_2, respectively. Hydrogen distribution is a major cost component for all technologies other than SNR in the Netherlands (where hydrogen is used locally), whilst CO_2 T&S costs are also significant for both SNR and POX technologies (whereas CCS is not required as part of the HEE process).

For the ‘lowest case’ scenarios in 2020, SNR and POX remain higher cost than the reference case in all scenarios. However, HEE is lower cost than the reference case in all scenarios other than Nigeria. Significant cost reductions can be achieved for both the POX and HEE technologies that arise where:

- Vacuum residue is a waste product and either has no value or the operator has to pay for its disposal (partial oxidation); or
- The oil in the reservoir has no commercial value (Hygenic Earth Energy).

For all cases, reducing the cost of hydrogen distribution and CO_2 T&S is achieved by reducing transport distances from the source of production. However, steam naphtha reforming processes remain high cost due to the high value of the feedstock, particularly in the Netherlands.

8.1.2 Long-Term Technoeconomic Assessment Comparison

The situation is 2050 is very different. The SMR incumbent is significantly exposed to high carbon prices and so it becomes more prudent to compare with other blue hydrogen production technologies, such as SMR with CCS here.

For the ‘lowest case’ scenarios in 2050 (outlined in detail in the Appendix, Section 9.6.1 – this scenario assumes that each of the cost components have been optimised to provide the lowest LCOH for all oil-based production technologies), eleven out of the fifteen oil-based hydrogen production technologies, which distribute hydrogen locally, are lower cost than the local consumption of blue hydrogen derived from SMR in in the Netherlands.

- SNR in the Netherlands is still the highest cost out of these options, due to high feedstock costs. The UAE is the only country where SNR is lower cost than the SMR with CCS option in the Netherlands.

- Feedstock costs have been minimised for POX and HEE production technologies where it is assumed that waste products are utilised and therefore have no economic value. This is not possible for SNR which relies on naphtha feedstock, which is a refined oil product.
- For all scenarios, it is assumed that increased hydrogen demand will be provided by local end-users. This significantly reduces the costs of hydrogen distribution and storage.
- Carbon pricing is also predicted to be a more significant cost component in 2050 as shown for the reference case without CCS. This, however, also becomes a significant cost component for SNR technology, which is more sensitive to increasing carbon prices due to higher emissions produced in comparison to the POX and HEE processes.

8.1.3 Cost of CO_2 Abatement CO_2

Cost of CO_2 Abatement Comparison 2020

The cost of CO_2 abatement was compared against the SMR without CCS counterfactual case in the Netherlands as shown in Figure 100. This is based on a 25-year operational lifetime, starting in 2020. For all hydrogen production technologies, the carbon price reduces the cost of CO_2 avoidance at both gateway 1 and 2.

- **Gateway 1** only considers the hydrogen production facility and hydrogen compression.
- **Gateway 2** includes the hydrogen production facility, compression, and the CO_2 T&S infrastructure.

Gateway 1 hydrogen production costs for all HEE and POX cases (other than Gabon[264]) are lower cost than the incumbent SMR counterfactual without CCS in the Netherlands. This results in a negative cost of CO_2 abatement when the carbon price is applied. The cost of CO_2 abatement at gateway 2 is greater than at gateway 1 for both SNR and POX technologies. HEE does not require CCS and costs are the same at gateway 1 and 2. High cost of CO_2 abatement at Gateway 1 is seen where production costs are high (e.g., SNR in the Netherlands), whilst high cost of CO_2 abatement at Gateway 2 is seen for all regions where CO_2 T&S over large distances is required (e.g., Brazil and Angola).

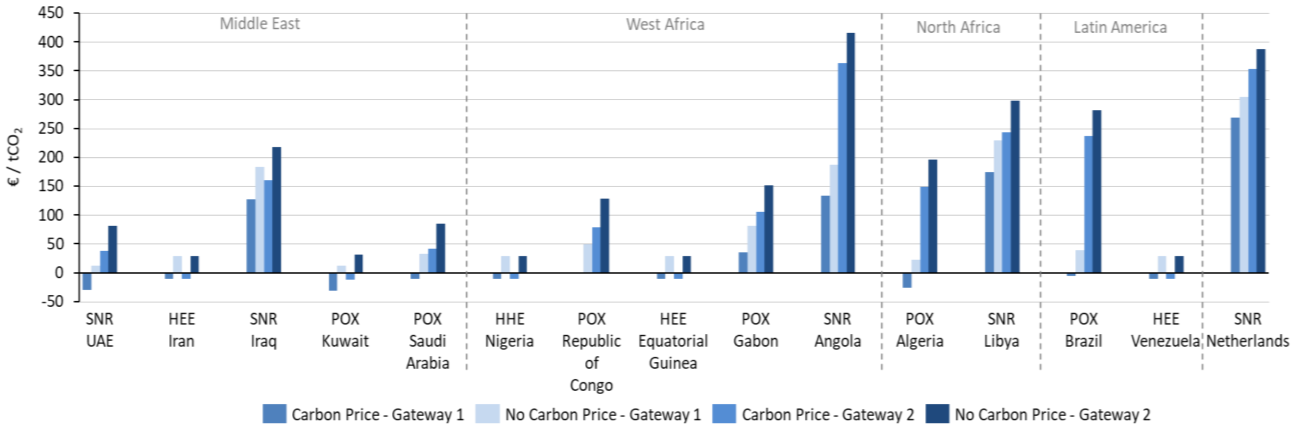

Figure 100: Cost of CO_2 Abatement Emissions in 2020 for an operational lifetime of 25 years (SNR and POX TRL 9, HEE TRL 4-6) – (€ / tCO_2)[265]

8.1.4 Regional Opportunities

POX and SNR are established hydrogen production technologies, whereas HEE is yet to be demonstrated at scale. POX was analysed in six countries, whereas SNR and HEE were explored in five and four countries respectively, as justified in Section 4.4.

- SNR relies on light oil-based feedstock such as naphtha and therefore is suitable for regions with refining capabilities that can ensure a reliable stream of feedstock. Both the Netherlands and the UAE

[264] Gabon has higher electricity prices.
[265] The HEE scenario assumes a hydrogen turbine and that the well cost is included.

are countries with advanced refining capabilities, whereas there is significant refining capacity in Angola, Libya and Iraq. As a result, SNR was selected for analysis in these regions.

- Unlike SNR, POX can accept a wide range of feedstocks, from natural gas up to vacuum residue. This report focused on using vacuum residue. As for SNR, this is a product available where crude oil is refined via vacuum distillation. As a result, POX was chosen for analysis in Kuwait, Saudi Arabia, Republic of Congo, Gabon, Algeria and Brazil.
- HEE is the only proposed oil-based hydrogen production technology that does not produce any scope one emissions as part of the process. Many regions analysed in this study are yet to develop plans for any large-scale CCS projects and geological storage sites in the region are yet to be validated and appraised. HEE was therefore selected for analysis in Iran, Nigeria, Equatorial Guinea and Venezuela.

Although detailed analysis was performed for a single oil-based hydrogen production technology in each country, some regions may be suited to multiple oil-based hydrogen production technologies. Findings from this study suggest that the following oil-based hydrogen production technologies could be deployed in the regions outlined below:

Middle East

- POX and SNR technologies would be suited for this region as low-cost feedstock from refineries is likely to be widely available. CO_2 T&S infrastructure could be utilised by both SNR and POX technologies.
- HEE also has significant potential in the region as depleted onshore fields could be utilised for blue hydrogen production. Co-production of oil and hydrogen is a significant benefit that can be utilised in the transition to a hydrogen economy.

West Africa

- Nigeria and other countries in West Africa are increasing their refining capacity with the Dangote refinery set to be the largest in Africa and operational later this year.
- Feedstock for SNR and POX processes is likely to be widely available, however, a lack of incentives to develop CCS infrastructure in the region is likely to act as a barrier for these production technologies being deployed.
- HEE is likely to remain the favoured method for oil-based blue hydrogen production in the region. Offshore opportunities should be explored to limit damage from local vandalism of infrastructure.

North Africa

- Algeria and Libya benefit from multiple refineries along the North African coastline that could provide a reliable source of feedstock for the SNR and POX processes. CO_2 T&S infrastructure would require developing for both POX and SNR processes.
- HEE could provide an attractive solution for utilising depleted oil fields for hydrogen production in the region without requiring CCS infrastructure development. However, long-range distribution to the country's ports in the North would be required.

Latin America

- There are seventeen refineries located throughout Brazil that produced almost 3 million tonnes of Naphtha in 2018[266]. Venezuela also has significant refining capacity; however, this has been operating at low-utilisation rates for many years. SNR based hydrogen production would be feasible if naphtha is available at low-cost. CO_2 T&S infrastructure requires development for both SNR and POX technologies; however, learnings can be applied from commercial CCS operation in the Santos basin.
- HEE could be a feasible production technology if hydrogen production can successfully be demonstrated at large scale offshore in Brazil (as this is where the countries primary oil reserves are located). However, low-value oil reserves onshore that are uneconomical for oil recovery could provide an attractive option for hydrogen production, particularly in Venezuela where billions of barrels of extra heavy crude oil and bitumen deposits are located in the Orinoco belt. CO_2 T&S are predicted to be the

[266] Tilasto 2019, Brazil: Naphtha, total production (thousand metric tons)

largest cost component in 2050 for the POX process; HEE could become an attractive alternative that does not require the development of CCS infrastructure.

North Sea

- POX technology would be suited for this region as low-cost feedstock from refineries in the Rotterdam industrial cluster is likely to be widely available. CO_2 T&S infrastructure developed in the cluster could be utilised by both SNR and POX technologies.
- HEE could be a feasible production technology if hydrogen production can successfully be demonstrated at large scale offshore. Depleted offshore oil fields are likely to be available at low cost as countries in the North Sea region are primarily focused on the extraction of natural gas. However, deploying HEE offshore is likely to significantly increase the cost of hydrogen distribution unless legacy assets can be utilised.

8.1.5 Conclusions

For all regions, availability of low-cost feedstock is vital for reducing the LCOH.

- Accessing low-value and waste oil-based products e.g.. residuum, is critical for reducing the cost of POX based hydrogen production.
- HEE has a significantly lower LCOH where depleted oil fields are utilised as these are assumed to have no cost. It is likely that these will be available in large numbers at low to zero cost with owners of depleted fields looking to minimise liability and decommissioning costs. However, there should remain opportunities for co-production to aid a transition.
- The SNR process is limited in the cost reductions that can be achieved for the feedstock cost component. Feedstock such as Naphtha and LPG are refined oil products that intrinsically have a higher value due to the refining processes required to produce them. Feedstock cost reductions should be minimised wherever possible to reduce the overall LCOH, however, this will be a future barrier for the technology deployment when compared to POX and HEE processes.

For all processes, locating the hydrogen production technology in close proximity to the point of demand will reduce hydrogen distribution costs.

- Industry is predicted to provide the vast majority of demand in the **short to mid-term** as shown for all regions in Section 3 therefore locating hydrogen production facilities nearby to large scale industry will allow economies of scale to be maximised.
- **Beyond 2030**, demand from other sectors such as transport, heat and power may result in dedicated hydrogen production facilities being increasingly economical to develop in non-industrial areas. For example, transport is predicted to provide 75.8 Mtoe and 42.7 Mtoe of hydrogen demand in Europe and the Middle East, respectively. Dedicated oil-based hydrogen production facilities could therefore be deployed in regions surrounding cities where demand for fuel cell powered vehicles and power generation is expected to be high.

The analysed regions could be classified as net hydrogen importers and exporters, based on the local hydrogen demand and potential for hydrogen production.

- The North Sea region will look to supply hydrogen to local industry in the short term with future potential for blending hydrogen into the gas grid and supplying transport and power demands.
- All other study regions will aim to maximise hydrogen export opportunities in the short term with Western Europe, USA and East Asia identified as the first regions predicted to uptake hydrogen fuelled technologies at scale.
    - Hydrogen production in West Africa, North Africa and Latin America is expected to target markets in Western Europe and the USA as local demand is expected to be minimal in comparison to these developing markets.
    - Hydrogen production in the Middle East is expected to initially target developing markets in East Asia such as South Korea and Japan; both countries are likely to rely heavily on hydrogen

imports due to limited potential for domestic production. Whilst, in this analysis, Rotterdam Port (Netherlands) is the same distance as the Pyeongtaek-Dangjin Port (South Korea), the Middle East may struggle to compete due to more favourable exporting countries, as described above.

- However, decarbonisation ambitions in the Middle East (particularly in the UAE, Saudi Arabia and Kuwait) are predicted to increase significantly over the next 30 years, that could potentially be achieved through an increased uptake of hydrogen-based technology in the region.

8.2 Market Competitiveness

8.2.1 Policy

The regional policy could dictate the type of hydrogen production that would be most desired in each region.

- **Hydrogen policy in Europe is focussed on developing green hydrogen production capacity** with the EU Commission's report "A Hydrogen Strategy for Climate Neutral Europe" setting a minimum target of 40GW of electrolysers to be installed by 2030[267]. Although developing renewable hydrogen production in Europe is the priority, the EU Commission recognises the need for forms of low carbon hydrogen production that will support the future uptake of renewable hydrogen. Whilst yet to be defined, this is expected to include hydrogen with a sufficiently low carbon intensity. This could apply to oil-based hydrogen, which would bring additional advantages such as scale of production.
- **Hydrogen policy in the USA does not directly support a particular hydrogen production method.** However, incentives such as the 45Q tax credit could be utilised to increase the deployment of oil-based blue hydrogen production. The 45Q tax credit will encourage the development of CCS infrastructure where projects will eventually be able to receive US$50/t$CO_2$ for geological carbon storage[77]. Furthermore, the Low Carbon Fuel Standard in California is an example of a market incentive that has been successfully implemented to encourage the uptake of hydrogen fuelled vehicles. Credits are awarded when the carbon intensity of the fuel is below the benchmark carbon intensity curve (which has been developed to reduce over time)[78]. This would apply to oil-derived hydrogen for transport provided that the carbon intensity of the fuel was below the benchmark. This was set at 91.98 gCO_2e/MJ and 92.92 gCO_2e/MJ in 2020 for gasoline and diesel fuel substitutes respectively[78]. The USA is expanding the low Carbon Fuel Standard incentive more widely, supporting uptake.
- **Hydrogen policy in East Asia varies by country however, the region has not discounted any form of hydrogen production method.**
  - South Korea has one of the most developed strategies in the region for increasing the uptake of hydrogen fuelled technologies. However, little detail is provided on how the production of hydrogen will be decarbonised. The South Korean government aims to have 70% of the country's hydrogen demand met from low carbon production sources by 2040. This is likely to include a mix of both blue and green hydrogen production methods, however, grey hydrogen will likely make up the remainder of the countries demand still representing a significant proportion of overall demand[86].
  - Japan is looking to increase hydrogen production capacity over the next 30 years. However, the country is likely to rely on hydrogen imports to meet levels of demand. Due to a lack of renewable generating capacity, blue hydrogen production utilising fossil fuel sources (including oil-based production) with CCS is likely to form a significant portion of both domestic production and international imports[88].

[267] European Commission 2020, A hydrogen strategy for a climate-neutral Europe

8.2.2 Current Market

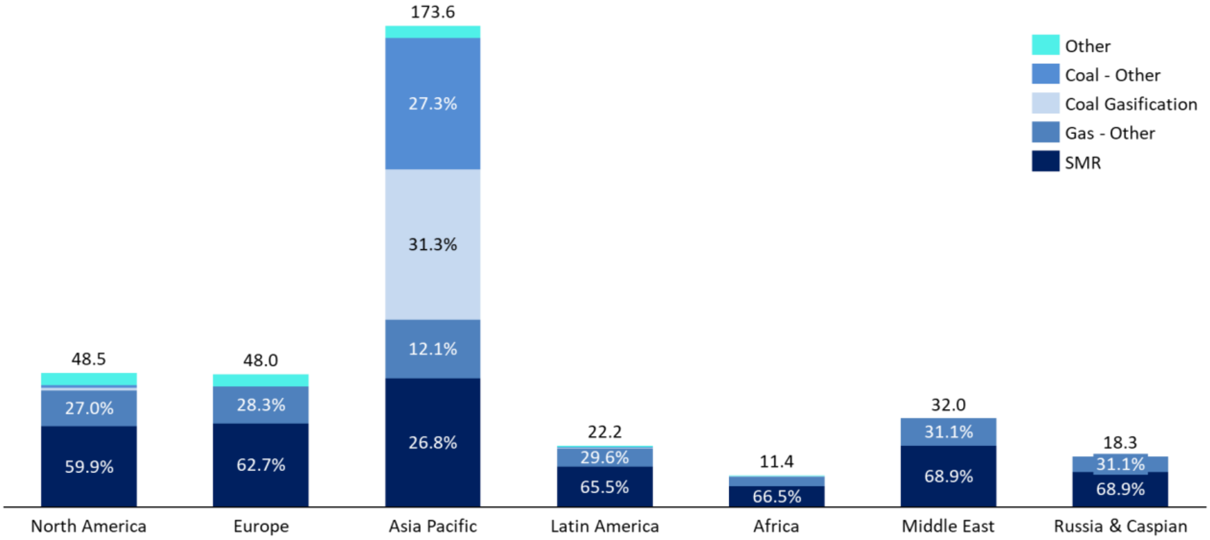

Figure 101: Current hydrogen supply by region and production type (Mtoe/year)[268]

Oil-based hydrogen production technologies will have to compete with established fossil fuel production as well as developing green production from renewable sources. Currently, SMR without CCS is the dominant production technology in the majority of regions, with coal-based hydrogen production prevalent in certain countries in Asia e.g., China, as shown in Figure 101.

Natural gas-based blue hydrogen production in the Netherlands is shown to be more expensive than the benchmark for the four different technologies in Figure 102. Here, the costs vary between 9-32%; this is significantly more competitive than SNR in the Netherlands which is 118% more expensive than the reference case. **The current cost of naphtha feedstock in comparison to natural gas in the Netherlands is the most significant cost component causing blue hydrogen production from SNR to be considerably more expensive than blue hydrogen production from SMR.**

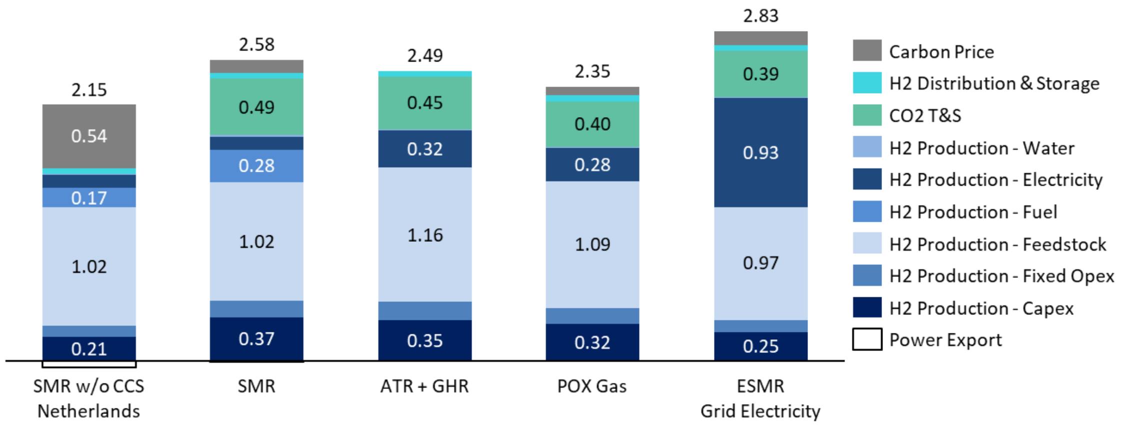

Figure 102: Comparison of natural gas-based hydrogen production with CCS in the Netherlands in 2020 (€/kgH_2)[269]

Natural gas feedstock costs remain as the largest cost component for natural gas-based blue hydrogen production technologies in the Netherlands in 2050 as shown by Figure 103. The 'lowest case' for POX and HEE oil-based hydrogen production processes can utilise waste or low-value feedstocks, making the economics of oil-based hydrogen production significantly more attractive. This is shown for POX utilising waste

[268] Blue Hydrogen Roadmap, Element Energy (2021)
[269] Blue Hydrogen Roadmap, Element Energy (2021)

feedstock in the Netherlands where the LCOH is 42% lower than POX blue hydrogen production using the lowest cost natural gas option.

However, if the price of oil-based feedstock were to match the predicted cost of crude oil in 2050 (modelled as €38.7/MWh), POX oil is shown to be 17% more expensive than POX gas, demonstrating the sensitivity of the LCOH to feedstock price.

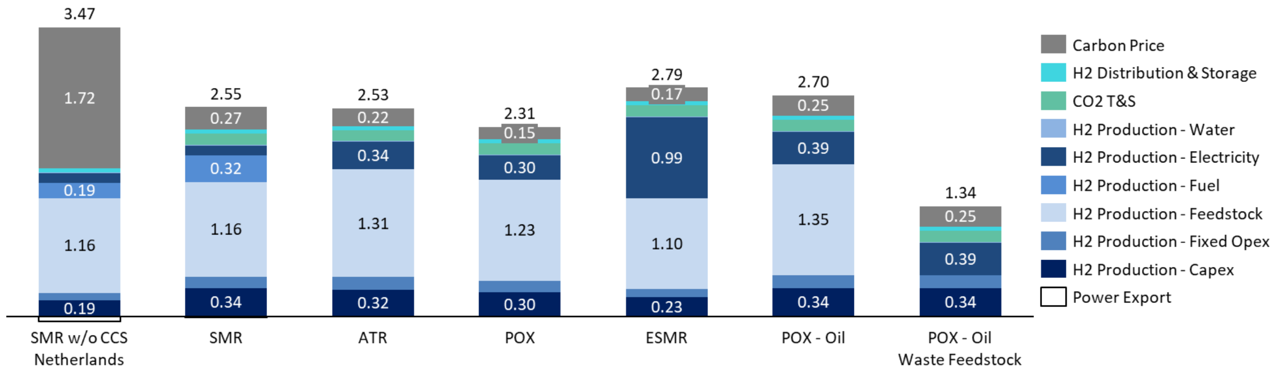

Figure 103: Comparison of natural gas-based hydrogen production, with CCS and oil-based POX hydrogen production in the Netherlands in 2050 (€/kgH_2)[270]

Blue hydrogen production is predicted to remain cheaper than green hydrogen production in the near term, as shown in Europe in 2030 in Figure 104. However, the cost of renewable hydrogen production will vary significantly by region and in some cases may be cheaper than blue hydrogen production. For example, electrolysis from renewables is approximately €2.48/kgH_2 in 2030, which would be significantly cheaper than SNR based hydrogen production in the Netherlands, whilst being higher cost than POX utilising waste feedstock. The LCOH from renewable electrolysis can also be sensitive to CAPEX costs, particularly when operating at reduced full load hours[4]. In regions with high potential for renewables capacity, combined with predicted high hydrogen demand, green hydrogen production may make up a significant portion of market share. However, in some Asian countries such as Japan and South Korea where green production is predicted to be limited, blue hydrogen production from fossil fuels is expected to form most of the domestic low carbon production where sufficient CO_2 storage or access to CO_2 shipping is available, otherwise imports may be required.

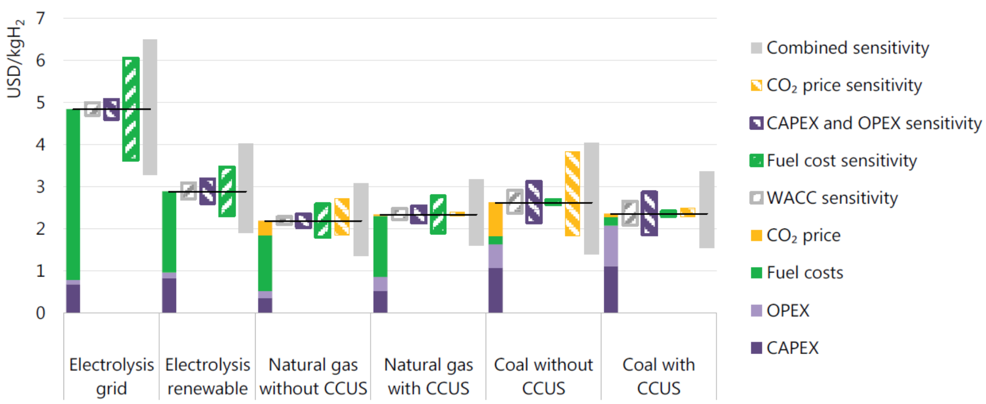

Figure 104: Hydrogen production costs for different technology options in Europe in 2030[4]

8.2.3 Export Opportunities

Oil-based hydrogen production technologies will have to compete with both natural gas-based blue hydrogen production and green hydrogen production from renewable sources when exporting to developed markets. Predicted costs of green hydrogen exported to Belgium provided by the 'Hydrogen Import Coalition'[271] are

[270] Carbon intensity of vacuum residue in Netherlands assumed to be 31gCO_2/kWh, an average of the value for Algeria and Brazil
[271] Hydrogen Import Coalition 2021, Shipping sun and wind to Belgium is key in climate neutral economy

compared against both green and blue hydrogen export costs from the IEA's "The Future of Hydrogen"[4] and analysis of oil-based production types performed in this study, where the bars show the range of costs. This is displayed for Middle East exports to Asia and Western Europe in Figure 105; exports from North Africa, Latin America and the Middle East to Western Europe are displayed in Figure 106.

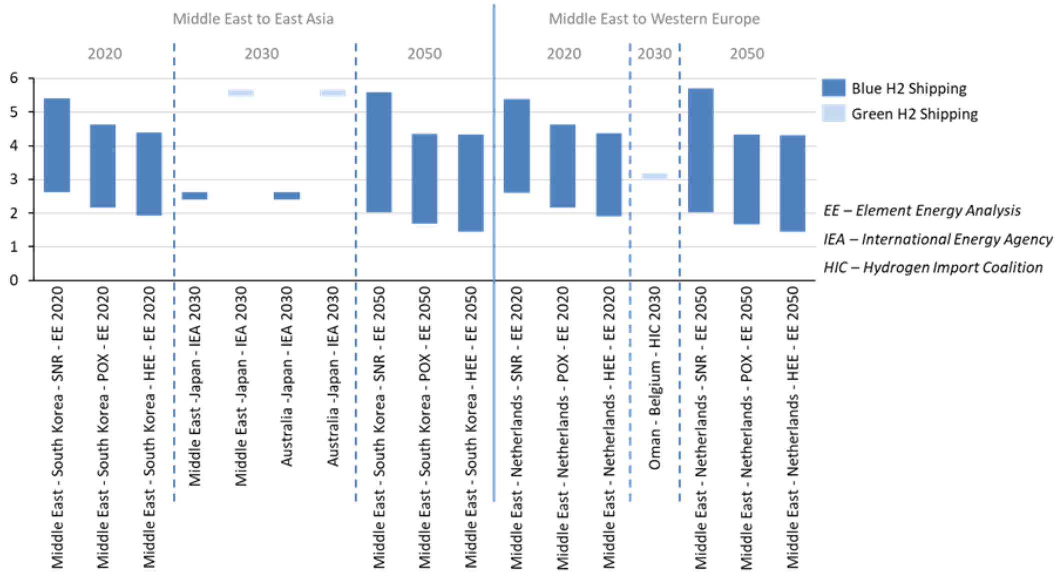

Figure 105: Comparison of hydrogen export costs in the Middle East by type to Asia (left) and Western Europe (right) - (€/kgH_2)[4, 271]

This analysis shows that in the short term, blue hydrogen from oil-based feedstocks produced in the Middle East and exported to East Asia and Western Europe is likely to be lower cost than from green production. However, natural gas based blue hydrogen production is likely to remain a cheaper alternative to SNR based production between 2020 and 2050. The significant range in export costs for all three blue hydrogen technologies is a result of the varying feedstock costs in each country. For SNR, the UAE is likely to be able to access low-cost naphtha feedstock whereas POX and HEE could utilise low-value or waste feedstocks. Blue hydrogen export from the Middle East to Western Europe may be competitive in the short term; however, beyond 2030 green hydrogen production export is predicted to significantly reduce in cost.

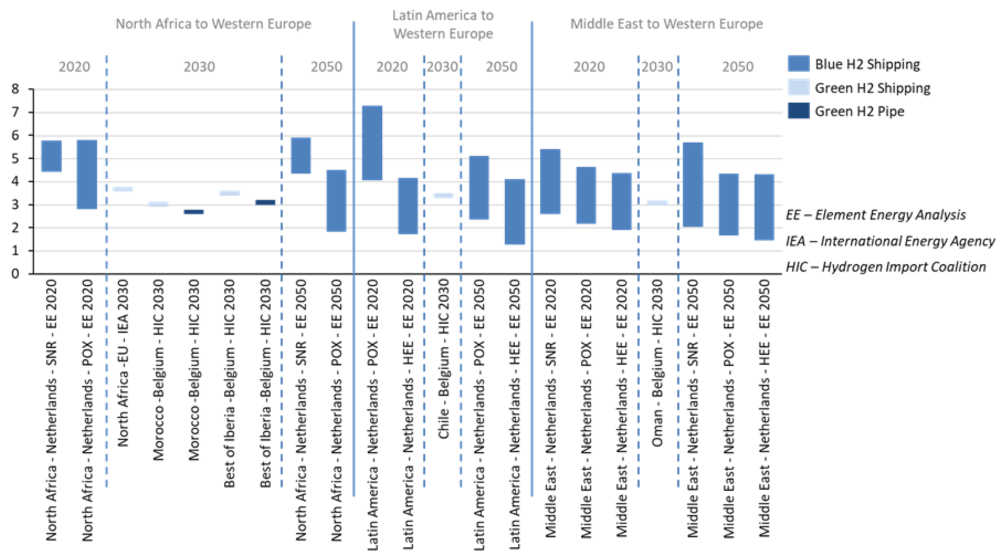

Figure 106: Comparison of hydrogen export costs to European countries by region and production type - (€/kgH_2)[4, 271]

Blue hydrogen exports from North Africa to Western Europe are not predicted to be cost competitive in 2020 or 2050 for SNR based technologies. However, POX hydrogen production technology has the potential to be cost competitive in both short- and long-term scenarios at the lower bound of the cost estimate; this assumes that waste or low-value feedstocks would be utilised.

POX based blue hydrogen exports from Latin America to Western Europe are unlikely to be cost competitive in the short term with Green hydrogen exports. However, POX hydrogen production has the potential to be cost competitive in the long-term scenario at the lower bound of the cost estimate; this assumes that waste or low-value feedstocks would be utilised. HEE exports from Latin America are predicted to be cost competitive in both short and long-term scenarios. Where depleted oil fields can be accessed at zero or low cost, HEE has the potential to be lower cost than green hydrogen exports.

In all cases, upper-bound scenarios (where feedstock costs are significant) are likely to result in the technology being uncompetitive with green hydrogen production methods.

This shows that the business model and production configuration for hydrogen derived from oil and oil-derived products is vital. These production modes are competitive where the feedstock price is minimised and, although not shown here, existing infrastructure from the oil and gas sector is used to minimise hydrogen distribution and CO_2 T&S costs as highlighted in Sections 4.2 and 4.3 respectively. HEE is also not shown here which, from previous analysis in this study, would also be competitive.

8.3 Conclusions and Recommendations

8.3.1 Competitivity

This study has shown that there is a pathway to competitivity for hydrogen derived from oil and oil-based products when compared to the other mainstream alternatives such as hydrogen derived from natural gas and electrolytic hydrogen. A comparison with gas-derived hydrogen is shown in Figure 107 for 2020 and Figure 108 for 2050.

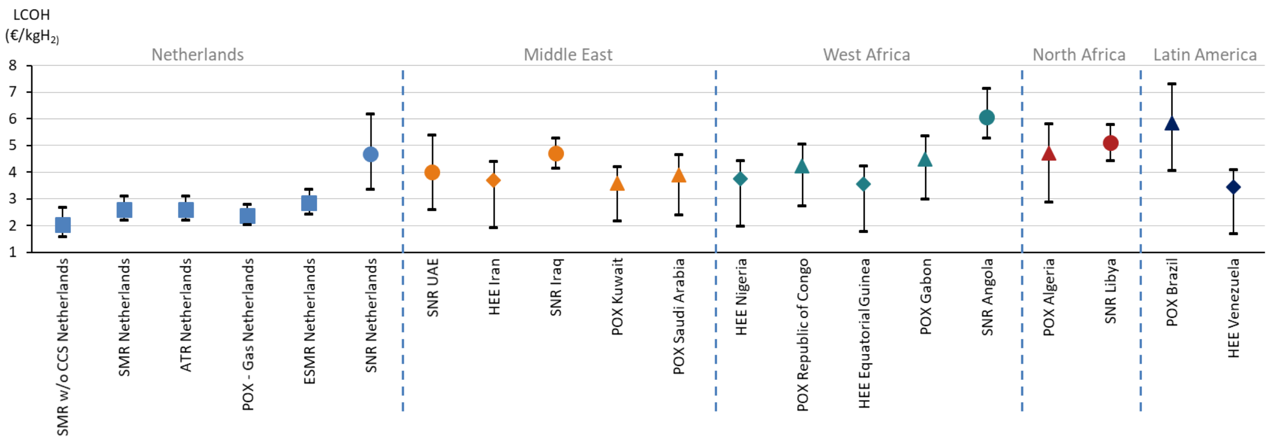

Figure 107: Range of costs for gas-derived hydrogen and oil-derived hydrogen. Range of costs is taken from the minimum and maximum cost scenarios for each technology in 2020, accounting for the uncertainties demonstrated in Section 5.1. Note that the final LCOH is based on delivery to the nearest major hydrogen demand region.

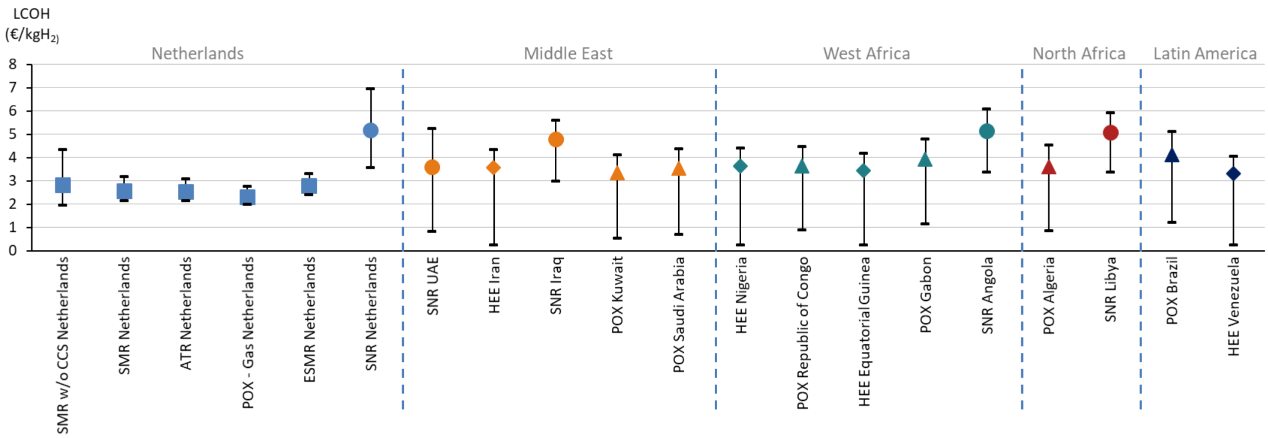

Figure 108: Range of costs for gas-derived hydrogen and oil-derived hydrogen. Range of costs is taken from the minimum and maximum cost scenarios for each technology in 2050, accounting for the uncertainties demonstrated in Section 5.1. Note that the maximum LCOH in each case is based on the primary hydrogen market shipped to in 2020 whilst the lowest LCOH is based on local hydrogen markets.

The wide range of costs shown here is largely due to the variety of markets which the oil-based blue hydrogen is assumed to supply. In the parallel gas study, the end use market is only considered to be local industry in the Netherlands (Rotterdam port). In this study, hydrogen is shipped and piped all over the world to high demand markets (Europe, North America and Asia) in 2020 and also serving local markets in 2050. This highlights the large cross-section of markets within which the oil-based technology could be competitive and the importance of low-cost distribution costs.

However, there remain concerns about the maturity of these technologies as they are even less widespread than equivalent gas-production options. Competitiveness could be achieved by either valuing the feedstock as a waste product (vacuum residue) or assuming it has no inherent economic value (oil from a retired oil well). Furthermore, the oil producing regions are a considerable distance from the primary hydrogen markets expected over the next decade, exposing the producing technologies to high costs of hydrogen distribution.

This section discusses the criteria for competitivity of the technologies:

- **Steam Naphtha Reforming** – As for POX, SNR also has a flexible deployment potential as it can be sited in close proximity to any refinery which supplies naphtha. However, this study raised concerns about the potential for SNR due to its high feedstock cost (e.g., SNR is 118% more expensive than SMR in the Netherlands). This technology should only be considered where the price of naphtha is less than that of natural gas, in which case it is competitive with gas-derived blue hydrogen.
- **Partial Oxidation** – This technology has flexible deployment potential as it can be sited in close proximity to any refinery where there is a supply of vacuum residue. In addition, the technology has the advantage of being flexible and could use other feedstocks beyond vacuum residue. Finally, this technology shows promise where it can use a feedstock which is considered a waste product; this significantly improves the economics.
- **Hygenic Earth Energy** – Questions remain over the long-term potential of HEE due to its relatively low TRL. However, Proton Technologies is ramping up its demonstration projects which should quickly prove if the technology is viable[272]. If the technology is proven, the technology should have potential for both co-production of oil and hydrogen in existing wells and dedicated hydrogen production from exhausted wells. Offshore opportunities should also be considered, particularly in those areas which are exposed to vandalism of onshore equipment. In addition, HEE technology could make the production of hydrogen competitive in other regions for which SNR / POX would be too expensive.

Even where these technologies cannot compete on a direct LCOH basis, there remain opportunities. Many regions in Western Europe and Asia Pacific are expected to rely on large-scale imports of low carbon hydrogen

[272] H_2 View 2021, Proton demonstration site to produce 1,000 tonnes of hydrogen per day

which could include hydrogen derived from oil and oil-based products. The scale of supply via oil-derived hydrogen could offset the higher cost and facilitate the developments of these hydrogen economies in the near-term.

8.3.2 Recommendations

Based on this analysis, key recommendations include:

- **Identifying scenarios where the value of the feedstock can be minimised.** This includes waste products, for POX, and oil with no economic value due to exhausted wells, for HEE. This will also demonstrate the technical ability of these technologies to process a range of feedstocks, increasing their utility in different scenarios.
- **Exploring local hydrogen demand scenarios and reducing costs in the value chain for lower cost hydrogen distribution**, as discussed in Section 7. This includes leveraging learnings and investments from ongoing projects such as Acorn which are demonstrating ways to reuse existing infrastructure for CO_2 T&S.
- **Including blue hydrogen production technologies in CCS cluster plans** to take advantage of scales of deployment. This will reduce CO_2 T&S costs.
- Where favourable for the technology, supporting aggressive carbon pricing to outcompete conventional production of “grey” and “brown” hydrogen production technologies.
- **Further work is needed to explore optimal technology type by region.** This study explored five different case studies with one technology deployed by country. As discussed in Section 8.1.4, these technologies are not limited to locations and so blue hydrogen producers should conduct further feasibility studies to optimise deployment choices.
- **Encourage private and public cooperation in deployment of these technologies**, particularly where local governments are unable to provide direct financial support due to resource limitations. This will ensure that the development and deployment of these technologies accelerates.
- **Additional technology development, including demonstration projects, to prove the technologies in the field and raise awareness.** This includes resolving data gaps, as discussed in Sections 6.5 and 9.2. This will ensure that these technologies are understood and included in national and international hydrogen strategies, facilitating international collaboration. This is particularly critical for technologies like HEE which need to advance their TRLs.
- Governments should support blue hydrogen technologies with sufficiently low carbon footprints as calculated from life cycle assessments. This includes sufficient high carbon capture rates (preferably >90%), use of electricity with low carbon content, and in case natural gas is used for heat and/or feedstock a strong focus on reduction of methane leakages involved with production and transportation.

8.3.3 Timescales for Action

The timeline for the implementation of these technologies is expected to vary by technology.

Steam Naphtha Reforming and Partial Oxidation

- In the short-to-medium term, both SNR and POX have high TRLs and are therefore expected to be deployed where a) the above criteria for both technologies are met and b) there is wider consensus and activity in industrial clusters to develop CCS infrastructure. This is an inherent requirement for this technology, and it is uneconomic for standalone infrastructure to only be developed for blue hydrogen production. This will therefore follow the deployment of CCS clusters.
- In the long-term, the use of both POX and SNR become dependent on the availability of feedstocks. Where refining capacity is reduced, there may be a reduction in the supply of naphtha and heavy feedstocks for hydrogen production. This may limit the further uptake of this technology.

Hygenic Earth Energy

- In the short-to-medium term deployment of HEE is dependent on the success of ongoing and planned demonstration projects. Stakeholders should support the demonstration of this technology, giving it more opportunities to accelerate its development by also testing it in a variety of regions, including offshore. Once mature, there should be coordination with oil and gas companies to deploy the technologies on those fields where there is potential for co-production and, equally, those fields which are coming to the end of life. In this latter case, there can be economic savings by ensuring that existing infrastructure is reused for the purposes of hydrogen production, avoiding equipment abandonment and decommissioning costs.
- Longer-term, the uptake of hydrogen derived from HEE will remain unexposed to any changes in the use of oil as the technology can continue to use retired oil and gas wells.

Low TRL Technologies

- This study also explored other production technologies such as plasma reformation, pyrolysis and HyRes. Stakeholders should continue to support the advancement of these technologies, which would come to fruition over longer timescales,

Beyond the production technologies, it is also important to scale the supply of hydrogen with hydrogen demand. As shown in Section 3, those regions with developed hydrogen strategies are expected to see reasonable increases in demand out to 2030 before significant increases in demand from transport and industrial fuel switching creates an exponential rise. Memorandums of Understanding and international trade agreements are therefore important over this period to ensure that oil-derived hydrogen is a feature in these discussions and is considered for bulk scale use in these regions.

9 Appendices

9.1 Global Hydrogen Demand

The hydrogen demand forecast uses two different approaches to estimate the future demand based on the maturity of hydrogen activity in study regions. This is discussed in Section 3. This section provides a breakdown of these assumptions by region.

Note that the 2040 data that is included in this breakdown is based on linear interpolation between 2030 and 2050. This is due to the high degrees of uncertainty associated with this period. This arises from data gaps in literature. Therefore, the data is intended to act as a guide to the reader on hydrogen uptake in this period.

9.1.1 Developed Hydrogen Strategy Regions

North America

The hydrogen demand forecast in the USA case study and the North America regional analysis is based on the IEA's "Future of Hydrogen"[4] report, FCHEA's "Roadmap to a US Hydrogen Economy"[70] and the Government of Canada's "Hydrogen Strategy for Canada"[71].

The Roadmap to a US Hydrogen Economy was a key source in this analysis. The US hydrogen road map was developed by the Fuel Cell and Hydrogen Energy Association (FCHEA) with input from industry experts across a broad range of sectors with the aim of increasing the adoption of hydrogen across the US economy. The report outlines how hydrogen can be adopted and form a critical part of a low carbon energy mix in the US over the next thirty years. The report recognises that there is significant variation throughout the country in terms of national and state policies, infrastructure needs and community interest. In the future, it is likely that each state or region will have its own roadmap and specific policies for the development of hydrogen infrastructure. California is identified as a region where there is strong support for the adoption of hydrogen technology, particularly for the uptake of FCEVs in the transportation sector.

Industry

- Industrial hydrogen demand is broken into refining, ammonia, methanol, and other industry.
- For all demand points, the forecast is taken as an average of literature from the IEA's and FCHEA's hydrogen demand forecasts in industry.
- The FCHEA is only for the USA. Therefore, the results are inflated to give total demand in US & Canada. This inflation factor is based on the US industrial energy demand as a fraction of total US & Canada industrial energy demand, as defined in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020".
- Fraction of total energy demand is based on the energy demand forecast for the industrial sector from the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020".

Table 19: North America industrial hydrogen demand

Year	Units	2020	2030	2040	2050
Refining	Mtoe	29.1	31.4	32.8	34.1
Ammonia	Mtoe	11.9	15.4	17.4	19.3
Methanol	Mtoe	4.8	5.2	6.1	6.9
Other Industry	Mtoe	2.6	3.2	16.8	30.4
Total	Mtoe	48.5	55.3	73.1	90.8
Fraction of Total Energy Demand	%	13.3	14.6	18.7	22.5

Transport

- Transportation hydrogen demand is broken into rail, LDVs, HDVs, NRMM and synthetic fuels.
- Demand trajectories for all technologies except rail is based on the FCHEA forecasts.

- Data points in 2020 are based on available literature on hydrogen consumption in transportation in California[273],[274]
- Demand for trains is based on assuming that one third of total demand for energy in the rail sector will be for hydrogen[275].
- The FCHEA is only for the USA. Therefore, the results are inflated to give total demand in US & Canada. This inflation factor is based on the US transportation energy demand as a fraction of total US & Canada transportation energy demand, as defined in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020".
- Fraction of total energy demand is based on the energy demand forecast for the transport sector from the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020".

Table 20: North America transport hydrogen demand

Year	Units	2020	2030	2040	2050
Rail	Mtoe	-	0.0	2.5	5.0
LDVs	Mtoe	0.0	2.6	17.5	32.4
HDVs	Mtoe	0.0	2.4	35.1	67.7
NRMM	Mtoe	0.0	0.2	0.9	1.5
Synthetic Fuels	Mtoe	-	-	23.9	47.0
Total	Mtoe	0.0	5.3	79.5	153.6
Fraction of Total Energy Demand	%	0.0	0.7	11.9	24.8

Heat

- Demand for hydrogen for heat is based on FCHEA's and the Canadian Government's forecasts. These results are summed to give regional demand.
- FCHEA provides fuel switching by fuel source for heat uptake in the USA. This uses fuel switching rates for oil and natural gas. These fuel switching rates are applied to the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for built environment.
- Fraction of total energy demand is based on the energy demand forecast for the built environment sector from the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020".

Table 21: North America heat hydrogen demand

Year	Units	2020	2030	2040	2050
Total	Mtoe	-	6.2	45.6	84.9
Fraction of Total Energy Demand	%	-	1.1	7.9	14.5

Power

- The demand trajectory is based on the FCHEA forecasts.
- The FCHEA is only for the USA. Therefore, the results are inflated to give total demand in North America. This inflation factor is based on the US power demand as a fraction of total North American power demand, as defined in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020".
- Fraction of total energy demand is based on the energy demand forecast for the power sector from the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020".

[273] Fuel Cell Works 2020, California: FCEV Sales, FCEB, & Hydrogen Station Data as of August 1, 2020
[274] US Department of Energy 2018, Fact of the Month November 2018: There Are Now More Than 20,000 Hydrogen Fuel Cell Forklifts in Use Across the United States
[275] Association of American Railroads 2013, Class 1 Railroad Statistics

Table 22: North America power hydrogen demand

Year	Units	2020	2030	2040	2050
Total	Mtoe	-	1.4	9.7	18.0
Fraction of Total Energy Demand	%	-	0.2	1.1	2.1

Europe

The strong level of information available for hydrogen forecasts in Europe provided from a range of sources. European forecasts, supported by the expansive resources available from the IEA, ensured that only a literature review was required to forecast hydrogen demand for this region. The Hydrogen Roadmap Europe was developed by the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), a public private partnership made up of the European Commission, industries represented by Hydrogen Europe and the Hydrogen Europe research community. The report was developed with input from seventeen leading European industrial actors and outlines a pathway for hydrogen and fuel cell deployment in Europe until 2050. The report was published in February 2019 and formed a key source in this analysis. The overall hydrogen forecast for Europe was developed utilising data from: "*Hydrogen Roadmap Europe*" – FCHJU[72], "*Hydrogen Use in EU Decarbonisation Scenarios*" - European Commission, "*Energy Outlook*" – BP[236]. This is supplemented by data from "Future of Hydrogen" – IEA and "*WEO 2020*" – IEA[4].

Industry

- Industrial hydrogen demand is broken into refining, ammonia, methanol, and other industry.
- Growth in refinery, methanol and ammonia demand is largely driven by forecasts from the "Hydrogen Roadmap Europe"[72] and "IEA Future of Hydrogen"[4] to determine the hydrogen demand.
- Where there were gaps by end use case, the trends in global development of end use markets were modelled and applied to overall European demand.

Table 23: European industrial hydrogen demand

Year	Units	2020	2030	2040	2050
Refining	Mtoe	24.7	25.4	26.0	26.6
Ammonia	Mtoe	12.2	14.4	15.4	16.3
Methanol	Mtoe	1.8	2.9	3.2	3.5
Other Industry	Mtoe	9.2	15.4	28.3	41.1
Total	Mtoe	47.9	58.1	72.8	87.4
Fraction of Total Energy Demand	%	14.2	17.3	21.5	25.7

Transport

- Transportation hydrogen demand is broken into rail, LDVs and HDVs.
- There are high degrees of uncertainty about the potential for demand from passenger cars due to advances in the battery electric vehicle sector in Europe.
- Instead, the focus is on heavier duty markets such as buses, trucks, trains and synthetic fuels for aviation and maritime purposes.
- Growth in hydrogen fuelled transport is largely driven by forecasts from the "Hydrogen Roadmap Europe"[72] and "IEA Future of Hydrogen"[4] to determine the hydrogen demand.

Table 24: European transportation hydrogen demand

Year	Units	2020	2030	2040	2050
Rail	Mtoe	0.01	0.4	3.8	7.2
LDVs	Mtoe	0.00	2.9	23.4	43.9
HDVs	Mtoe	0.00	0.5	12.6	24.7
Total	Mtoe	0.01	3.7	39.8	75.8
Fraction of Total Energy Demand	%	0.0	1.0	12.6	27.8

Heat

- Hydrogen demand for heat is expected to vary significantly by country within Europe. This is because some forecasts focus on dedicated hydrogen networks, some consider hydrogen blending up to 20% and others focus on electrification.
- Central forecasts from literature on the demand for hydrogen from heat from the following sources have been utilised:
    - IEA – Future of Hydrogen[4]
    - Hydrogen Roadmap Europe[72]
    - BP – Net Zero Strategy[236]
    - EU Commission – Hydrogen use in EU decarbonisation scenarios[276]

Table 25: European heat hydrogen demand

Year	Units	2020	2030	2040	2050
Total	Mtoe	-	8.4	23.5	38.5
Fraction of Total Energy Demand	%	-	1.7	4.9	8.3

Power

- Hydrogen demand for power is not predicted to form a major part of total hydrogen demand in Europe.
- Central forecasts from literature on the demand for hydrogen from power from the following sources have been utilised:
    - IEA – Future of Hydrogen[4]
    - Hydrogen Roadmap Europe[4]
    - BP – Energy Outlook[236]
    - EU Commission – Hydrogen use in EU decarbonisation scenarios

Table 26: European power hydrogen demand

Year	Units	2020	2030	2040	2050
Total	Mtoe	-	5.6	7.6	9.6
Fraction of Total Energy Demand	%	-	0.8	1.0	1.2

Asia Pacific

Hydrogen demand forecasts in the Asia Pacific region vary significantly by country. Countries such as South Korea, Japan and Australia are assessing the potential role of large-scale hydrogen uptake in meeting their net-zero goals. However, many countries within the Asia Pacific region are yet to publish any data on deployment of future hydrogen technology. A range of detailed hydrogen reports for individual countries were utilised with hydrogen demands applied to the regional level. These include:

Demand and Supply Potential of Hydrogen Energy in East Asia

This report was published in 2018 by the Economic Research Institute for ASEAN and East Asia. The report forecasts hydrogen demand for the region for transportation, industry, and power generation sectors in 2040. China and India are identified as the countries with the greatest demand, whilst significant demands are also predicted in Japan and South Korea.

Australian and Global Hydrogen Demand Growth Scenario Analysis

This report was published in November 2019 by Deloitte, The Council of Australian Governments (COAG) Energy Council and the Australian National Hydrogen Strategy Taskforce. The COAG Energy Council has a vision of developing Australia into a major player within the hydrogen industry by 2030. The report also outlines key policies and initiatives deployed by countries in the Asia Pacific region that encourage the uptake of hydrogen.

[276] European Commission 2020, hydrogen use in EU decarbonisation scenarios

Hydrogen Roadmap South Korea

The South Korean government has identified hydrogen as a new growth engine for the country and has pledged to develop a hydrogen economy. Currently, the government is focusing on developing a domestic hydrogen market. This report was published in November 2018 by the Study Task Force (with analytical support from Mckinsey & Company) consisting of senior executives from seventeen companies within the hydrogen industry.

Industry

- Industrial hydrogen demand is broken into refining, ammonia, methanol, and other industry.
- Growth in refinery, methanol and ammonia demand is largely driven by forecasts from the IEA's "The Future of Hydrogen".
- The demand for other industrial end use cases is based on country specific growth scaled to the regional level. The total energy demand for the region is consistent with other global perspectives on industrial demand from Asia Pacific over this timeframe.

Table 27: Asia Pacific industrial hydrogen demand

Year	Units	2020	2030	2040	2050
Refining	Mtoe	39.0	39.6	39.9	40.1
Ammonia	Mtoe	53.5	62.8	67.1	71.4
Methanol	Mtoe	23.3	36.9	40.9	44.8
Other Industry	Mtoe	53.6	67.4	131.2	195.0
Total	Mtoe	169.4	206.7	279.0	351.2
Fraction of Total Energy Demand	%	10.2	10.7	12.9	14.4

Transport

- Transportation hydrogen demand is broken into rail, LDVs, HDVs, NRMM and shipping.
- The demand for transport is expected to vary significantly by country within the Asia Pacific region.
- This analysis was based on a comparison of demand forecasts in China, Australia, South Korea and Japan. The demand from these regions was applied to the regional trends for hydrogen to forecast a breakdown by use type.
- Trends from the sources listed below were applied to the entirety of the Asia Pacific region to determine regional trends.
  - PWC – Embracing Clean Hydrogen for Australia[277]
  - Hydrogen Roadmap Korea[75]
  - Deloitte – Australia and Global hydrogen Demand Growth Scenario Analysis[74]
  - Demand and Supply Potential for Hydrogen Energy in East Asia[73]
  - South Korea's Hydrogen Strategy and Industrial Perspectives

Table 28: Asia Pacific transportation hydrogen demand

Year	Units	2020	2030	2040	2050
Rail	Mtoe	-	-	0.8	1.6
LDVs	Mtoe	0.01	14.2	69.7	125.2
HDVs	Mtoe	0.06	9.2	91.6	174.0
NRMM	Mtoe	0.00	0.3	4.9	9.5
Shipping	Mtoe	-	-	6.0	12.0
Total	Mtoe	0.1	23.7	173.0	322.2
Fraction of Total Energy Demand	%	0	2.4	15.4	25.8

[277] PWC 2019, Embracing clean hydrogen for Australia

Heat

- Hydrogen demand for heat is expected to vary significantly by country within the Asia Pacific region.
- This analysis was based on a comparison of demand forecasts in China, Australia, South Korea and Japan. The demand from these regions was applied to the regional trends for hydrogen.
- Trends from the sources listed below were applied to the entirety of the Asia Pacific region to determine regional trends.
    - PWC – Embracing Clean Hydrogen for Australia
    - Hydrogen Roadmap Korea
    - Deloitte – Australia and Global hydrogen Demand Growth Scenario Analysis[74]
    - South Korea's Hydrogen Strategy and Industrial Perspectives
    - Bloomberg – Hydrogen Economy Outlook[63]

Table 29: Asia Pacific heat hydrogen demand

Year	Units	2020	2030	2040	2050
Total	Mtoe	1.9	5.7	72.9	140.1
Fraction of Total Energy Demand	%	0.2	0.5	5.4	9.2

Power

- Hydrogen demand for power is expected to vary significantly by country within the Asia Pacific region.
- Trends from the sources listed below were applied to the entirety of the Asia Pacific region to determine regional trends.
    - Demand and Supply Potential for Hydrogen Energy in East Asia[73]
    - Hydrogen Roadmap Korea[75]
    - Deloitte – Australia and Global hydrogen Demand Growth Scenario Analysis[74]
    - South Korea's Hydrogen Strategy and Industrial Perspectives
    - Bloomberg – Hydrogen Economy Outlook[63]

Table 30: Asia Pacific power hydrogen demand

Year	Units	2020	2030	2040	2050
Total	Mtoe	2.2	41.7	92.5	143.2
Fraction of Total Energy Demand	%	0.1	1.4	2.4	3.3

9.1.2 Undeveloped Hydrogen Strategy Regions

For those regions where literature is not available, fuel switching rates are applied. The breakdown of energy by end use case and fuel type comes from the IEA's "World Energy Outlook 2020". Hydrogen forecasts, developed by Element Energy, use the "Stated Policies Scenario" to identify fuel switching opportunities from the status quo. Some hydrogen strategies are emerging, such as the report for the Gulf Cooperation Council[278].

Industry

- Industrial demand by region is broken down by use type: refining, methanol production, ammonia production and other.
- Refining forecasts use the IEA's "Future of Hydrogen" report, assuming that the regional distribution of refining activities remains constant and that the growth rate for the sector follows the "Current Trends" scenario.
- The demand for ammonia and methanol both use the same approach. The regional breakdown from the IEA's "Future of Hydrogen" for methanol and ammonia demand by region is assumed to be fixed. The global growth rate for both end use types is then applied to the regional demand.
- For other demand, the following methodology is used:

[278] Qamar Energy, 2020, Hydrogen in the GCC

- The fuel switching trajectories for the developed hydrogen strategy regions are calculated by dividing the forecasted hydrogen demand from other industrial activity by the industrial energy demand that comes from oil, natural gas, and coal in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for each region.
- These trajectories are averaged to give a single forecast for the developed hydrogen strategy regions.
- A ten-year delay is then applied to this forecast, to represent the slower uptake of hydrogen in those regions where the maturity of hydrogen activity is less developed.
- This fuel switching trajectory is then applied to the fossil fuel demand in the industrial energy demand forecasts from the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for each region.

Table 31: Emerging regions industrial hydrogen demand

Year	Units	2020	2030	2040	2050
Latin America	Mtoe	22.2	26.0	32.2	38.3
Africa	Mtoe	11.4	13.7	20.7	27.7
Middle East	Mtoe	32.0	38.4	51.1	63.7
Russia & Caspian	Mtoe	18.3	22.1	78.9	35.6
Total	Mtoe	84.0	100.1	132.7	165.3

Transport

- The uptake of hydrogen by different use cases by region is highly uncertain, even in those regions with a more developed hydrogen strategy.
- The fuel switching from fossil fuels to hydrogen, as calculated for those regions with more mature hydrogen strategies, is averaged to develop a fuel switching trajectory. This is done by dividing the forecasted hydrogen demand from other transportation activities by the transportation energy demand that comes from oil and natural gas in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for each region.
- This trajectory is then delayed by ten-years to represent the slower uptake of vehicles in these regions. This is used on demand for gas and oil in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for each region.

Table 32: Emerging region transportation hydrogen demand

Year	Units	2020	2030	2040	2050
Latin America	Mtoe	-	0.01	3.2	6.4
Africa	Mtoe	-	0.01	25.1	50.2
Middle East	Mtoe	-	0.01	21.4	42.7
Russia & Caspian	Mtoe	-	0.01	9.0	17.9
Total	Mtoe	-	0.04	73.6	147.1

Heat

- The uptake of hydrogen for heat by region is highly uncertain, even in those regions with a more developed hydrogen strategy.
- Fuel switching is only applied to natural gas, oil, and coal. These rates are based on the FCHEA's "Roadmap to a US Hydrogen Economy"[70] for oil and natural gas and estimates for coal based on wider literature. These are shown below for developed regions.
    - 2030: Coal (10%), natural gas (2%) and oil (8%)
    - 2050: Coal (40%), natural gas (31%) and oil (25%)
- This trajectory is then delayed by ten-years to represent the slower uptake of hydrogen for heat in these regions. This is used on demand for gas and, coal oil in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for each region.

Table 33: Emerging region heat hydrogen demand

Year	Units	2020	2030	2040	2050
Latin America	Mtoe	-	0.9	4.2	7.5
Africa	Mtoe	-	1.4	14.1	26.8
Middle East	Mtoe	-	4.6	17.6	30.5
Russia & Caspian	Mtoe	-	4.5	17.5	30.5
Total	Mtoe	-	11.3	48.9	86.5

Power

- The uptake of power by region is highly uncertain, even in those regions with a more developed hydrogen strategy.
- The fuel switching from fossil fuels to hydrogen, as calculated for those regions with more mature hydrogen strategies, is averaged to develop a fuel switching trajectory. This is done by dividing the forecasted hydrogen demand from other power activities by the power demand that comes from oil, coal, and natural gas in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for each region.
- This trajectory is then delayed by ten-years to represent the slower uptake of hydrogen in the power sector in these regions. This is used on demand for natural gas, coal, and oil in the IEA's "Stated Policies Scenario" in the "World Energy Outlook 2020" for each region.

Table 34: Emerging regions power hydrogen demand

Year	Units	2020	2030	2040	2050
Latin America	Mtoe	-	0.0	1.9	3.8
Africa	Mtoe	-	0.1	10.1	20.1
Middle East	Mtoe	-	0.1	5.1	10.0
Russia & Caspian	Mtoe	-	0.1	5.3	10.5
Total	Mtoe	-	0.3	22.4	44.4

9.2 Data and Assumptions used in TEA and LCA

All mass balances presented in this section are based on the schematic shown in Figure 109.

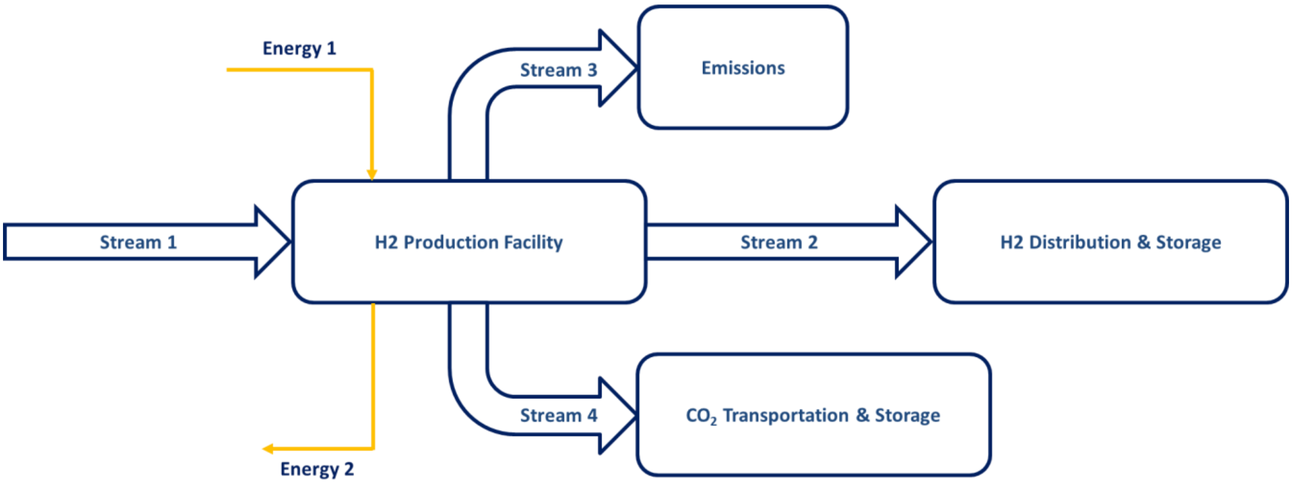

Figure 109: Mass and energy balance schematic for all production processes

In this section, assumptions used for the LCA, TEA, and both are differentiated by the headings.

It is important to note that the oxygen mass balance is included in the process data but not the mass balance. This is because, for all technologies which use oxygen, the oxygen is produced using an ASU. The oxygen supply is therefore captured by the energy supply to the entire system.

9.2.1 Steam Methane Reforming without CCS – Benchmark

Table 35: SMR without CCS Technology Process Data

Variable	Units	SMR w/o CCS[38]
Inputs		
Feedstock	kWh_{th}/kg	37.67
Fuel	kWh_{th}/kg	6.22
Raw Water	kg/kgH_2	6.64
Cooling Water	kg/kgH_2	381.92
Energy		
Process Power Requirement	kWh_e/kg	0.18
System Power Generation	kWh_e/kg	1.28
Compression Power Requirement	kWh_e/kg	1.10
Emissions		
CO_2	kg/kgH_2	-
Products		
Hydrogen	kg/kgH_2	1.00
CO_2 Export	kg/kgH_2	9.00
Process		
Purity of Hydrogen	%	99.90%
Hydrogen Export Pressure	bar	200.00
CO_2 Export Pressure	bar	110.00
CO_2 Capture Rate	%	0.00%

Table 36: SMR without CCS Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO_2 Emissions	4. CO_2 Export
Feedstock	GWh / yr	2,971	-	-	-
Fuel	GWh / yr	491	-	-	-
Water	ktonne / yr	524	-	-	-
CO_2	ktonne / yr	-	-	710	-
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	99.99	-	-
CO_2 Export Conditions					
Export Pressure	bar	-	-	-	N/A
CO_2 Purity	%	-	-	-	N/A
Energy Balance – Power					
Production Facility	GWh / yr	87	87	-	-

Joint LCA and TEA assumptions

- Feedstock and fuel are natural gas.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.

9.2.2 Steam Naphtha Reforming (SNR)

Table 37: SNR Technology Process Data

Variable	Units	SNR
Inputs		
Feedstock	kWh_{th}/kg	38.71
Fuel	kWh_{th}/kg	13.26
Raw Water	kg/kgH_2	5.10
Cooling Water	kg/kgH_2	1,265.38
Energy		
Process Power Requirement	kWh_e/kg	1.39
System Power Generation	kWh_e/kg	1.20
Compression Power Requirement	kWh_e/kg	1.10
Emissions		
CO_2	kg/kgH_2	1.29
Products		
Hydrogen	kg/kgH_2	1.00
CO_2 Export	kg/kgH_2	11.64
Process		
Purity of Hydrogen	%	99.99%
Hydrogen Export Pressure	bar	200.00
CO_2 Export Pressure	bar	110.00
CO_2 Capture Rate	%	90.00%

Table 38: SNR Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO2 Emissions	4. CO2 Export
Feedstock	GWh / yr	3,053	-	-	-
Fuel	GWh / yr	1,046	-	-	-
Water	ktonne / yr	402	-	-	-
CO_2	ktonne / yr	-	-	102	918
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	99.99	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	110
CO_2 Purity	%	-	-	-	99.99
Energy Balance – Power					
Production Facility	GWh / yr	102	-	-	-

Joint LCA and TEA assumptions

- Feedstock is naphtha and fuel is natural gas.
- Feedstock, fuel, raw water and cooling water requirement based on a combination of information from literature (Linde[279]) and stakeholder engagement.
- Power requirmeent based on Case 3 from IEAGHG's study on SMR[38], using SMR as a proxy for SNR.
- Process emissions are based on multiplying the feedstock and fuel requirement by the carbon intensity of naphtha ($0.2639kgCO_2/kWh_{th}$) and natural gas ($0.2038kgCO_2/kWh_{th}$).
- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy use for the carbon capture process has been considered.

[279] Linde 2016, Hydrogen

- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.

9.2.3 Partial Oxidation (POX)

Table 39: POX Technology Process Data

Variable	Units	POX[280]
Inputs		
Feedstock	kWh_{th}/kg	31.85 – 36.75
Raw Water	kg/kgH_2	6.40 – 9.20
Oxygen	kg/kgH_2	2.47 – 3.19
Energy		
Process Power Requirement	kWh_e/kg	2.30 – 2.87
Compression Power Requirement	kWh_e/kg	0.81 – 0.95
Emissions		
CO_2	kg/kgH_2	0.29 – 0.34
Waste		
Water	kg/kgH_2	1.26 – 1.82
Products		
Hydrogen	kg/kgH_2	1.00
CO_2 Export	kg/kgH_2	7.48 – 9.24
Process		
Purity of Hydrogen	%	>97.00%
Hydrogen Export Pressure	bar	200
CO_2 Export Pressure	bar	110
CO_2 Capture Rate	%	95.70% - 96.98%

Table 40: POX Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO_2 Emissions	4. CO2 Export
Feedstock	GWh / yr	2,512 – 2,899	-	-	-
Fuel	GWh / yr	-	-	-	-
Water	ktonne / yr	505 – 726	-	-	-
CO_2	ktonne / yr	-	-	23 – 27	590 – 729
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	>97.00	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	110
CO_2 Purity	%	-	-	-	99.99
Energy Balance – Power					
Production Facility	GWh / yr	245 – 301	-	-	-

Joint LCA and TEA assumptions

- Feedstock is assumed to be vacuum residue, however many options are possible – this will require different process variables.
- Assume that the total power requirement includes power for the ASU and CO_2 compression.
- The electricity demand of an ASU for the production of 1 kg of O_2 is different in different sources, resulting in a range. The quantity used in this study is based on a recent value (representing an efficient ASU), at lower end of the range[281].

[280] Information provided from various stakeholder engagement activities and supported by literature
[281] Linde 2009, Enhanced Cryogenic Air Separation A proven Process applied to Oxyfuel

- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy use for the carbon capture process has been considered.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.

LCA assumptions

- Heavy fuel oil is used as a proxy for vacuum residue in the LCA modelling, due to lack of data in the LCA database (Ecoinvent 3.6).

TEA assumptions

- Assume that the raw water is the same quality as boiling feedwater.

9.2.4 Hygenic Earth Energy (HEE)

Table 41: HEE process data

Variable	Units	HEE H_2 Turbine[282]	HEE Grid Powered
Inputs			
Oxygen	kg/kgH_2	15.17	12.00
Oil Feedstock	kWh_{th}/kgH_2	49.32	39.02
Energy			
Process Power Requirement	kWh_e/kg	-	2.94
Compressor Power Requirement	kWh_e/kg	-	1.10
Emissions			
CO_2	kg/kgH_2	-	-
Products			
Hydrogen	kg/kgH_2	1.00	1.00
CO_2 Export	kg/kgH_2	13.90	11.00
Process			
Purity of Hydrogen	%	99.90%	99.90%
Hydrogen Export Pressure	bar	200	200
CO_2 Capture Rate	%	100.00%	100.00%

Joint LCA and TEA Assumptions

- Limited data availability, as data comes only from Proton Technologies. Furthermore, the technology has low TRL which introduces uncertainties on how the technology will be deployed and thus on the input and output data.
- Feedstock is assumed to be oil.
- It is assumed there are no leakages of CO_2, methane or other hydrocarbons to atmosphere, facilitating a 100% capture rate. Given the common practices in the oil and gas industry, this might be an optimistic assumption.
- It is assumed no flaring or venting from reservoir occurs. Given the common practices in the oil and gas industry, this is an optimistic assumption.
- The initial energy required to start up the hydrogen production is not included in this study. While this energy may be significant, there is no data available on this topic.
- The auxiliary component requirements, such as the membrane, are not accounted for in this analysis.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.
- Based on stakeholder engagement, it could be assumed that the HEE hydrogen plant produces its own electricity, by converting part of the produced hydrogen to electricity in a gas turbine. In this case, the electricity is used for the hydrogen plant itself and the production of oxygen. Therefore, both electricity use, and oxygen use do not have a carbon footprint. However, connecting the hydrogen plant to the local electricity grid is technically equally feasible, and this choice is likely a matter of financial optimization.
- For the hydrogen turbine scenario:
  - This process assumes that 76 tonnes of hydrogen are used to power Proton Technologies' balance of plant, equivalent to $2.94kWhe/kgH_2$, and that an additional 28 tonnes of hydrogen are used to power the compression to export hydrogen at 200 bar.

[282] Data collection based on stakeholder engagement with Proton Technologies and available literature from webinars and publications. Proton 2021, The Proton Process

    - Total power Requirement is zero since all power is generated internally.
- For the grid power scenario:
    - Energy requirement of $2.94kWh_e/kgH_2$ is based on a $0.245kWh_e/kgO_2$ ASU power requirement[281].
    - Costs associated with forming a grid connection are not considered.

LCA assumptions

- The palladium membrane is said to last as long as the lifetime of the well and as such is not taken it into account for the impact assessment (as it is considered part of the capital goods).

Table 42: HEE Mass and Energy Balance - H_2 Turbine

Process Stream	Units	1. System Demand	2. System Output	3. CO_2 Emissions	4. CO2 Export
Feedstock	GWh / yr	3,890	-	-	-
Fuel	GWh / yr	-	-	-	-
Water	ktonne / yr	-	-	-	-
CO_2	ktonne / yr	-	-	-	1,096
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	99.90	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	Well Pressure
CO_2 Purity	%	-	-	-	N/A
Energy Balance – Power					
Production Facility	GWh / yr	-	-	-	-

Table 43: HEE Mass and Energy Balance – Grid Power

Process Stream	Units	1. System Demand	2. System Output	3. CO_2 Emissions	4. CO2 Export
Feedstock	GWh / yr	3,078	-	-	-
Fuel	GWh / yr	-	-	-	-
Water	ktonne / yr	-	-	-	-
CO_2	ktonne / yr	-	-	-	868
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	99.90	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	Well Pressure
CO_2 Purity	%	-	-	-	N/A
Energy Balance – Power					
Production Facility	GWh / yr	319	-	-	-

9.2.5 CO_2 Transport and Storage

Pipeline and shipping cost data for CO2 transport was taken from previous studies conducted by Element Energy: 'Shipping CO2 – UK Cost Estimation Study'[169] and 'Carbon Capture, Usage and Storage Deployment at Dispersed Sites'[283]. This is displayed for analysed regions for pipelines in Table 44 and Table 45, and for shipping in Table 46. The final CO_2 T&S figures are given in Table 48.

Table 44: Technical data for CO_2 pipelines in analysed regions

CO_2 pipeline transport	Units	Algeria (In Salah)	Algeria (Porthos)	Algeria (France – Mas de Madames)	Netherlands (Porthos)	Brazil (Roncador)	UAE (ADNOC Onshore)
Compressor Power	kWh/tCO_2/km	0.01	0.36	0.36	0.18	0.02	0.04
Pipeline Diameter	Inches (mm)	18 (457.2)	8.0 (203.2)	8.0 (203.2)	10.0 (254.0)	14.0 (355.6)	14.0 (355.6)
Wall Thickness	mm	28.84	12.82	12.82	16.02	22.43	22.43
Area of intersection (wall only)	mm^2	38,807	7,666	7,666	11,978	23,476	23,476
Area of NG pipeline wall	mm^2	29,531	29,531	29,531	29,531	29,531	29,531
CO2 Pipeline Materials/NG Pipeline Materials	%	131	26	26	41	79	79
Lifetime	Years	25	25	25	25	25	25

Table 45: Technical data for CO_2 pipelines in analysed regions

CO_2 pipeline transport	Units	Republic Congo	Gabon	Angola	Libya	Iraq	Kuwait	Saudi Arabia
Compressor Power	kWh/tCO_2/km	0.91	1.82	0.91	0.03	0.09	0.17	0.03
Pipeline Diameter	Inches (mm)	10 (254.0)	10 (254.0)	14 (355.6)	16 (406.4)	12 (304.8)	10 (254.0)	14 (355.6)
Wall Thickness	mm	16.02	16.02	22.43	25.63	19.22	16.02	22.43
Area of intersection (wall only)	mm^2	11,978	11,978	23,476	30,663	17,248	11,978	23,476
Area of NG pipeline wall	mm^2	29,531	29,531	29,531	29,531	29,531	29,531	29,531
CO_2 Pipeline Materials/ NG Pipeline Materials	%	41	41	79	104	58	41	79
Lifetime	Years	25	25	25	25	25	25	25

[283] Element Energy for BEIS 2020, CCS Deployment at dispersed industrial sites

Table 46: Technical data for CO_2 shipping

		Algeria (Porthos)	Algeria (France – Mas de Madames)
# Ships	#	1	1
Ship Capacity	tCO_2	30,000	8,000
Annual Trips per Ship	#	24	87
Trip Duration	Hours	270	59
Fuel for Transport	MWh/day	339	256
LNG CO_2 Intensity	tCO_2/MWh	0.18	0.18
Grid Intensity	tCO_2/ MWh	0.23	0.23
Liquifying Energy Requirement	kWh/tCO_2	24.6	24.6
Lifetime	Years	25	25
Total Emissions from Liquefaction & Shipping	tCO_2/year	20,491	13,840
Emissions	tCO_2/km/year	5.46	17.30

Information on shipping is given in the Element Energy CO_2 Shipping Report[169].

Table 47: CO_2 transport distances

Country	Scenario	Onshore pipeline (km)	Shipping (km)	Offshore pipeline (km)
UAE	Local CO_2 T&S (base)	250	-	-
Iraq	Local CO_2 T&S (base)	105	-	-
Kuwait	Local CO_2 T&S (base)	5	-	50
	Shipping CO_2 T&S	5	450	300
Saudi Arabia	Local CO_2 T&S (base)	305	-	-
Republic of Congo	Local CO_2 T&S (base)	10	-	50
Gabon	Local CO_2 T&S (base)	5	-	60
Angola	Local CO_2 T&S (base)	10	-	200
	Shipping CO_2 T&S	10	9500	20
Algeria	Local CO_2 T&S (base)	1200	-	-
	Shipping CO_2 T&S scenario 1	5	3750	20
	Shipping CO_2 T&S scenario 2	5	800	20
Libya	Local CO_2 T&S (base)	360	-	-
Brazil	Local CO_2 T&S (base)	30	-	450
Netherlands	Local CO_2 T&S (base)	30	-	20

Table 48: CO_2 T&S costs by region and year

Storage Region	Unit	2020	2050
UAE (ADNOC Onshore)	€ / tCO_2	42.93	14.40
Iraq - local	€ / tCO_2	18.03	7.70
Kuwait - local	€ / tCO_2	14.35	6.13
Kuwait (Uthmaniyah)	€ / tCO_2	131.46	38.06
Saudi Arabia (Uthmaniyah)	€ / tCO_2	38.34	16.38
Republic of Congo - local	€ / tCO_2	66.55	19.27
Gabon - local	€ / tCO_2	66.55	19.27
Angola – local	€ / tCO_2	132.78	38.44
Angola (Porthos)	€ / tCO_2	204.10	59.09
Algeria (In Salah)	€ / tCO_2	155.87	52.29
Algeria (Porthos)	€ / tCO_2	123.92	35.87
Algeria (France - Mas de Madames)	€ / tCO_2	91.58	26.51
Libya	€ / tCO_2	38.34	16.38
Brazil (Roncador)	€ / tCO_2	245.60	71.1
Netherlands (Porthos)	€ / tCO_2	54.56	14.39

Joint LCA and TEA assumptions

- Lifetime of the pipelines is assumed to be 25 years.
- Pipeline compressor power is a function of flow rate, pipeline utilisation, pressure drop and compressor efficiency. The pipeline diameter is a function of flowrate and pipeline length. The final combination of compressor power and pipeline diameter are such that a pressure drop of 1MPa is maintained across the pipeline. As a result, the compressor power for each technology is fixed whilst the pipeline diameter varies. This is presented in the Appendices, Section 9.2.5.

LCA assumptions

- Pipelines are modelled as onshore pipelines.
- In the LCA model, the pipeline that is used for CO_2 transportation is modelled as a natural gas pipeline as the LCA database contains no information on pipelines for CO_2 transport. As the diameter and thickness of the CO_2 pipeline is different than the natural gas pipeline, the pipeline is scaled based on the differences in the area (intersection) of the pipelines.

9.2.6 H_2 and CO_2 Transport Routes

Potential hydrogen and CO_2 transport routes have been considered for both shipping and pipeline scenarios for all regions considered in this analysis (other than the Netherlands where only short distance pipelines are considered). Where HEE technology has been deployed, CO_2 T&S has not been considered; however, CO_2 shipping routes from neighbouring countries where POX or SNR technology has been considered can be used as proxies for initial cost assumptions.

For all regions, local CO_2 storage (via pipeline) has been considered in the base case scenario. CO_2 shipping has been considered for one country per region in the Middle East, West Africa, and North Africa. These are listed below:

- Kuwait to Saudi Arabia
- Angola to the Netherlands
- Algeria to the Netherlands

Middle East

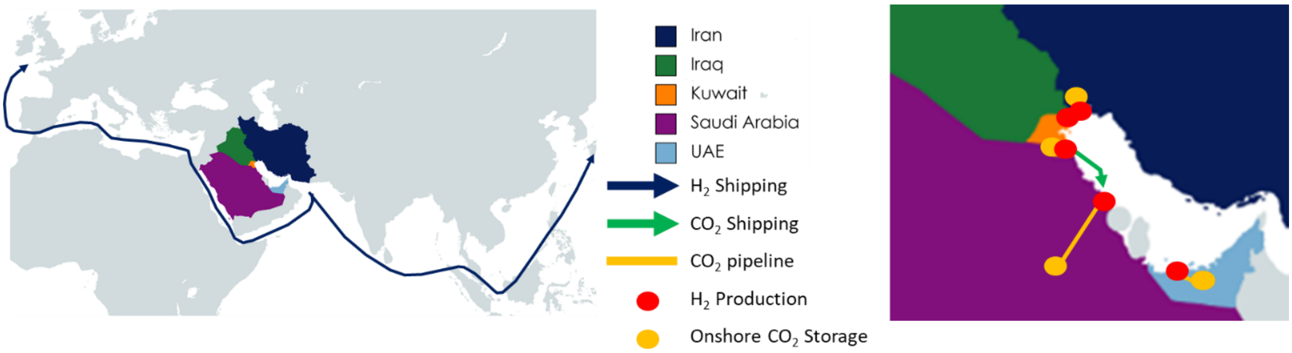

Figure 110: H_2 shipping routes from the Middle East (left) and CO_2 T&S options (right)

West Africa

Figure 111: H_2 and CO_2 shipping routes from West Africa (left) and CO_2 T&S options (right)

North Africa

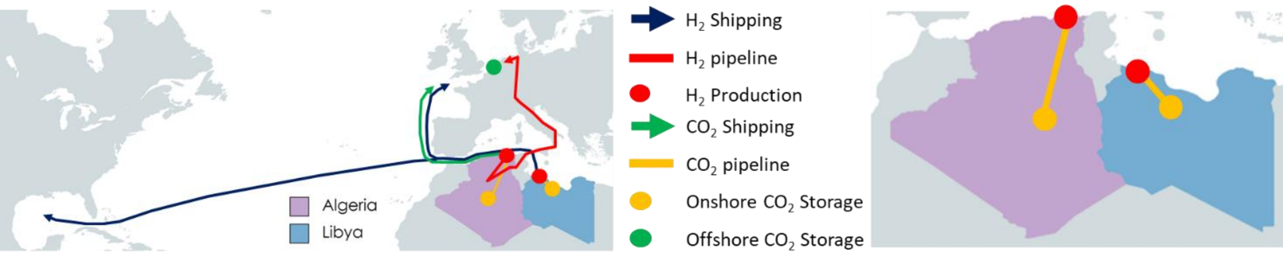

Figure 112: H_2 and CO_2 shipping/pipeline routes from North Africa (left) and CO2 T&S options (right)

Latin America

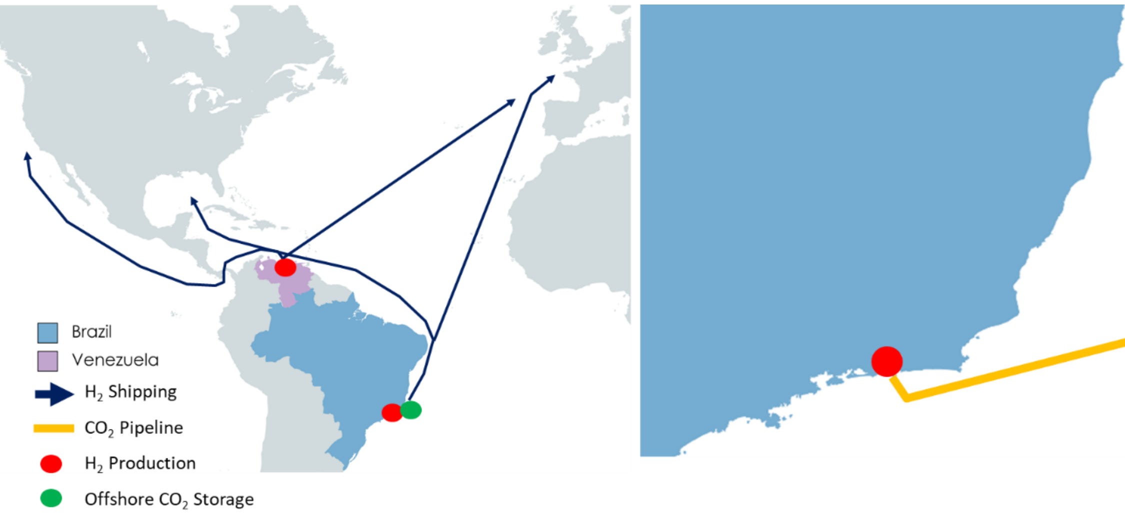

Figure 113: H_2 shipping routes from Latin America (left) and CO_2 T&S options (right)

9.2.7 Hydrogen Compression

Specific Energy of Compression

The hydrogen export pressures reported in the literature vary significantly depending on the source. It is therefore important to homogenise these processes to have the same functional unit of hydrogen per technology. This corresponds to hydrogen at a pressure of 200 bar.

To calculate the specific energy requirement, an inhouse engineering tool was used based on the increase in pressure, the temperature of the stream, the isentropic coefficient of the gas and the efficiency of the compressor. It was assumed that:

- The compressor efficiency varied between 65% and 80%; an average was taken to give the specific energy requirement[284].
- The pressure ratio was restricted to six. This means that the output pressure from the compressor could not be greater than six times the input pressure. Where this occurred, the number of compression stages was increased until the pressure ratio criterium was satisfied.

To exemplify the impact of compression stages on the specific energy requirement, the specific energy required to compress hydrogen to 200 bar from different export pressures are shown below for three compression stages.

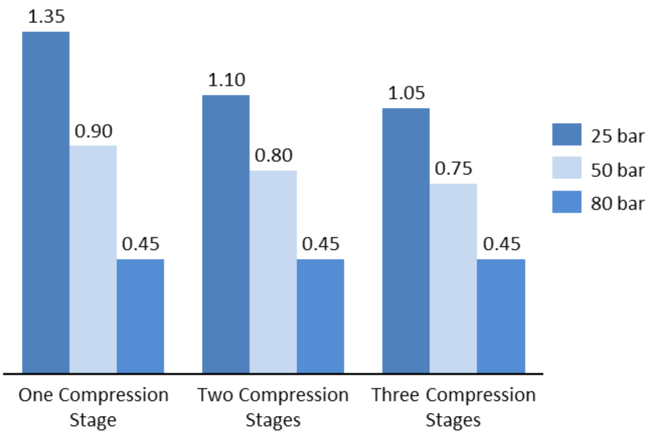

Figure 114: Specific compression energy needed to increase from stated inlet pressure to 200 bar (kWh/kgH_2)[285]

Capital Costs and Fixed Operational Costs

The capital cost of the compressors is based on the average of three correlations for determining capital cost of compressors. These are Yang & Ogden[286], NASFuture[287] and Towler & Sinott[288]. These correlations use the compressor power to determine the capital cost. CAPEX is presented as $(2020). To convert to Euros, an exchange rate of 0.8757€/$ is used[221].

Yang & Ogden

$$Capex = 2{,}341\ \times Compressor\ Power(MW)^{0.9}$$

NASFuture

$$Capex = 3{,}099 \times Compressor\ Power\ (MW)^{0.8}$$

Towler & Sinott, 2013

$$Capex = 2.5 \times (304{,}800 + 1.69 \times Compressor\ Power^{1.5})$$

Fixed OPEX is assumed to be 5% of CAPEX.

284 NREL 2014, Hydrogen Station Compression, Storage, and Dispensing Technical Status and Costs
285 Compression energy is a function of the pressure increase and the number of compression stages. The given energy requirement is for a one stage compression system, increasing the pressure from 50 to 200 bar.
286 Yang and Ogden 2006, Determining the lowest cost hydrogen delivery mode
287 Thomas 2015, Sustainable Transport Options for the 21st Century
288 Towler & Sinnott 2013, Chemical Engineering Design

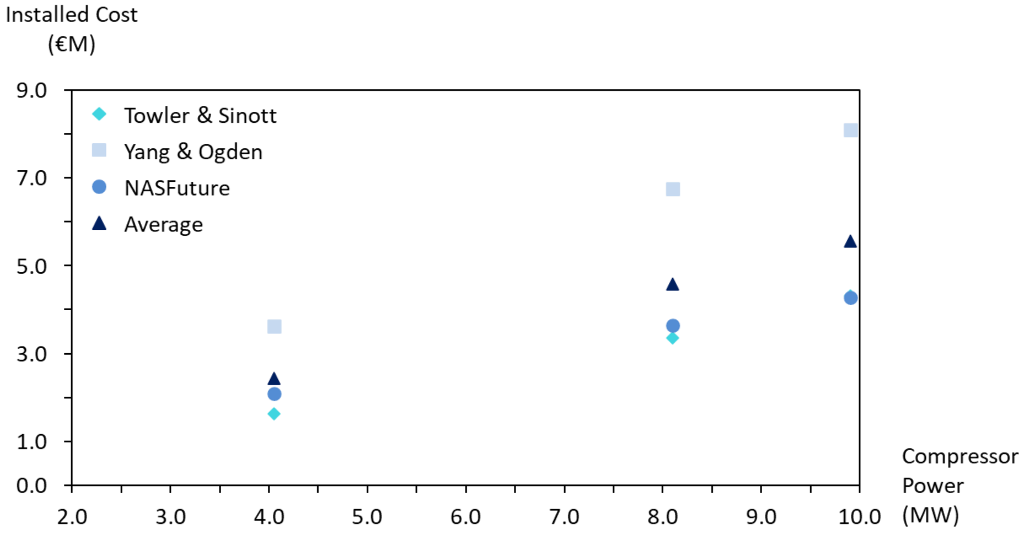

Figure 115: Capital cost of compressor by power (MW) and by methodology

9.2.8 Carbon footprint of feedstock and electricity production

Feedstocks

The carbon footprint for the feedstocks used in this study are given here in Table 49. The source of these carbon footprints is the LCA database Ecoinvent v3.6.

Table 49: Carbon footprint of feedstock production by region

Country		UAE	Iran	Iraq	Kuwait	Saudi Arabia
Natural Gas	$kgCO_2 / m^3$	$3.8x10^{-1}$	N/A	$3.3x10^{-1}$	N/A	N/A
Naphtha	$kgCO_2$ / kg	$2.8x10^{-1}$	N/A	$4.7x10^{-1}$	N/A	N/A
Oil / Vacuum Residue	$kgCO_2$ / kg	N/A	N/A	N/A	$3.8x10^{-1}$	$3.8x10^{-1}$
Country		**Nigeria**	**Republic of Congo**	**Equatorial Guinea**	**Gabon**	**Angola**
Natural Gas	$kgCO_2 / m^3$	N/A	N/A	N/A	N/A	$3.3x10^{-1}$
Naphtha	$kgCO_2$ / kg	N/A	$3.3x10^{-1}$	N/A	N/A	$4.7x10^{-1}$
Oil / Vacuum Residue	$kgCO_2$ / kg	N/A	$3.8x10^{-1}$	N/A	$3.8x10^{-1}$	N/A
Country		**Algeria**	**Libya**	**Brazil**	**Venezuela**	**Netherlands**
Natural Gas	$kgCO_2 / m^3$	N/A	$3.3x10^{-1}$	N/A	N/A	$3.0x10^{-1}$
Naphtha	$kgCO_2$ / kg	N/A	$4.7x10^{-1}$	N/A	N/A	$3.0x10^{-1}$
Oil / Vacuum Residue	$kgCO_2$ / kg	$3.6x10^{-1}$	N/A	$3.3x10^{-1}$	N/A	N/A

Not all data used in this research was available in the same unit in different sources. Table 50 shows the conversion factors used in the LCA models.

Table 50: Conversion factors used in the LCAs

Variable	Value + Unit	Used for which technology
LHV Naphtha	12.47 kWh/kg	Steam naphtha reforming (SNR)
LHV Vacuum residue	10.58 kWh/kg	Partial oxidation (POX)
HHV Natural gas[289]	11.68 kWh/m^3	Benchmark (SMR), Steam naphtha reforming (SNR)

[289] The sources used for the different technologies reported other lower heating values for natural gas. In Ecoinvent, the unit of natural gas is m^3 and as a default a **higher** heating value is used. Therefore, the average of the LHV's provided by the different sources to high heating value (HHV) and m^3 is converted using 1.08 HHV/LHV (H21 NoE) and the default density used in Ecoinvent, which is 0.84 kg/m^3.

The Carbon Footprint of Electricity in 2020

The country specific carbon footprints of electricity in 2020 used in this study are presented in Table 51.

Table 51: Current country specific carbon footprint of electricity production 2020 and source

Country	Technology	Current carbon footprint of electricity (kg CO2 eq./kWh)	Modelling / Ecoinvent process
The Netherlands	SMR (benchmark)	0.48	Based on (CE Delft, 2020)[290]
Angola	SNR	0.38	Electricity, high voltage {AO}| market for electricity, high voltage
Iraq	SNR	1.04	Electricity, high voltage {IQ}| market for electricity, high voltage
Libya	SNR	0.74	Electricity, high voltage {LY}| market for electricity, high voltage
United Arab Emirates	SNR	0.53	Electricity, high voltage {AE}| market for electricity, high voltage
Algeria	POX	0.61	Electricity, high voltage {DZ}| market for electricity, high voltage
Brazil	POX	0.19	Electricity, high voltage {BR}| market group for electricity, high voltage
Gabon	POX	0.32	Electricity, high voltage {GA}| market for electricity, high voltage
Kuwait	POX	0.82	Electricity, high voltage {KW}| market for electricity, high voltage
R. Congo	POX	0.71	Electricity, high voltage {RAF}| market group for
Saudi Arabia	POX	1.01	Electricity, high voltage {SA}| market for
E. Guinea	HEE	0.71	Electricity, high voltage {RAF}| market group for
Iran	HEE	0.64	Electricity, high voltage {IR}| market for
Nigeria	HEE	0.48	Electricity, high voltage {NG}| market for electricity, high voltage
Venezuela	HEE	0.32	Electricity, high voltage {VE}| market for electricity, high voltage

The carbon footprint of 100% renewable electricity in 2020

In Section 5.2, the TEA 2050 scenario assumes a supply of 100% renewable electricity is available, equivalent to a 100% renewable electricity supply in the Netherlands in 2020. The carbon footprint of this electricity is 32.9 g CO_2-eq./kWh (only wind and solar, based on (CE Delft, 2020)).

The carbon footprint of electricity in 2030

In Sensitivity Analysis 1 (see Section 6.3.3), the LCA of the different hydrogen production scenarios is estimated for 2030 by modelling the technologies using an expected country specific carbon footprint of electricity for 2030. The country specific 2030 electricity carbon footprints is estimated using the following methodology:

1. NL: Direct 2030 emissions based on (PBL, 2020), indirect 2030 emissions based on production mix in (PBL, 2020) modelled using Ecoinvent processes[291].

[290] CE Delft 2018, Emissiekentallen elektriciteit This source was used to determine the carbon footprint of the Dutch electricity mix rather than the Ecoinvent electricity process for the Netherlands, as (CE Delft, 2020) contains a more recent information on the specific electricity mix of the Netherlands. This mix has been modelled using the existing Ecoinvent background processes to make sure that, next to the carbon footprint, other environmental impact categories are taken into account as well.
[291] For the Netherlands, the following Ecoinvent processes were used to model the indirect emissions of electricity:

2. Algeria, Angola, Republic Congo, Equatorial Guinea, Gabon and Nigeria: the carbon footprint of 2019 and 2030 electricity mix as indicated in World Energy Outlook 2020 ((IEA, 2020), Table A.3, stated policies scenario) for Africa is modelled in Ecoinvent[292]. The change in carbon footprint between those two was calculated as a change factor and multiplied by the current country specific carbon footprint from Ecoinvent (see following formula in which CSCF = country specific carbon footprint and RSCF = region specific carbon footprint (Africa for Algeria and Nigeria, Middle East for United Arab Emirates and Brazil for Brazil):

3. $$CSCF_{Ecoinvent,2030} = \left(100\% - \frac{RSCF_{IEA,2019} - RSCF_{IEA,2030}}{RSCF_{IEA,2019}}\right) * CSCF_{Ecoinvent,2019}$$

4. Brazil: carbon footprint of 2019 and 2030 electricity mix as indicated in World Energy Outlook 2020 ((IEA, 2020), Table A.3, stated policies scenario) for Brazil modelled in Ecoinvent[293]. The change between those two was calculated as a change factor and multiplied by the current country specific carbon footprint from Ecoinvent (see formula above).
5. Iran, Iraq, Kuwait, Libya, Saudi Arabia and United Arab Emirates: carbon footprint of 2019 and 2030 electricity mix as indicated in World Energy Outlook 2020 ((IEA, 2020), Table A.3, stated policies scenario) for Middle East modelled in Ecoinvent[294]. The change between those two was calculated as a change factor and multiplied by the current country specific carbon footprint from Ecoinvent (see formula above).
6. Venezuela: carbon footprint of 2019 and 2030 electricity mix as indicated in World Energy Outlook 2020 ((IEA, 2020), Table A.3, stated policies scenario) for Central and South America modelled in Ecoinvent. The change between those two was calculated as a change factor and multiplied by the current country specific carbon footprint from Ecoinvent (see formula above).

The resulting country specific 2030 carbon footprints of electricity are presented in Table 52.

- Natural gas: Electricity, high voltage {NL}| heat and power co-generation, natural gas, combined cycle power plant, 400MW electrical
- Nuclear: Electricity, high voltage {NL}| electricity production, nuclear, pressure water reactor
- Other fossil: Electricity, high voltage {NL}| treatment of blast furnace gas, in power plant | Cut-off, U
- Wind: Electricity, high voltage {NL}| electricity production, wind, 1-3MW turbine, offshore
- Photovoltaic: Electricity, low voltage {NL}| electricity production, photovoltaic, 570kWp open ground installation, multi-Si
- Biomass: Electricity, high voltage {NL}| heat and power co-generation, wood chips, 6667 kW, state-of-the-art 2014
- Rest: Electricity, high voltage {NL}| heat and power co-generation, natural gas, conventional power plant, 100MW electrical

[292] For Africa, the following Ecoinvent processes were used to model the carbon footprint of electricity in 2019 and 2030 according to the World Energy Outlook 2020:
- Natural gas: Electricity, high voltage {RoW}| electricity production, natural gas, conventional power plant
- Coal: Electricity, high voltage {RoW}| electricity production, hard coal
- Oil: Electricity, high voltage {RoW}| electricity production, oil
- Nuclear: Electricity, high voltage {RoW}| electricity production, nuclear, pressure water reactor
- Hydro: Electricity, high voltage {RoW}| electricity production, hydro, run-of-river
- Biomass: Electricity, high voltage {RoW}| heat and power co-generation, wood chips, 6667 kW, state-of-the-art 2014
- Wind: Electricity, high voltage {RoW}| electricity production, wind, 1-3MW turbine, onshore
- Solar/photovoltaic: Electricity, high voltage {RoW}| electricity production, solar tower power plant, 20 MW

[293] For Brazil, the same Ecoinvent processes were used to model the carbon footprint of electricity in 2019 and 2030 according to the World Energy Outlook 2020 as for Africa (see footnote **Error! Bookmark not defined.**), with the exception of:
- Hydro: Electricity, high voltage {RoW}| electricity production, hydro, reservoir, tropical region

[294] For the Middle East and Central and South America, the same Ecoinvent processes were used to model the carbon footprint of electricity in 2019 and 2030 according to the World Energy Outlook 2020 as for Africa (see footnote **Error! Bookmark not defined.**), with the exception of:
- Solar / photovoltaic: Electricity, high voltage {RoW}| electricity production, solar thermal parabolic trough, 50 MW

Table 52: 2030 country specific expected carbon footprint (method explained in this section)

Country	Technology	Estimated 2030 carbon footprint of electricity (kg CO_2 eq./kWh)	Reduction of the carbon footprint compared to the current
The Netherlands	SMR (benchmark)	0.16	-67%
Angola	SNR	0.28	-25%
Iraq	SNR	0.92	-12%
Libya	SNR	0.56	-25%
United Arab Emirates	SNR	0.47	-12%
Algeria	POX	0.46	-25%
Brazil	POX	0.14	-28%
Gabon	POX	0.24	-25%
Kuwait	POX	0.73	-12%
R. Congo	POX	0.53	-25%
Saudi Arabia	POX	0.89	-12%
E. Guinea	HEE	0.53	-25%
Iran	HEE	0.57	-12%
Nigeria	HEE	0.36	-25%
Venezuela	HEE	0.24	-26%

9.3 Data and Assumptions used in TEA

9.3.1 CAPEX and Fixed OPEX

CAPEX and Fixed OPEX data used for the economic assessment of oil-based technologies is displayed in Table 53 and Table 54 respectively.

The capital costs used in this analysis are not tailored to be country specific. It is assumed that deploying SNR in the UAE costs the same as deploying the technology in the Netherlands. The cost components are also not broken down in this study, i.e., differences between contingencies between two reports is not considered, only that the costs are accounted for.

Table 53: CAPEX data from literature

Technology	CAPEX Min [€ / kW]	CAPEX Max [€ / kW]	CAPEX Average [€ / kW]	Range [+/-%]	Assumptions
SMR	993	1,070	1,031	+/- 3.7%	H21 - Equipment, Bulk, Indirects, Construction, Home Office, CMT, Other, Owner's Cost, Project Management, Insurances, Contingency - Capture Rate, 91.2% IEAGHG - Direct Materials, Construction, EPC Services, Other, Contingency - Capture Rate, 90%
SNR	993	1,070	1,031	+/- 3.7%	H21 - Equipment, Bulk, Indirects, Construction, Home Office, CMT, Other, Owner's Cost, Project Management, Insurances, Contingency - Capture Rate, 91.2% IEAGHG - Direct Materials, Construction, EPC Services, Other, Contingency - Capture Rate, 90%
POX	965	1,035	1,000	+/- 3.5%	University of Florida - Data from the University of Florida included equipment, facility, construction interest, start-up expenses and working capital Stakeholders
HEE	597	697	647	+/- 7.8%	Proton Technologies - Details on bottom-up approach outlined on below
Benchmark SMR		570		N/A	IEAGHG - Direct Materials, Construction, EPC Services, Other, Contingency

Table 54: Fixed OPEX data assumptions

Technology	Fixed OPEX Min [€ / kW/yr]	Fixed OPEX Max [€ / kW/yr]	Fixed OPEX Average [€ / kW/yr]	Range [+/-%]	Assumptions
SMR	30	42	36	+/- 17.1%	H21 - Fixed OPEX/CAPEX = 3% - Fixed OPEX breakdown not provided IEAGHG - Direct labour, Admin/general overheads, Insurance and taxes, Maintenance - Fixed OPEX/CAPEX = 3.9%
SNR	30	42	36	+/- 17.1%	**SMR case used as a proxy.** H21 - Fixed OPEX/CAPEX = 3% - Fixed OPEX breakdown not provided IEAGHG - Direct labour, Admin/general overheads, Insurance and taxes, Maintenance - Fixed OPEX/CAPEX = 3.9%
POX	37	40	39	+/- 3.5%	Limited data available on fixed OPEX breakdown. - Fixed OPEX/CAPEX = 3.9% (Average of SMR and ATR breakdowns used)
HEE	23	27	25	+/- 7.8%	Limited data available on fixed OPEX breakdown. - Fixed OPEX/CAPEX = 3.9% (Average of SMR and ATR breakdowns used)
Benchmark SMR		23		N/A	IEAGHG - Direct labour, Admin/general overheads, Insurance and taxes, Maintenance - Fixed OPEX/CAPEX = 4.0%

HEE – Bottom-Up Approach

CAPEX cost requirements of HEE hydrogen production followed a bottom-up approach considering four major items: hydrogen generator, hydrogen membrane, hydrogen well and ASU as displayed in Figure 116. Cost assumptions were based on commercially available technology where available and scaled to HEE requirements. All costs were scaled to the standardised 300MW_{LHV} production capacity and are shown in Table 55 based on commercial data availability. For scenarios where grid electricity is used as part of the process, there is no cost associated with the hydrogen generator.

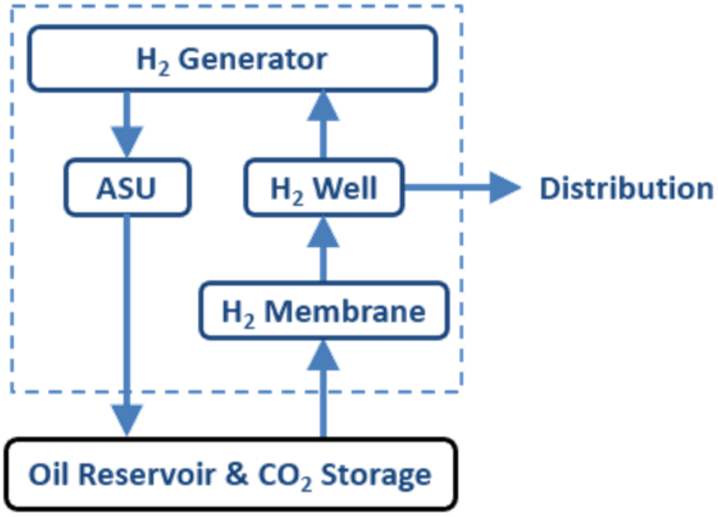

Figure 116: HEE CAPEX items considered in dashed box

Table 55: HEE CAPEX cost breakdown

CAPEX Cost Breakdown	Cost (€/kW)	Assumptions
ASU	348	- Cost assumption based on data from 5,800t/d Air Liquide ASU - €200 million[295]. - Scaled down to 2,593t/d for HEE requirement using scaling factor of 0.6.
Hydrogen Membrane	18	- Cost assumption based on data from US Department of Energy report on palladium membranes for hydrogen separation[296]. - Membrane area required calculated using Flux = 7.6 kg/h/m^2.
Hydrogen Generator	231	- Cost estimates from data provided by Proton Technologies in Global Energy Show webinar[297]. - Generator cost scaled down to standardised 300MW capacity using scaling factor of 0.6.

Assumptions around the hydrogen well costs were developed based on data published from the oil and gas industry. The number of hydrogen wells required for a $300MW_{LHV}$ facility was determined based on the average daily well production in the oil and gas industry. The assumptions for the hydrogen well cost is displayed in Table 56.

[295] Air Liquide 2018, South Africa: Air Liquide starts up the world's largest oxygen production unit
[296] US Department of Energy 2012, High-Performance Palladium Based Membrane for Hydrogen Separation and Purification
[297] Global Energy Show 2020, Zero Emissions, Low Cost Hydrogen Production from Oil Reservoirs

Table 56: HEE H_2 well cost CAPEX breakdown

H_2 Well CAPEX Breakdown	Units			Assumptions
Drilling Depth	km	2	6	• Data collected based on two drilling depths • Average depth taken for cost estimates in the Journal of Petroleum Science and Engineering[298].
Well Cost (per Well)	€ million	2.6	17.5	
Number of Wells	#	3		• Number of wells selected based on data from EIA[299, 300]. Average production rate in the oil industry assumed 1,650 boe/day/well. • Equivalent hydrogen production assumed = 80.6 tonnes/day (H_2 LHV = 33.3 kWh/kg) or 112 MW per Well • 300MW production requires approximately 2.7 Wells
No Well Cost	€/kW	0.0		• Assumes legacy infrastructure utilised
Well Cost Included	€/kW	100.7		• Assumes well cost curve from the oil and gas industry

[298] Lukawski et al 2014, Cost analysis of oil, gas, and geothermal well drilling
[299] EIA 2020, US Oil and Natural Gas Wells by Production rate
[300] EIA 2020, US Crude oil and natural gas production in 2019 hit records with fewer rigs and wells

9.3.2 Hydrogen Distribution and Storage

Hydrogen distribution costs were split into three streams for both pipeline and shipping scenarios. These are displayed in Figure 117 with distances shown in Table 58.

- **Stream 1 –** Short distance pipeline transportation from hydrogen production facility to primary distribution method.
- **Stream 2 –** Long distance shipping/pipeline distribution option.
- **Stream 3 –** Short distance pipeline transportation to point of hydrogen demand.

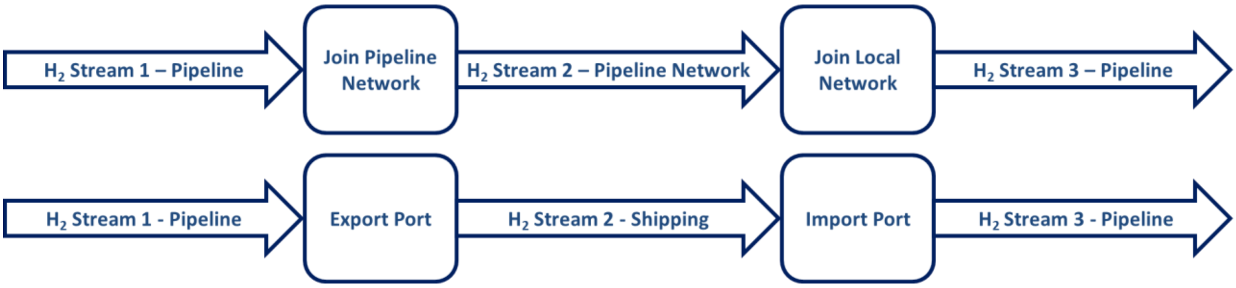

Figure 117: H_2 distribution options

For each hydrogen distribution carrier, the conversion/reconversion costs are provided in Table 57. Hydrogen distribution correlations were derived from costs curves in the IEA's 'Future of Hydrogen'[4] for shipping and pipeline. For shipping, this was focussed on ammonia, liquid organic hydrogen carriers and liquid hydrogen. For pipelines, this was focussed on retrofitted and new gaseous hydrogen pipelines over medium to long-range distances. Although the initial and final hydrogen pipelines are less than 50km, the pricing for medium distance pipelines were used as the annual throughput is ~79ktonnes/yr. Each stream was multiplied by the transportation distance and combined with the relevant conversion / reconversion costs for each hydrogen carrier. The cost of hydrogen storage was assumed to be included in the hydrogen distribution cost component, as per the assumptions from the IEA's 'Future of Hydrogen[4].

Table 57: Conversion and reconversion costs for hydrogen carriers

Conversion costs		NH3	LOHC	LH2
2020	€ / kgH_2	0.88	0.35	0.88
2040	€ / kgH_2	0.53	0.32	0.54
Reconversion costs		**NH3**	**LOHC**	**LH2**
2020	€ / kgH_2	0.66	0.88	-
2040	€ / kgH_2	0.47	0.41	-

In the techno-economic analysis, short pipelines are a key output of the sensitivity analysis. For direct comparisons, a pipeline length of 30km is used.

Table 58: Hydrogen distribution distances

Origin	Destination	Onshore pipeline (km)	Shipping (km)	Long Distance pipeline (km)	Onshore pipeline (km)
UAE	Asia	20	13,000	-	50
	Western Europe	20	12,600	-	50
	Local	30	-	-	-
Iran	Asia	75	11,800	-	30
	Western Europe	75	12,300	-	10
	Local	30	-	-	-
Iraq	Asia	100	11,800	-	30
	Western Europe	100	12,300	-	10
	Local	30	-	-	-
Kuwait	Asia	10	11,650	-	30
	Western Europe	10	12,200	-	10
	Local	30	-	-	-
Saudi Arabia	Asia	5	11,450	-	30
	Western Europe	5	12,000	-	10
	Local	20	-	-	-
Nigeria	Western Europe	150	8,600	-	50
	Western Europe (Pipe)	150	-	7,000	50
	North America	150	11,400	-	50
	Local	30	-	-	-
Republic of Congo	Western Europe	10	9,500	-	10
	North America	10	12,150	-	50
	Local	30	-	-	-
Equatorial Guinea	Western Europe	20	9,500	-	10
	North America	20	11,600	-	50
	Local	20	-	-	-
Gabon	Western Europe	10	8,500	-	10
	North America	10	11,700	-	50
	Local	30	-	-	-
Angola	Western Europe	10	9,250	-	10
	North America	10	12,500	-	50

	Local	30	-	-	-
Algeria	Western Europe	5	3,750	-	50
	Western Europe (Pipe)	550	-	3,700	50
	North America	5	7,500	-	50
	Local	30	-	-	-
Libya	Western Europe	30	4,500	-	10
	North America	30	11,000	-	50
	Local	30	-	-	-
Brazil	Western Europe	30	9,800	-	50
	North America	30	9,900	-	50
	Local	30	-	-	-
Venezuela	Western Europe	10	7,800	-	10
	North America	10	4,000	-	50
	Local	30	-	-	-
Netherlands	Local	30	-	-	-

9.3.3 Feedstock

Electricity Prices

The central forecast for electricity prices by region is reported in Table 59.

UAE

- 2020 price based on 'Abu Dhabi Distribution Co'[301] weighted average of peak and off-peak tariffs. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020'[302] reference case electricity prices.

Iran

- 2020 price based on 'The World Bank – Doing Business 2020'[303] price of electricity. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Iraq

- 2020 price based on 'Powering Iraq: Challenges Facing the Electricity Sector in Iraq'[304] industrial electricity price. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Kuwait

- 2020 price based on 'The World Bank – Doing Business 2020' price of electricity. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Saudi Arabia

- 2020 price based on 'Saudi Electric Company'[305] industrial electricity tariff. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Nigeria

- 2020 price based on 'Global Petrol Prices'[306]. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Republic of Congo

- 2020 price based on average of 'Energie Electrique du Congo'[307] industrial electricity tariff and 'The World Bank – Doing Business 2020' price of electricity. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Equatorial Guinea

- 2020 price based on 'The World Bank – Doing Business 2020' price of electricity. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

[301] ADDC 2018, Rates and Tariffs 2018

[302] EIA 2020, Annual Energy Outlook 2020
[303] The World Bank 2020, Doing Business
[304] Mills and Salman 2020, Powering Iraq: Challenges Facing the Electricity Sector in Iraq
[305] Saudi Electric Company 2018, Tariffs and Connection Fees
[306] Global Petrol Prices 2021, Electricity Prices
[307] Energie Electrique Du Congo 2020, Tarifs d'electricite

Gabon

- 2020 price based on 'The World Bank – Doing Business 2020' price of electricity. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Angola

- 2020 price based on average of 'The World Bank – Angola – Electricity Sector Improvement Project' and 'The World Bank – Doing Business 2020' price of electricity. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Algeria

- 2020 price based on 'Global Petrol Prices'. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Libya

- 2020 price based on average of 'Dynamic – Energy and Water Solutions' heavy industry electricity tariff and 'The World Bank – Doing Business 2020' price of electricity. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Brazil

- 2020 price based on 'Statista'[308] Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Venezuela

- 2020 price based on 'Energy Transformation – Latin America & Caribbean'[309]. Outward trend to 2050 based on forward looking trends from 'EIA – Annual Energy Outlook 2020' reference case electricity prices.

Netherlands

- 2020 price based on 'Global Petrol Prices'[310] and 'Statista'[311]. Outward trend to 2030 based on wholesale electricity price forecasts from 'Netherlands Climate and Energy Outlook 2020'[312] and data for the Netherlands provided by 'Denmark's Draft Integrated National Energy and Climate Plan[313]. Industrial electricity tax applied assuming that the ratio in 2020 remains constant for outward trends to 2050.
- Outward trend to from 2030 to 2050 based on forward looking trends from 'EU Energy Outlook 2050'[314].

[308] Statista 2021, Average electricity consumption rate in Brazil in 2020
[309] Energy Transformation 2019, Latin America & Caribbean
[310] Global Petrol Prices 2021, Electricity Prices
[311] Statista 2021, Prices of electricity for industry in the Netherlands from 2008 to 2020
[312] Netherlands Environmental Assessment Agency 2020, Netherlands Climate and Energy Outlook 2020
[313] Energi-Forsynings-og Klimaministeriet 2018, Denmarks Draft Integrated National Energy and Climate Plan
[314] Energy Brain Blog 2019, EU Energy Outlook 2050

Table 59: Electricity prices by region

		2020	2030	2050
UAE	€ / MWh	62.93	63.55	61.06
Iran	€ / MWh	45.53	45.98	44.18
Iraq	€ / MWh	43.78	44.22	42.49
Kuwait	€ / MWh	6.13	6.19	5.95
Saudi Arabia	€ / MWh	40.73	41.14	39.53
Nigeria	€ / MWh	82.82	91.80	77.33
Republic of Congo	€ / MWh	82.26	83.08	79.83
Equatorial Guinea	€ / MWh	152.36	153.87	147.85
Gabon	€ / MWh	167.25	168.90	162.29
Angola	€ / MWh	31.52	31.84	30.59
Algeria	€ / MWh	27.88	30.90	26.03
Libya	€ / MWh	95.07	96.01	92.25
Brazil	€ / MWh	71.87	79.67	67.11
Venezuela	€ / MWh	140.11	141.49	135.95
Netherlands	€ / MWh	94.05	103.17	107.82

Natural Gas Prices

The central forecast for natural gas prices by region is reported in Table 60.

UAE, Kuwait, Said Arabia

- 2020 price based on 'PWC – The Outlook for gas in the GCC'[315]. Outward trend to 2050 based on 'EIA – Annual Energy Outlook 2020'[316] reference case scenario.

Iran

- 2020 price based on 'The Geopolitics of Natural Gas – Case Study: Iran'[317]. Outward trend to 2050 based on 'EIA – Annual Energy Outlook 2020' reference case scenario.

Iraq

- 2020 price based on 'Global Petrol Prices'[318] natural gas prices. Outward trend to 2050 based on 'EIA – Annual Energy Outlook 2020' reference case scenario.

Nigeria, Republic of Congo, Equatorial Guinea, Gabon, Angola, Algeria, Libya

- 2020, 2030 and 2050 prices based on data provided by the EU Commission's 'Energy Projections for African Countries'[319].

Brazil

- 2020 price based on 'Global Petrol Prices'[318] and 'S & P Global Platts'[320]. Outward trend to 2050 based on 'EIA – Annual Energy Outlook 2020'[316] reference case scenario.

Venezuela

- 2020 price based on 'Global Petrol Prices' natural gas prices. Outward trend to 2050 based on 'EIA – Annual Energy Outlook 2020' reference case scenario.

Netherlands

[315] PWC 2019, The outlook for gas in the GCC
[316] EIA 2020, Annual Energy Outlook 2020
[317] Maloney, S 2014, The Geopolitics of Natural Gas
[318] Global petrol Prices 2021, Natural Gas Prices
[319] EU Commission 2019, Energy Projections for African Countries
[320] S&P Global 2020, After Petrobras, part III: Brazil's upstream is a gas supply source ready to be unleashed

- 2020 and 2030 prices based on CE Delft's 'Energy and electricity price scenarios 2020-2023-2030'[321]. Outward trend to 2050 based on EWI Research Scenarios 'The Energy Market in 2030 and 2050'[322].

Table 60: Natural gas prices by region

		2020	2030	2050
UAE	€ / MWh	2.95	3.93	4.48
Iran	€ / MWh	5.98	7.95	9.07
Iraq	€ / MWh	12.85	17.09	19.50
Kuwait	€ / MWh	6.02	8.01	9.14
Saudi Arabia	€ / MWh	2.47	3.28	3.75
Nigeria	€ / MWh	31.91	38.52	42.00
Republic of Congo	€ / MWh	31.91	38.52	42.00
Equatorial Guinea	€ / MWh	31.91	38.52	42.00
Gabon	€ / MWh	31.91	38.52	42.00
Angola	€ / MWh	22.73	27.44	29.92
Algeria	€ / MWh	31.91	38.52	42.00
Libya	€ / MWh	31.91	38.52	42.00
Brazil	€ / MWh	48.33	64.30	73.37
Venezuela	€ / MWh	21.89	29.13	33.24
Netherlands	€ / MWh	21.10	27.40	30.67

Naphtha Prices

The central forecast for naphtha prices by region is reported in Table 61.

UAE

- 2020 price based on average of data provided from 'Statista'[323] and 'Zawya'[324]. Outward trend to 2050 based on reference oil price from 'EIA – International Energy Outlook 2019'[325].

Netherlands

- 2020 price based on average of data provided from 'Statista'[323] and 'ICIS'[326]. Outward trend to 2050 based on reference oil price from 'EIA – International Energy Outlook 2019'[325].

Iraq, Angola, Libya

- 2020 price based on data from 'Statista'[323]. Outward trend to 2050 based on reference oil price from 'EIA – International Energy Outlook 2019'[325].

Table 61: Naphtha prices by region

Year		2020	2030	2050
UAE	€ / MWh	20.72	26.16	32.28
Iraq	€ / MWh	32.68	39.69	48.97
Angola	€ / MWh	32.68	39.69	48.97
Libya	€ / MWh	32.68	39.69	48.97
Netherlands	€ / MWh	59.64	75.45	93.09

[321] CE Delft 2017, Energy and Electricity Price Scenarios
[322] EWI 2018, The Energy Market in 2030 and 2050
[323] Statista 2021, Price of Naphtha worldwide from 2017 to 2021
[324] Zawya 2019, ADNOC sets H1 2020 naphtha offers at 81-108% higher vs FY 2019
[325] EIA 2019, International Energy Outlook 2019
[326] ICIS 2018, Europe Hexane Prices up naphtha solvent and white spirit widen

Oil Prices

The central forecast for oil prices by region is reported in Table 62. This is based on the average of the 'EIA – Low Oil Price' and 'EIA – Reference Oil Price' forecasts out to 2050 provided in the 'EIA – International Energy Outlook 2019'[325].

Table 62: Oil/Vacuum Residue prices by region

Year		2020	2030	2050
All Regions	€ / MWh	25.82	31.37	38.71

Steam Prices

The central forecast for oil prices by region is reported in Table 63. For all regions, steam is priced based on data from 'NREL – H2A: Hydrogen Analysis Production Models'[327].

Table 63: Steam prices by region

Year		2020	2030	2050
All Regions	€ / kg	0.0018	0.0018	0.0018

[327] NREL 2020, H2A: Hydrogen Analysis Production Models

9.4 Background Processes and Data Used in the LCA study

In this appendix, the LCA background data used for modelling is listed. Most of the background data retrieved from the LCA database Ecoinvent, v3.6.

9.4.1 Benchmark: SMR NL (based on natural gas) without CCS

Table 64: Environmental impact modelling, sources for hydrogen production via SMR using natural gas as a feedstock in the Netherlands

Input	Modelling / Ecoinvent v3.6 process
Natural gas (feedstock)	Natural gas, high pressure {NL}| market for
Natural gas (fuel)	Natural gas, high pressure {NL}| market for
Electricity	Based on (CE Delft, 2020)[328]
Raw water	Tap water {Europe without Switzerland}| market for
Cooling water	Water, cooling, salt, ocean
Output	**Modelling / Ecoinvent v3.6 process**
Carbon dioxide, fossil	Carbon dioxide, fossil
Wastewater	Wastewater, average {Europe without Switzerland}| market for wastewater, average
Electricity	Based on (CE Delft, 2020)[329]

[328] This source was used to determine the carbon footprint of the Dutch electricity mix rather than the Ecoinvent electricity process for the Netherlands, as (CE Delft, 2020) contains more recent information on the specific electricity mix of the Netherlands. This mix has been modelled using the existing Ecoinvent background processes to make sure that, next to the carbon footprint, other environmental impact categories are taken into account as well.

[329] See footnote **Error! Bookmark not defined.** for more information about this source.

9.4.2 Steam Naphtha Reforming

Table 65: Environmental impact modelling, sources for hydrogen production via naphtha steam reforming

Input	Modelling / Ecoinvent v3.6 process
Naphtha	The Netherlands: Naphtha {RER}| market for United Arab Emirates: Naphtha {RoW}| market for Angola: Naphtha {RoW}| market for Libya: Naphtha {RoW}| market for Iraq: Naphtha {RoW}| market for
Natural gas	The Netherlands: Natural gas, high pressure {NL}| market for United Arab Emirates: Natural gas, high pressure {RoW}| market for Angola: Natural gas, high pressure {RoW}| market for Libya: Natural gas, high pressure {RoW}| market for Iraq: Natural gas, high pressure {RoW}| market for
Electricity	The Netherlands: Based on (CE Delft, 2020)[330] United Arab Emirates: Electricity, high voltage {AE}| market for electricity, high voltage Angola: Electricity, high voltage {AO}| market for electricity, high voltage Libya: Electricity, high voltage {LY}| market for electricity, high voltage Iraq: Electricity, high voltage {IQ}| market for electricity, high voltage
Raw water	The Netherlands: Tap water {Europe without Switzerland}| market for United Arab Emirates: Tap water {RoW}| market for Angola: Tap water {RoW}| market for Libya: Tap water {RoW}| market for Iraq: Tap water {RoW}| market for
Cooling water	Water, cooling, salt, ocean (input from nature)
Output	**Ecoinvent v3.6 process**
Carbon dioxide, fossil	Carbon dioxide, fossil (output to air)

[330] This source was used to determine the carbon footprint of the Dutch electricity mix rather than the Ecoinvent electricity process for the Netherlands, as (CE Delft, 2020) contains a more recent information on the specific electricity mix of the Netherlands. This mix has been modelled using the existing Ecoinvent background processes to make sure that, next to the carbon footprint, other environmental impact categories are taken into account as well.

9.4.3 Partial oxidation (POX)

Table 66: Environmental impact modelling, sources for hydrogen production via partial oxidation (POX) of oil

Input	Modelling / Ecoinvent v3.6 process
Vacuum residue	Algeria: Heavy fuel oil {RoW}| market for Brazil: Heavy fuel oil {BR}| market for heavy fuel oil Gabon: Heavy fuel oil {RoW}| market for Republic Congo: Heavy fuel oil {RoW}| market for Kuwait: Heavy fuel oil {RoW}| market for Saudi Arabia: Heavy fuel oil {RoW}| market for
Oxygen	Based on Oxygen, liquid {RER}| market for, having changed the electricity demand in the subprocess "Oxygen, liquid {RER}| air separation, cryogenic" from 1,42 kWh/kg O_2 to 0.245 kWh/kg O_2 and electricity from either Algeria, Brazil, Gabon, Republic Congo, Kuwait or Saudi Arabia (see next row in this table)
Electricity	Algeria: Electricity, high voltage {DZ}| market for electricity, high voltage Brazil: Electricity, high voltage {BR}| market group for electricity, high voltage Gabon: Electricity, high voltage {GA}| market group for electricity, high voltage Republic Congo: Electricity, high voltage {RAF}| market group for electricity, high voltage Kuwait: Electricity, high voltage {KW}| market for electricity, high voltage Saudi Arabia: Electricity, high voltage {SA}| market for
Raw water	Algeria: Tap water {RoW}| market for Brazil: Tap water {BR}| market for tap water Gabon: Tap water {RoW}| market for Republic Congo: Tap water {RoW}| market for Kuwait: Tap water {RoW}| market for Saudi Arabia: Tap water {RoW}| market for
Output	**Ecoinvent v3.6 process**
Carbon dioxide	Carbon dioxide, fossil
Wastewater	Wastewater, average {RoW}| market for wastewater, average

9.4.4 HEE

Table 67: Environmental impact modelling, sources for hydrogen production via HEE using electricity produced within the hydrogen production facility using own hydrogen

Input	Modelling / Ecoinvent v3.6 process
Crude oil in well	Oil, crude, feedstock, 41 MJ per kg (input from nature)
Oxygen	Not applicable – has no carbon footprint as it is produced using its own electricity
Electricity	Not applicable – has no carbon footprint as it is produced using own hydrogen

Table 68: Life cycle inventory of hydrogen production via HEE using electricity from the grid

Input	Modelling / Ecoinvent v3.6 process
Crude oil in well	Oil, crude, feedstock, 41 MJ per kg (input from nature)
Oxygen	Based on Oxygen, liquid {RER}| market for, having changed the electricity demand in the subprocess “Oxygen, liquid {RER}| air separation, cryogenic" from 1,42 kWh/kg O_2 to 0.245 kWh/kg O_2 and electricity from either Nigeria, Equatorial Guinea, Venezuela or Iran (see next row in this table)
Electricity	Nigeria: Electricity, high voltage {NG}| market for electricity, high voltage Equatorial Guinea: Electricity, high voltage {RAF}| market for electricity, high voltage Venezuela: Electricity, high voltage {VE}| market for electricity, high voltage Iran: Electricity, high voltage {IR}| market for

9.5 Other Environmental Impact Categories

As explained in Section 6 the focus of this LCA is on the carbon footprint as an environmental impact indicator. Additionally, to show possible environmental trade-offs between carbon footprint and other impact categories, the following impact categories are included in this Appendix:

- Acidification
- Human toxicity (cancer effects)
- Human toxicity (non-cancer effects)
- Ozone depletion
- Particulate matter
- Ionising radiation human health
- Ionising radiation ecosystems
- Photochemical ozone formation
- Terrestrial eutrophication
- Freshwater eutrophication
- Marine eutrophication
- Freshwater ecotoxicity
- Land use
- Mineral, fossil and renewable resource depletion
- Water resource depletion
- Cumulative non-renewable energy demand.

In the results of each of the environmental impact categories listed above are provided for the different hydrogen production scenarios. Section 6.1 gives a more detailed description of the LCA methods used to calculate these results. These results are merely provided to facilitate a comparison of environmental trade-offs between the different scenarios. Comparisons between the impact categories are more difficult to make, i.e., weighing factors should be used to be able to compare the results.

The results are shown in Table 69, Table 70 and Table 71. The most important conclusion to draw from these results is that even though the studied technologies can have lower carbon footprints, trade-offs in other environmental impact categories can occur. It is recommended to study this more thoroughly in further research.

Table 69: Other environmental impact categories for SMR blue hydrogen technology in 2020

Impact category	Benchmark SMR, no CCS (TRL 9)	SNR (TRL 9)					Unit
	NL	Angola	Iraq	Libya	NL	UAE	
Global warming potential	10,13	3,39	4,28	4,02	3,44	3,62	kg CO2 eq.
Ozone depletion	9,43E-07	2,25E-06	2,36E-06	2,29E-06	2,30E-06	2,21E-06	kg CFC-11 eq.
Human toxicity, non-cancer effects	7,19E-08	1,87E-07	1,94E-07	2,11E-07	1,79E-07	1,83E-07	CTUh
Human toxicity, cancer effects	3,05E-08	2,78E-08	2,39E-08	3,91E-08	1,79E-08	2,89E-08	CTUh
Particulate matter	2,25E-04	1,53E-03	1,93E-03	1,66E-03	1,05E-03	1,19E-03	kg PM2.5 eq.
Ionizing radiation HH	3,84E-02	7,09E-01	7,39E-01	7,14E-01	6,99E-01	6,83E-01	kBq U235 eq.
Ionizing radiation E (interim)	2,36E-07	5,04E-06	5,25E-06	5,07E-06	4,97E-06	4,85E-06	CTUe
Photochemical ozone formation	4,10E-03	1,42E-02	1,65E-02	1,55E-02	1,19E-02	1,29E-02	kg NMVOC eq.
Acidification	4,34E-03	2,31E-02	2,86E-02	2,42E-02	1,80E-02	1,88E-02	molc H+ eq.
Terrestrial eutrophication	1,02E-02	3,60E-02	4,42E-02	4,03E-02	3,05E-02	3,15E-02	molc N eq.
Freshwater eutrophication	5,33E-05	2,58E-05	2,52E-05	3,09E-05	4,66E-05	2,65E-05	kg P eq.
Marine eutrophication	9,74E-04	3,27E-03	4,02E-03	3,66E-03	2,73E-03	2,86E-03	kg N eq.
Freshwater ecotoxicity	2,58E+00	2,82E+00	3,20E+00	2,99E+00	1,45E+00	2,49E+00	CTUe
Land use	2,67E+00	2,97E+01	3,10E+01	3,07E+01	2,82E+01	2,95E+01	kg C deficit
Water resource depletion	1,07E-03	1,01E-03	6,88E-04	2,54E-03	1,51E-03	-4,87E-04	m3 water eq.
Mineral, fossil & ren resource depletion	1,77E-05	6,37E-05	6,56E-05	6,78E-05	6,28E-05	6,36E-05	kg Sb eq.
CED, non-renewable	176,09	218,21	232,07	229,82	227,69	225,91	MJ

Table 70: Other environmental impact categories for POX blue hydrogen technology in 2020

Impact category	Benchmark SMR, no CCS (TRL 9)	POX - oil (TRL 9)						Unit
	NL	Algeria	Brazil	Gabon	Kuwait	R. Congo	Saudi Arabia	
Global warming potential	10,13	4,57	2,35	2,74	4,59	4,16	5,39	kg CO2 eq.
Ozone depletion	9,43E-07	2,14E-06	1,99E-06	2,03E-06	2,34E-06	2,06E-06	2,44E-06	kg CFC-11 eq.
Human toxicity, non-cancer effects	7,19E-08	2,99E-07	2,57E-07	1,37E-07	1,80E-07	3,84E-07	2,31E-07	CTUh
Human toxicity, cancer effects	3,05E-08	9,93E-08	3,74E-08	1,78E-08	2,11E-08	3,34E-08	3,48E-08	CTUh
Particulate matter	2,25E-04	1,86E-03	2,01E-03	1,19E-03	2,73E-03	2,08E-03	3,02E-03	kg PM2.5 eq.
Ionizing radiation HH	3,84E-02	6,95E-01	6,92E-01	6,77E-01	7,88E-01	7,04E-01	8,04E-01	kBq U235 eq.
Ionizing radiation E (interim)	2,36E-07	4,95E-06	4,95E-06	4,81E-06	5,60E-06	5,01E-06	5,71E-06	CTUe
Photochemical ozone formation	4,10E-03	1,79E-02	1,29E-02	1,18E-02	2,00E-02	1,92E-02	2,25E-02	kg NMVOC eq.
Acidification	4,34E-03	2,28E-02	2,08E-02	1,87E-02	3,84E-02	3,86E-02	4,21E-02	molc H+ eq.
Terrestrial eutrophication	1,02E-02	5,12E-02	3,73E-02	3,13E-02	6,00E-02	5,91E-02	6,72E-02	molc N eq.
Freshwater eutrophication	5,33E-05	5,86E-05	4,63E-05	2,36E-05	2,64E-05	1,43E-04	3,25E-05	kg P eq.
Marine eutrophication	9,74E-04	4,69E-03	3,43E-03	2,86E-03	5,48E-03	5,33E-03	6,14E-03	kg N eq.
Freshwater ecotoxicity	2,58E+00	2,67E+00	1,90E+00	1,58E+00	3,06E+00	2,17E+00	3,87E+00	CTUe
Land use	2,67E+00	3,18E+01	2,73E+01	2,78E+01	3,20E+01	2,92E+01	3,29E+01	kg C deficit
Water resource depletion	1,07E-03	1,96E-02	1,02E-02	1,38E-02	1,30E-02	1,57E-02	-1,06E+00	m3 water eq.
Mineral, fossil & ren resource depletion	1,77E-05	8,25E-05	6,34E-05	5,92E-05	6,72E-05	6,11E-05	7,16E-05	kg Sb eq.
CED, non-renewable	1,76E+02	215,13	170,01	182,78	205,95	217,42	194,51	MJ

Table 71: Other environmental impact categories for HEE blue hydrogen technology in 2020

Impact category	Benchmark SMR, no CCS (TRL 9)	HEE (TRL 4-6)				Unit
	NL	E. Guinea	Iran	Nigeria	Venezuela	
Global warming potential	10,13	2,91	2,66	2,00	1,36	kg CO2 eq.
Ozone depletion	9,43E-07	1,37E-07	2,50E-07	1,09E-07	1,48E-07	kg CFC-11 eq.
Human toxicity, non-cancer effects	7,19E-08	3,01E-07	7,51E-08	3,26E-08	3,85E-08	CTUh
Human toxicity, cancer effects	3,05E-08	2,22E-08	8,06E-09	5,06E-09	5,69E-09	CTUh
Particulate matter	2,25E-04	1,24E-03	6,81E-04	1,11E-04	5,91E-04	kg PM2.5 eq.
Ionizing radiation HH	3,84E-02	4,86E-02	5,97E-02	6,51E-03	4,23E-02	kBq U235 eq.
Ionizing radiation E (interim)	2,36E-07	3,57E-07	4,42E-07	4,93E-08	3,03E-07	CTUe
Photochemical ozone formation	4,10E-03	1,06E-02	5,33E-03	2,40E-03	3,87E-03	kg NMVOC eq.
Acidification	4,34E-03	2,54E-02	8,64E-03	1,93E-03	7,54E-03	molc H+ eq.
Terrestrial eutrophication	1,02E-02	3,93E-02	1,69E-02	8,37E-03	1,36E-02	molc N eq.
Freshwater eutrophication	5,33E-05	1,34E-04	1,01E-05	5,07E-06	4,61E-06	kg P eq.
Marine eutrophication	9,74E-04	3,50E-03	1,54E-03	7,61E-04	1,24E-03	kg N eq.
Freshwater ecotoxicity	2,58E+00	1,01E+00	1,33E+00	2,06E-01	6,70E-01	CTUe
Land use	2,67E+00	3,59E+00	2,99E+00	2,59E+00	2,50E+00	kg C deficit
Water resource depletion	1,07E-03	4,61E-02	2,50E-02	4,63E-02	4,26E-02	m3 water eq.
Mineral, fossil & ren resource depletion	1,77E-05	1,27E-05	1,31E-05	1,16E-05	1,14E-05	kg Sb eq.
CED, non-renewable	176,09	194,51	193,59	187,76	170,71	MJ

9.6 Results of the Analysis

9.6.1 TEA Sensitivities

UAE SNR

Deployments in the 2020s

Two cases are explored for SNR in the UAE from 2020. These are summarised in Table 72 with results displayed in Figure 121.

Overview & Base Case

- Case 1 is both the Base Case and the lowest cost pathway. It assumes central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Alternative H_2 Distribution (Shipping to Asia)

- The difference of only €0.02/kg between shipping to Europe and Asia demonstrates that hydrogen production from the UAE could easily support both markets where distribution costs can be brought down through

Table 72: Summary of cases analysed for SNR in the UAE in 2020

Sensitivity	Case 1	Case 2
Type	Baseline / Lowest Cost Pathway	Alternative H_2 Distribution (Shipping)
Capex & Fixed Opex	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Central Case
CO_2 Price	Central Case	Central Case
CO_2 T&S	UAE (Pipe)	UAE (Pipe)
H_2 Distribution	W. Europe (Ship)	Asia (Ship)

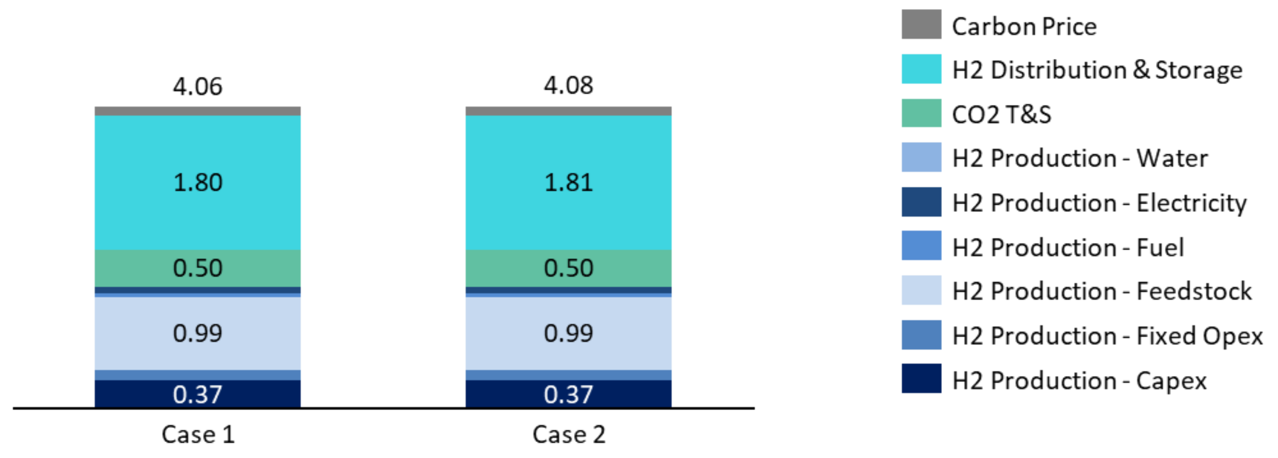

Figure 118: LCOH for SNR (TRL 9) in the UAE in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 119. As previously discussed, the feedstock price and H_2 distribution fee are the most significant cost components. Variations in all cost components other than the cost of feedstock and CO_2 T&S fee do not change the LCOH by more than +/- 5%. The most significant variation comes from the cost of feedstock due to the wide range of naphtha prices. The naphtha cost is varied by + / - 92% and this changes the LCOH by + / - 22.5%. Variation to the Capex, fixed Opex, electricity demand and carbon price has a cumulative impact of + / - 3.2% on the LCOH.

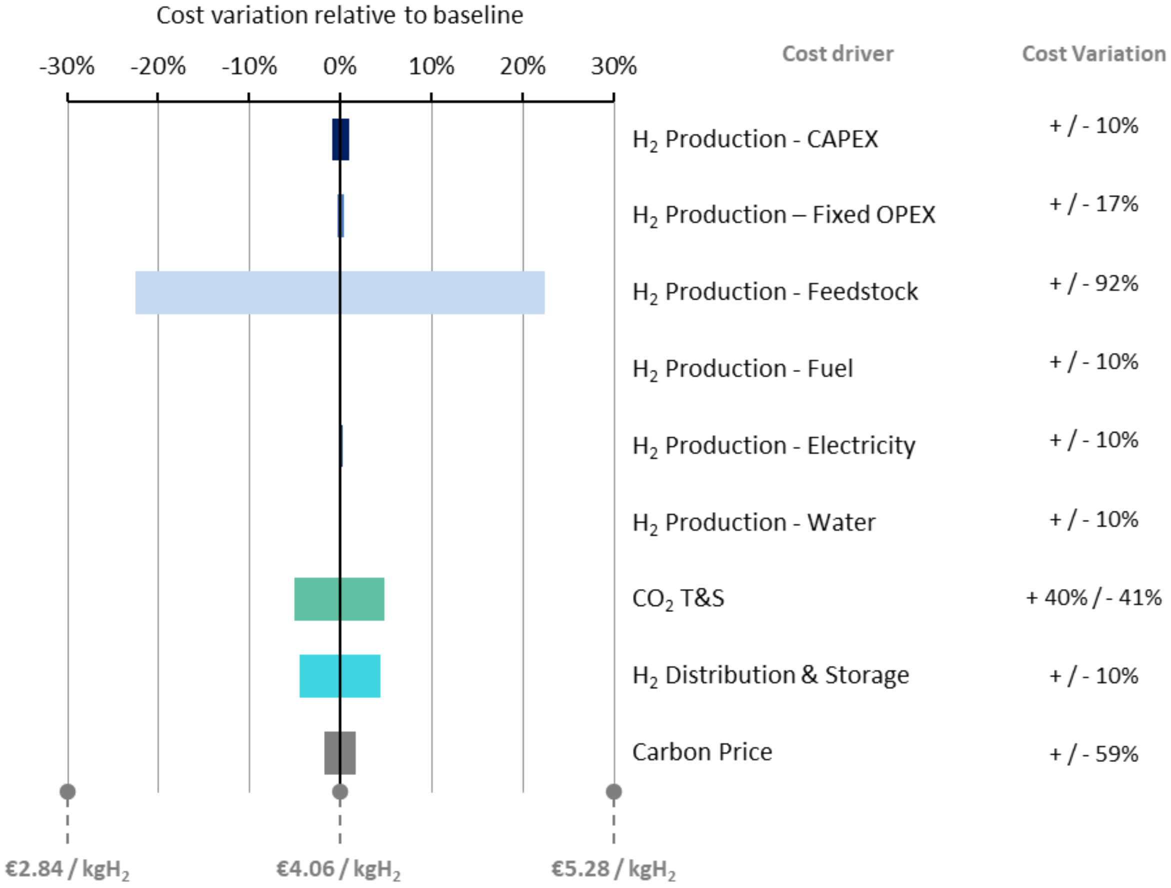

Figure 119: Levelised cost of hydrogen for SNR (TRL 9) in the UAE base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Four cases are explored for SNR in the UAE from 2050. These are summarised in Table 73 with results displayed in Figure 120.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%.
- This has a marginal impact on the LCOH, with a 2.2% reduction on the Base Case.

Case 3 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs, reducing the LCOH by 34.1%.

Case 4 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 and Case 3 reveals a pathway to low-cost blue hydrogen from the UAE. The base case LCOH is reduced from €3.72/kgH_2 to €2.38/kgH_2; a 36.0% reduction.

Table 73: Summary of cases analysed for SNR in the UAE in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4
Type	Baseline	Capex Reduction	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Central Case
CO_2 Price	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	UAE (Pipe)	UAE (Pipe)	UAE (Pipe)	UAE (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

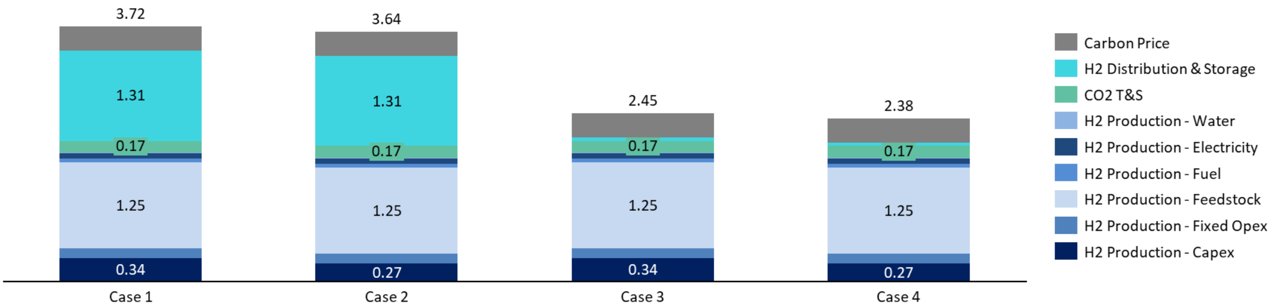

Figure 120: LCOH for SNR (TRL 9) in the UAE in 2050 (€/kgH_2)

Iran HEE

Deployments in the 2020s

Seven cases are explored for HEE in Iran from 2020. These are summarised in Table 74 with results displayed in Figure 121.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.
- Process electricity demand is supplied by an on-site hydrogen generator.

Case 2 - Grid Electricity Supply

- Case 2 replaces the on-site hydrogen generator with electricity supplied from the grid.

Case 3 – Low Cost Well Option

- Where the technology operator can access existing infrastructure and pre-existing wells, it is possible to save upfront capital costs associated with well drilling based on Element Energy's bottom up cost analysis. Whilst the Capex is reduced by 14.4%, the overall LOCH is only reduced by 1.4%.

Case 4 – Oil from Well is Free

- In the base case, it is assumed that the technology operator has to account for the fact that oil is not sold to the market but instead converted to hydrogen.
- Where the value of this oil can be significantly depreciated or where the oil cannot be economically extracted, it can be valued as having zero cost.
- This significantly reduces the LCOH by 40.9%.

Case 5 – Oil from Well is Free & Grid Electricity

- Case 5 is the same as Case 4 with the on-site hydrogen generator replaced with electricity supplied from the grid.

Case 6 – Alternative H_2 Distribution (W. Europe Shipping)

- Case 6 proves that Iran could just as viably distribute hydrogen to Western Europe as opposed to Asia. The distance increase of c. 550km only increases the LCOH by 0.3%.

Case 7 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 3 and 4 identifies a pathway to lower cost blue hydrogen from Iran. The base case LCOH is reduced from €3.69/kgH_2 to €2.13/kgH_2; a 42.3% reduction.

Table 74: Summary of cases analysed for HEE in Iran in 2020

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Type	Baseline	Baseline & Grid Electricity	Low Cost Well Option	Oil from Well Priced as Zero	Oil from Well Priced as Zero & Grid Electricity	Alternative H2 Distribution (Pipeline)	Lowest Cost Pathway
Capex & Fixed Opex	New Well	New Well	Old Well	New Well	New Well	New Well	Old Well
Feedstock, Fuel & Electricity	Central Case & H2 Generator	Central Case & Grid Electricity	Central Case & H2 Generator	Feedstock Priced at Zero	Feedstock Priced at Zero & Grid Electricity	Central Case & H2 Generator	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	Asia (Ship)	Asia (Ship)	Asia (Ship)	Asia (Ship)	Asia (Ship)	W. Europe (Ship)	Asia (Ship)

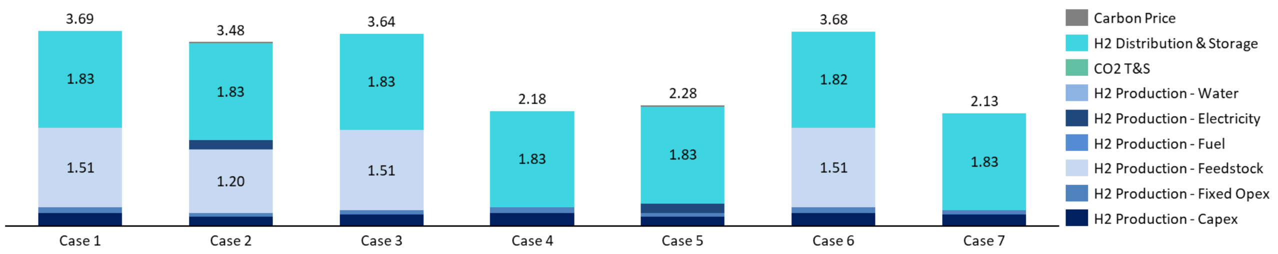

Figure 121: LCOH for HEE (TRL 4-6) in Iran in 2020 (€/kgH$_2$)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 122. As previously discussed, the feedstock price and H_2 distribution fee are the most significant cost components. However, the variation of the H_2 distribution in our sensitivity analysis does not significantly impact the LCOH due to the tighter band on the cost variation. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the oil is varied by + / - 31% and this changes the LCOH by +/- 12.8%. Variation to the Capex, fixed Opex and hydrogen distribution and storage has a cumulative impact of + / - 5.9% on the LCOH.

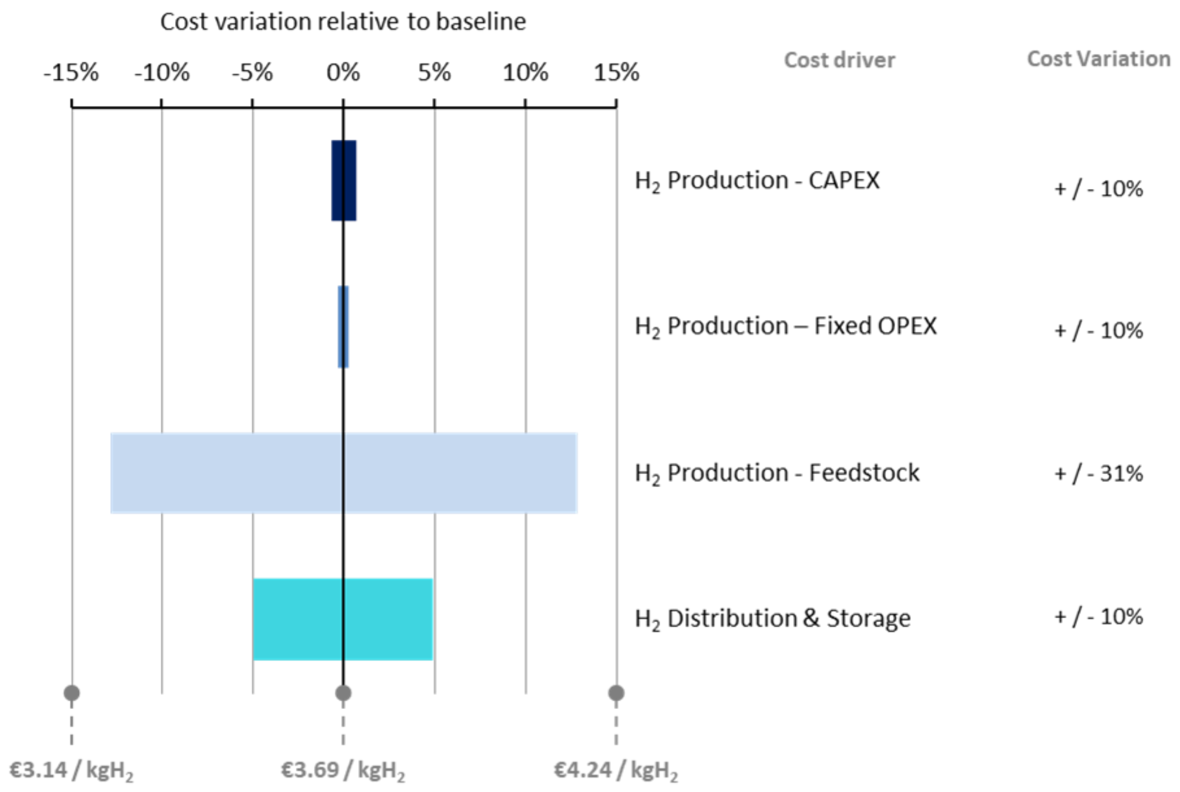

Figure 122: Levelised cost of hydrogen for HEE (TRL 4-6) in the Iran base case in 2020 (€/kgH$_2$)

Long-Term Technoeconomic Assessment (2050)

Six cases are explored for HEE in Iran from 2050. These are summarised in Table 75 with results displayed in Figure 123.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity and H_2 distribution.

Case 2 & 3 – Capex & Fixed Opex Reductions (15%) for New and Old Wells

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%.

- Since the Capex, in both cases, is comparatively small, the impact of further cost reductions is minimal. For the new well the LCOH reduction is 2.0% and for the old well the LCOH reduction is 3.1%.

Case 4 – Oil from Well is Free

- As for 2020, where the value of the oil is significantly depreciated or it cannot be extracted for commercial activities, there are significant cost reduction opportunities. In this case, the LCOH is reduced by 53.5%.

Case 5 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs, reducing the LCOH by 36.1%. This significant cost reduction is indicative of the fact that near term markets for hydrogen remain a long way from Nigeria.

Case 6 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 5 reveals a pathway to very low-cost blue hydrogen from Iran. The base case LCOH is reduced from €3.57/kgH_2 to €0.26/kgH_2; a 92.7% reduction.

Table 75: Summary of cases analysed for HEE in Iran in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Type	Baseline	Capex Reduction	Capex Reduction	Oil from Well Priced as Zero	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	New Well 5% Learning Rate	New Well 20% Learning Rate	Old Well 20% Learning Rate	New Well 5% Learning Rate	New Well 5% Learning Rate	Old Well 20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Feedstock Priced at Zero	Central Case	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	Asia (Ship)	Asia (Ship)	Asia (Ship)	Asia (Ship)	Local (Pipe)	Local (Pipe)

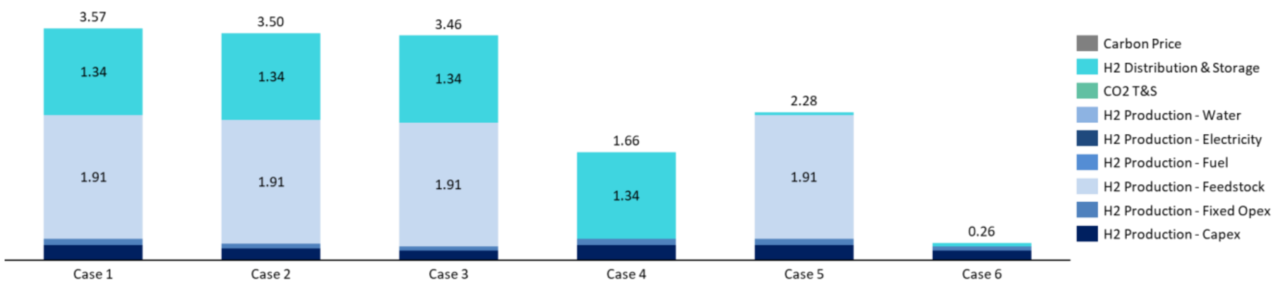

Figure 123: LCOH for HEE (TRL 4-6) in Iran in 2050 (€/kgH_2)

Iraq SNR

Deployments in the 2020s

Two cases are explored for SNR in Iraq from 2020. These are summarised in Table 102 with results displayed in Figure 124.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Alternative H_2 Distribution (W. Europe Shipping)

- Case 2 proves that Iraq could just as viably distribute hydrogen to Western Europe as opposed to Asia. The distance increase of c. 550km only increases the LCOH by 2.3%.

Table 76: Summary of cases analysed for SNR in Iraq in 2020

Sensitivity	Case 1	Case 2
Type	Baseline	Alternative H2 Distribution (Ship)
Capex & Fixed Opex	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Central Case
CO_2 Price	Central Case	Central Case
CO_2 T&S	Iraq (Pipe)	Iraq (Pipe)
H_2 Distribution	Asia (Ship)	W. Europe (Ship)

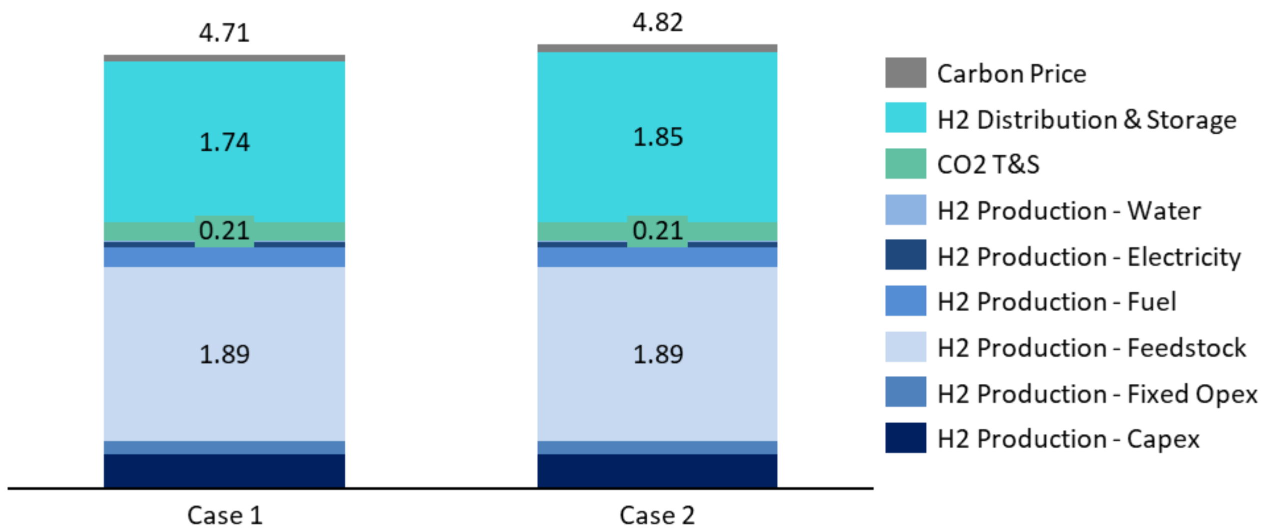

Figure 124: LCOH for SNR (TRL 9) in Iraq in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 125. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of these cost components does not significantly impact the LCOH due to the tighter band on the cost variations. In aa cases, the variation of the cost component does not change the LCOH by more than +/- 4.5%. Variation to the Capex, fixed Opex, electricity demand, water and carbon price has a cumulative impact of + / - 2.3% on the LCOH.

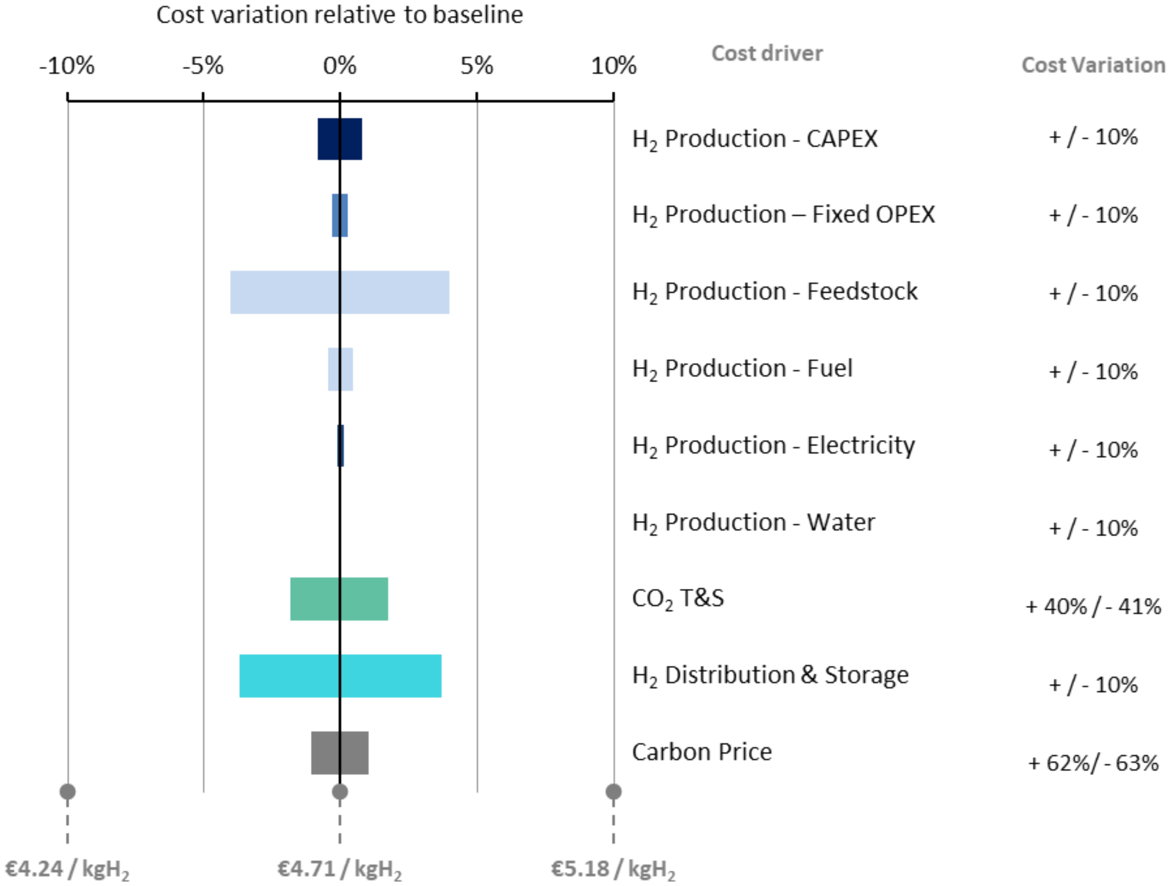

Figure 125: Levelised cost of hydrogen for SNR (TRL 9) in the Iraq base case in 2020 (€/kgH$_2$)

Long-Term Technoeconomic Assessment (2050)

Four cases are explored for SNR in Iraq from 2050. These are summarised in Table 77 with results displayed in Figure 126.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 1.7% reduction on the Base Case.

Case 3 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs and the LCOH; by up to 25.1%.

Case 4 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 and 3 reduces the base case LCOH from €4.79/kgH$_2$ to €3.51/kgH$_2$; a 26.7% reduction.
- Reductions in the LCOH for SNR are more challenging to achieve as naphtha feedstock is a refined oil product and therefore unlikely to be accessible as a waste feedstock.

Table 77: Summary of cases analysed for SNR in Iraq in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4
Type	Baseline	Capex Reduction	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Central Case
CO_2 Price	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Iraq (Pipe)	Iraq (Pipe)	Iraq (Pipe)	Iraq (Pipe)
H_2 Distribution	Asia (Ship)	Asia (Ship)	Local (Pipe)	Local (Pipe)

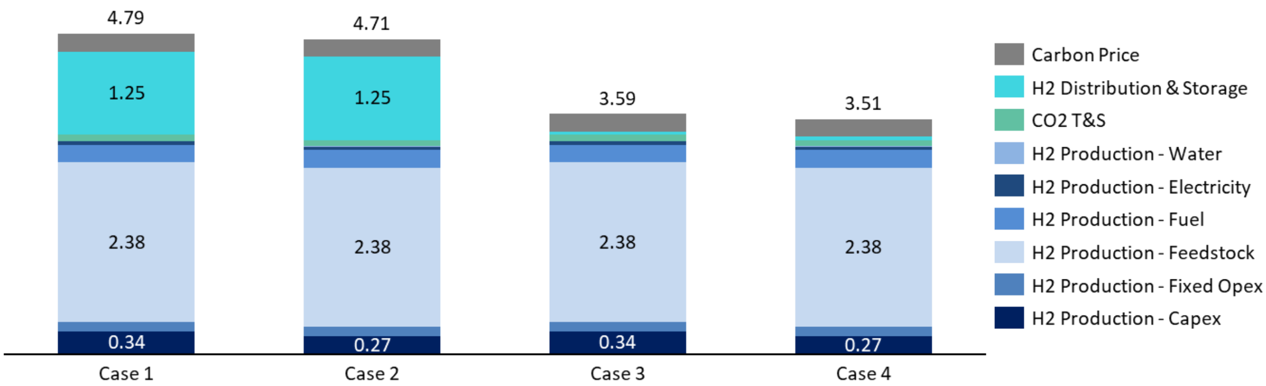

Figure 126: LCOH for SNR (TRL 9) in Iraq in 2050 (€/kgH_2)

Kuwait POX

Deployments in the 2020s

Four cases are explored for POX in Kuwait from 2020. These are summarised in Table 78 with results displayed in Figure 127.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Valuing Vacuum Residue as a Waste Product

- Case 2 demonstrates the significant impact of the price of feedstock on the LCOH.
- By valuing the vacuum residue as a waste product instead of valuing it at the price of oil, the LCOH is reduced by 29.5%.
- It is therefore important to identify sites where the value of the feedstock tends to zero and removes / reduces the size of this cost component.

Case 3 – CO_2 Shipping to Saudi Arabia

- CO_2 Shipping from Kuwait to Saudi Arabia is analysed as a sensitivity. However this involves shipping over a distance of c.450km, prior to a 300km onshore pipeline in Saudi Arabia to an onshore storage site. This increases the LCOH by 28.9%.

Case 4 – Alternative H_2 Distribution (W. Europe Shipping)

- Case 4 proves that Kuwait could just as viably distribute hydrogen to Western Europe as opposed to Asia. The distance increase of c. 550km only increases the LCOH by 0.3%.

Table 78: Summary of cases analysed for POX in Kuwait in 2020

Sensitivity	Case 1	Case 2	Case 3	Case 4
Type	Baseline	Vacuum Residue as Waste Product	Alternative CO2 T&S (Netherlands)	Alternative H2 Distribution (Ship)
Capex & Fixed Opex	Central Case	Central Case	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Feedstock = Waste Product	Central Case	Central Case
CO_2 Price	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Kuwait (Pipe)	Kuwait (Pipe)	Saudi Arabia (Ship)	Kuwait (Pipe)
H_2 Distribution	Asia (Ship)	Asia (Ship)	Asia (Ship)	W. Europe (Ship)

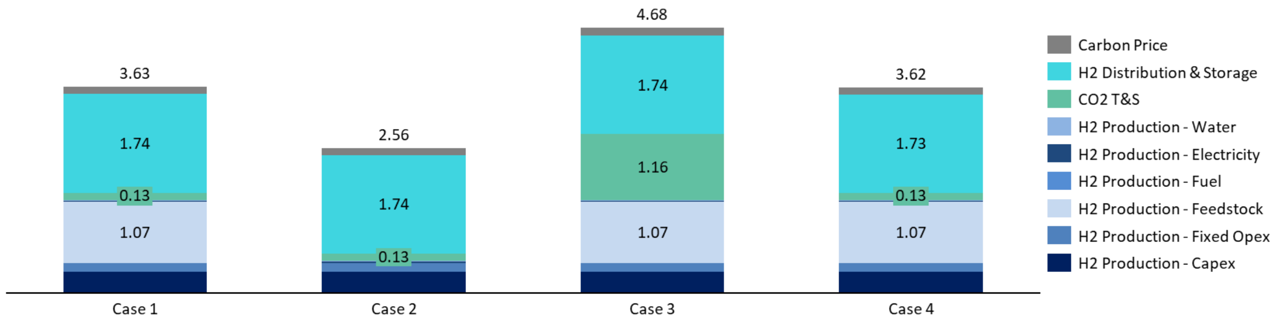

Figure 127: LCOH for POX (TRL 9) in Kuwait in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 128. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the latter of these two cost components does not significantly impact the LCOH due to the tighter band on the cost variation. In both cases, the variation of the cost component does not change the LCOH by more than +/- 5%. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the vacuum residue is varied by + / - 31%

and this changes the LCOH by +/- 9.5%. Variation to the Capex, fixed Opex, electricity demand, water and carbon price has a cumulative impact of + / - 3.7% on the LCOH.

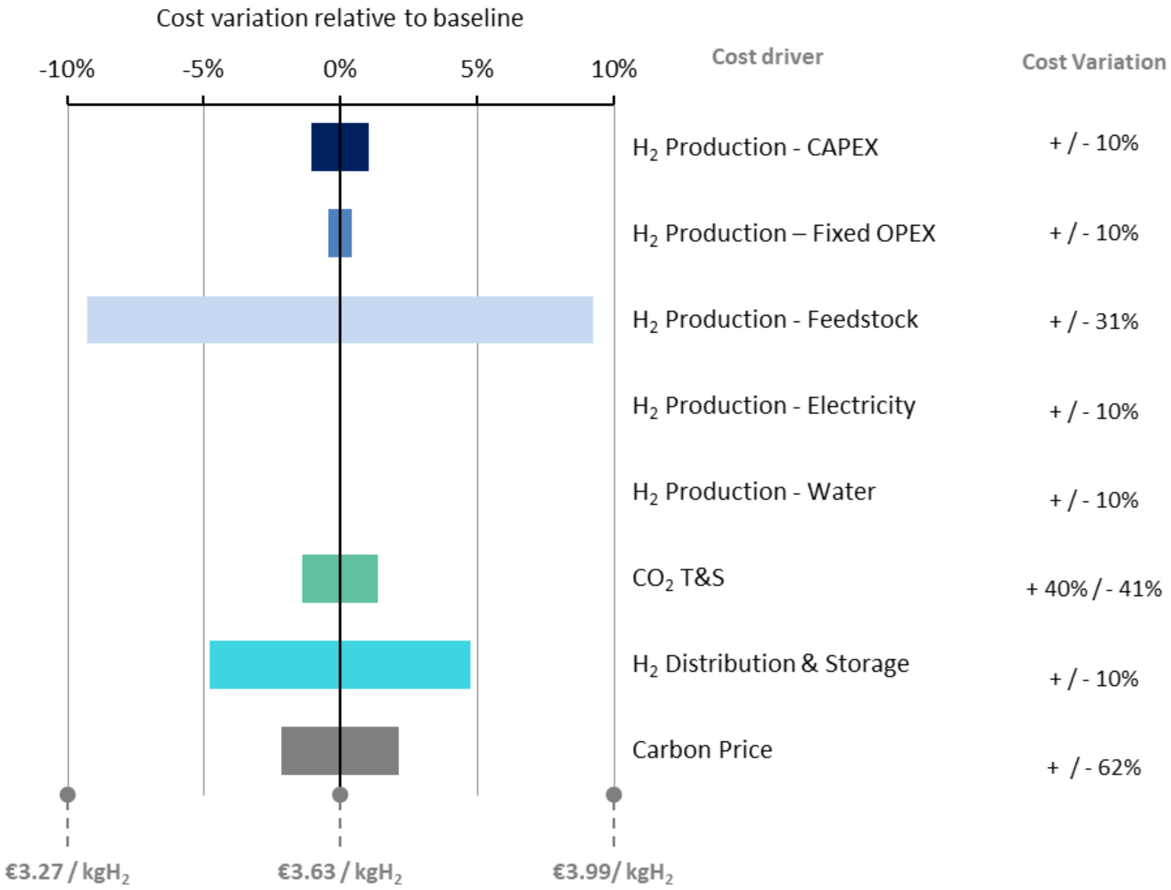

Figure 128: Levelised cost of hydrogen for POX (TRL 9) in the Kuwait base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Six cases are explored for POX in Kuwait from 2050. These are summarised in Table 79 with results displayed in Figure 129.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 2.3% reduction on the Base Case.

Case 3 – Valuing Vacuum Residue as a Waste Product

- As for 2020, valuing vacuum residue as a waste product significantly reduces the LCOH; in this case by 39.9%. It remains important to identify sites where this occurs.

Case 4 – Alternative CO_2 T&S (Saudi Arabia shipping)

- CO_2 Shipping from Kuwait to Saudi Arabia is analysed as a sensitivity. However, this involves shipping over a distance of c.450km, prior to a 300km onshore pipeline in Saudi Arabia to an onshore storage site. This increases the LCOH by 8.8%. A significant reduction from 28.9% in 2020.

Case 5 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs and the LCOH; by up to 35.2%.

Case 6 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 5 reveals a pathway to very low cost blue hydrogen from Kuwait. The base case LCOH is reduced from €3.41/kgH_2 to €0.78/kgH_2; a 77.1% reduction.

Table 79: Summary of cases analysed for POX in Kuwait in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Type	Baseline	Capex Reduction	Vacuum Residue as Waste Product	Alternative CO2 T&S (Saudi Arabia)	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	5% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Feedstock = Waste Product	Central Case	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Kuwait (Pipe)	Kuwait (Pipe)	Kuwait (Pipe)	Saudi Arabia (Ship)	Kuwait (Pipe)	Kuwait (Pipe)
H_2 Distribution	Asia (Ship)	Asia (Ship)	Asia (Ship)	Asia (Ship)	Local (Pipe)	Local (Pipe)

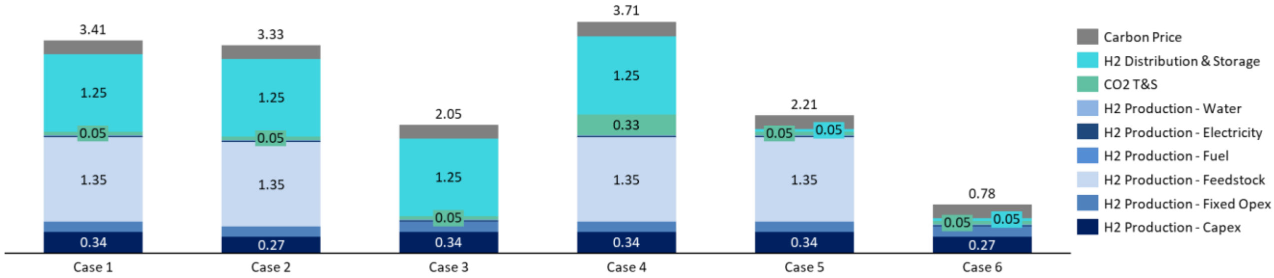

Figure 129: LCOH for POX (TRL 9) in Kuwait in 2050 (€/kgH_2)

Saudi Arabia POX

Deployments in the 2020s

Three cases are explored for POX in Saudi Arabia from 2020. These are summarised in Table 80 with results displayed in Figure 130.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Valuing Vacuum Residue as a Waste Product

- Case 2 demonstrates the significant impact of the price of feedstock on the LCOH.
- By valuing the vacuum residue as a waste product instead of valuing it at the price of oil, the LCOH is reduced by 27.1%.
- It is therefore important to identify sites where the value of the feedstock tends to zero and removes / reduces the size of this cost component.

Case 3– Alternative H_2 Distribution (W. Europe shipping)

- Case 3 proves that Saudi Arabia could just as viably distribute hydrogen to Western Europe as opposed to Asia. The distance increase of c. 500km decreases the LCOH by 0.5%. This is due to a reduced onshore H_2 pipeline distance in Western Europe.

Table 80: Summary of cases analysed for POX in Saudi Arabia in 2020

Sensitivity	Case 1	Case 2	Case 3
Type	Baseline	Vacuum Residue as Waste Product	Alternative H2 Distribution (Ship)
Capex & Fixed Opex	Central Case	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Feedstock = Waste Product	Central Case
CO_2 Price	Central Case	Central Case	Central Case
CO_2 T&S	Saudi Arabia (Pipe)	Saudi Arabia (Pipe)	Saudi Arabia (Pipe)
H_2 Distribution	Asia (Ship)	Asia (Ship)	W. Europe (Ship)

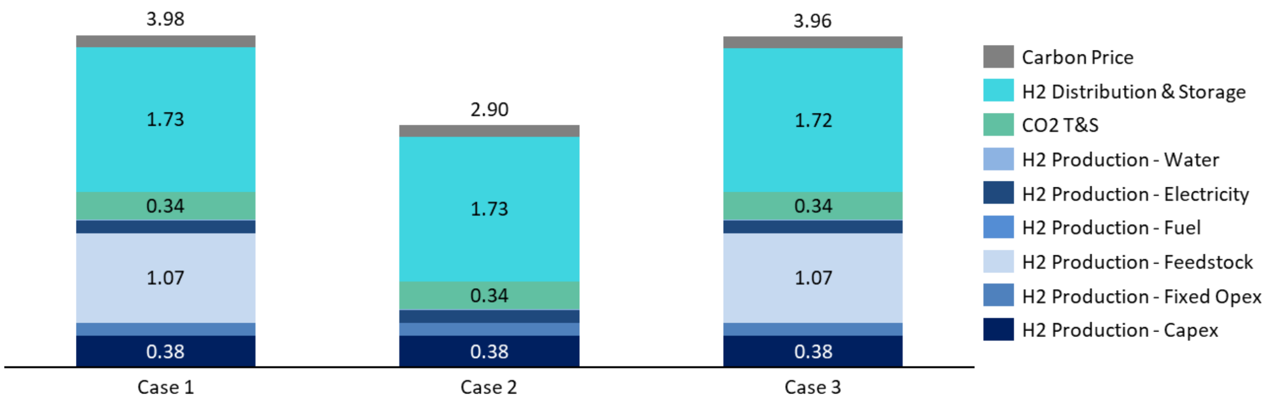

Figure 130: LCOH for POX (TRL 9) in Saudi Arabia in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 131. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the latter of these two cost components does not significantly impact the LCOH due to the tighter band on the cost variation. In both cases, the variation of the cost component does not change the LCOH by more than +/- 4.5%. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the vacuum residue is varied by + / - 31% and this changes the LCOH by +/- 8.6%. Variation to the Capex, fixed Opex, electricity demand, water and carbon price has a cumulative impact of + / - 4.0% on the LCOH.

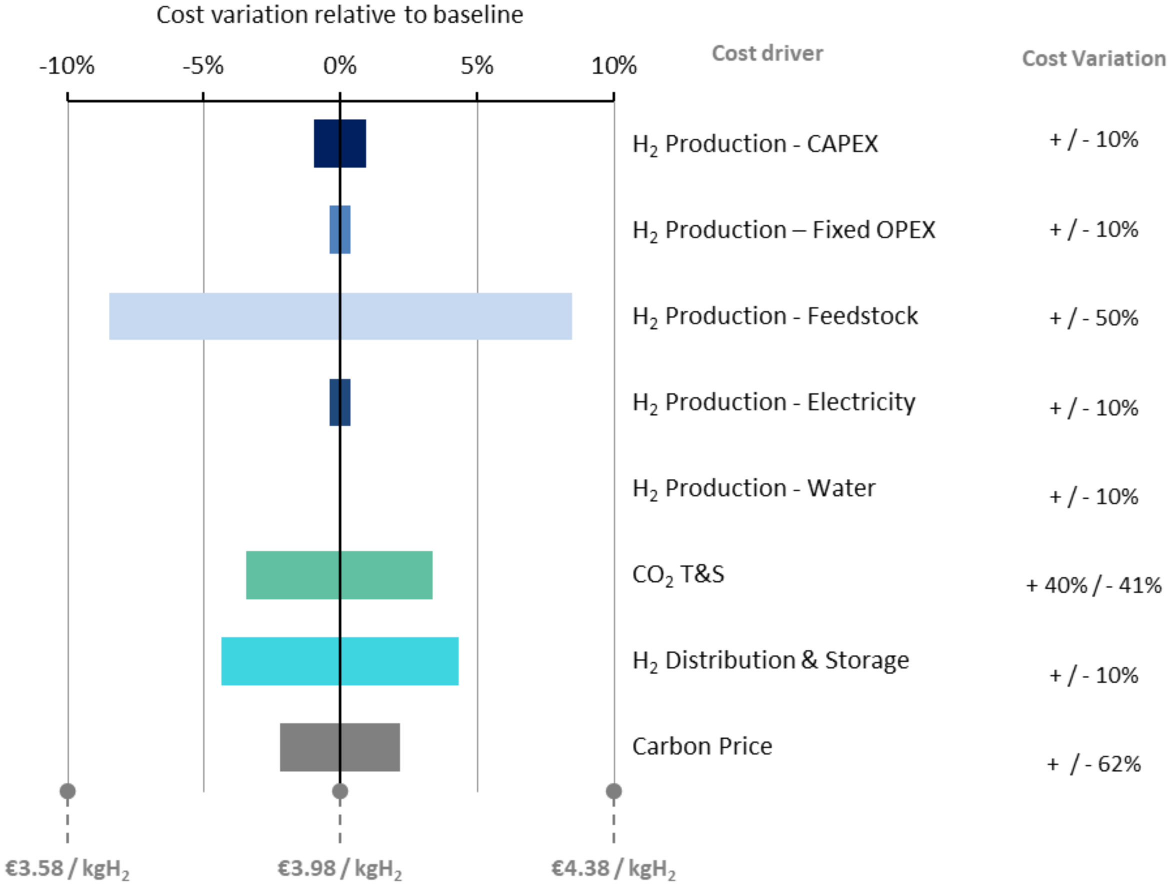

Figure 131: Levelised cost of hydrogen for POX (TRL 9) in the Saudi Arabia base case in 2020 (€/kgH2)

Long-Term Technoeconomic Assessment (2050)

Five cases are explored for POX in Saudi Arabia from 2050. These are summarised in Table 81 with results displayed in Figure 132.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 2.2% reduction on the Base Case.

Case 3 – Valuing Vacuum Residue as a Waste Product

- As for 2020, valuing vacuum residue as a waste product significantly reduces the LCOH; in this case by 37.7%. It remains important to identify sites where this occurs.

Case 4 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.

- This significantly reduces H_2 distribution costs and the LCOH; by up to 33.2%.

Case 5 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 4 reveals a pathway to very low cost blue hydrogen from Saudi Arabia. The base case LCOH is reduced from €3.61/kgH$_2$ to €0.97/kgH$_2$; a 73.1% reduction.

Table 81: Summary of cases analysed for POX in Saudi Arabia in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5
Type	Baseline	Capex Reduction	Vacuum Residue as Waste Product	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Feedstock = Waste Product	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Saudi Arabia (Pipe)	Saudi Arabia (Pipe)	Saudi Arabia (Pipe)	Saudi Arabia (Pipe)	Saudi Arabia (Pipe)
H_2 Distribution	Asia (Ship)	Asia (Ship)	Asia (Ship)	Local (Pipe)	Local (Pipe)

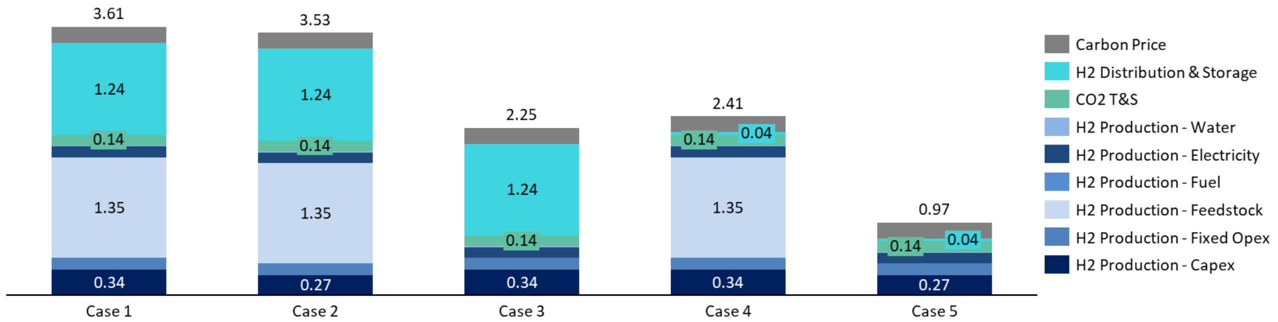

Figure 132: LCOH for POX (TRL 9) in Saudi Arabia in 2050 (€/kgH$_2$)

Nigeria HEE

Deployments in the 2020s

Eight cases are explored for HEE in Nigeria from 2020. These are summarised in Table 82 with results displayed in Figure 133.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.
- Process electricity demand is supplied by an on-site hydrogen generator.

Case 2 - Grid Electricity Supply

- Case 2 replaces the on-site hydrogen generator with electricity supplied from the grid.

Case 3 – Low Cost Well Option

- Where the technology operator can access existing infrastructure and pre-existing wells, it is possible to save upfront capital costs associated with well drilling based on Element Energy's bottom up cost analysis. Whilst the Capex is reduced by 14.4%, the overall LOCH is only reduced by 1.3%.

Case 4 – Oil from Well is Free

- In the base case, it is assumed that the technology operator has to account for the fact that oil is not sold to the market but instead converted to hydrogen.
- Where the value of this oil can be significantly depreciated or where the oil cannot be economically extracted, it can be valued as having zero cost.
- This significantly reduces the LCOH by 40.5%.

Case 5 – Oil from Well is Free & Grid Electricity

- Case 5 is the same as Case 4 with the on-site hydrogen generator replaced with electricity supplied from the grid.

Case 6 & 7 – Alternative H_2 Distribution (W. Europe Pipeline & North America Shipping)

- Case 6 assumes that new pipelines are needed to distribute hydrogen to Rotterdam. This significantly increases the LCOH by 70.5% If pipelines were instead retrofitted, the cost of hydrogen distribution could decrease by 22.5%.
- Case 7 proves that Nigeria could just as viably distribute hydrogen to North America as opposed to Western Europe. The distance increase of c. 2,800km only increases the LCOH by 2.1%.

Case 8 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 3 and 4 identifies a pathway to lower cost blue hydrogen from Nigeria. The base case LCOH is reduced from €3.73/kgH_2 to €2.17/kgH_2; a 41.8% reduction.

Table 82: Summary of cases analysed for HEE in Nigeria in 2020

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Type	Baseline	Baseline & Grid Electricity	Low Cost Well Option	Oil from Well Priced as Zero	Oil from Well Priced as Zero & Grid Electricity	Alternative H2 Distribution (Pipeline)	Alternative H2 Distribution (Ship)	Lowest Cost Pathway
Capex & Fixed Opex	New Well	New Well	Old Well	New Well	New Well	New Well	New Well	Old Well
Feedstock, Fuel & Electricity	Central Case & H2 Generator	Central Case & Grid Electricity	Central Case & H2 Generator	Feedstock Priced at Zero	Feedstock Priced at Zero & Grid Electricity	Central Case & H2 Generator	Central Case & H2 Generator	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Pipe)	N. America (Ship)	W. Europe (Ship)

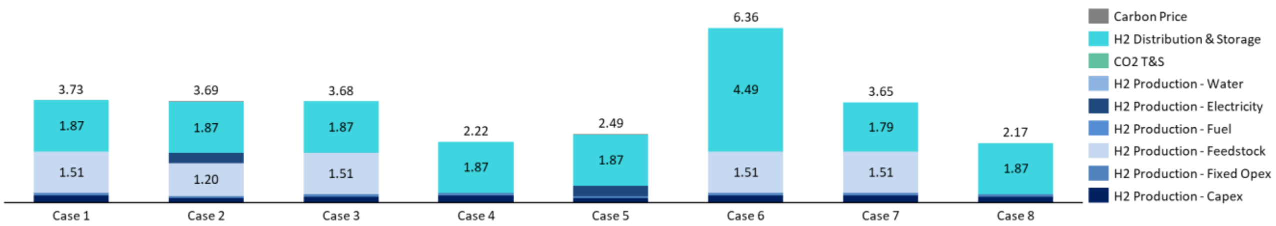

Figure 133: LCOH for HEE (TRL 4-6) in Nigeria in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 134. As previously discussed, the feedstock price and H_2 distribution fee are the most significant cost components. However, the variation of the H_2 distribution in our sensitivity analysis does not significantly impact the LCOH due to the tighter band on the cost variation. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the oil is varied by + / - 31% and this changes the LCOH by +/- 12.7%. Variation to the Capex, fixed Opex and hydrogen distribution and storage has a cumulative impact of + / - 5.9% on the LCOH.

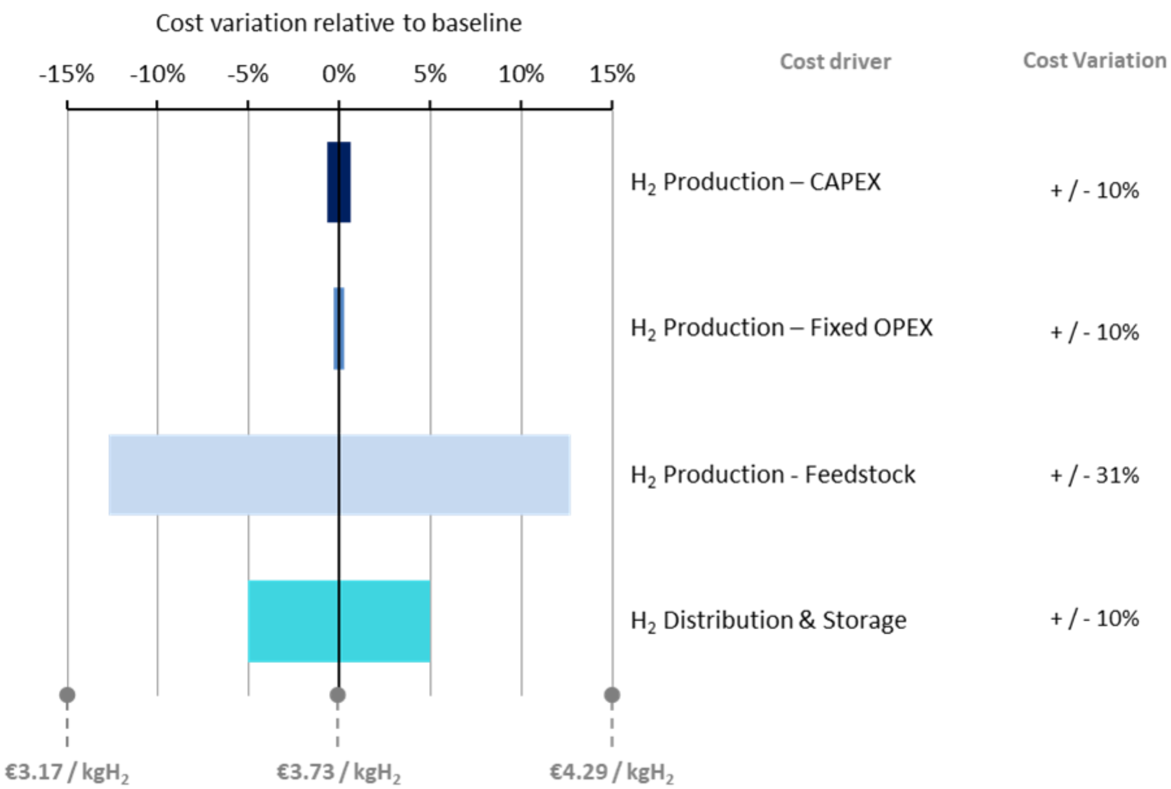

Figure 134: Levelised cost of hydrogen for HEE (TRL 4-6) in the Nigeria base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Six cases are explored for HEE in Nigeria in 2050. These are summarised in Table 83 with results displayed in Figure 135.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity and H_2 distribution.

Case 2 & 3 – Capex & Fixed Opex Reductions (15%) for New and Old Wells

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%.

- Since the Capex, in both cases, is comparatively small, the impact of further cost reductions is minimal. For the new well the LCOH reduction is 1.9% and for the old well the LCOH reduction is 3.0%.

Case 4 – Oil from Well is Free

- As for 2020, where the value of the oil is significantly depreciated or it cannot be extracted for commercial activities, there are significant cost reduction opportunities. In this case, the LCOH is reduced by 52.9%.

Case 5 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs, reducing the LCOH by 36.8%. This significant cost reduction is indicative of the fact that near term markets for hydrogen remain a long way from Nigeria.

Case 6 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 5 reveals a pathway to very low cost blue hydrogen from Nigeria. The base case LCOH is reduced from €3.61/kgH_2 to €0.26/kgH_2; a 92.8% reduction.

Table 83: Summary of cases analysed for HEE in Nigeria in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Type	Baseline	Capex Reduction	Capex Reduction	Oil from Well Priced as Zero	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	New Well 5% Learning Rate	New Well 20% Learning Rate	Old Well 20% Learning Rate	New Well 5% Learning Rate	New Well 5% Learning Rate	Old Well 20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Feedstock Priced at Zero	Central Case	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

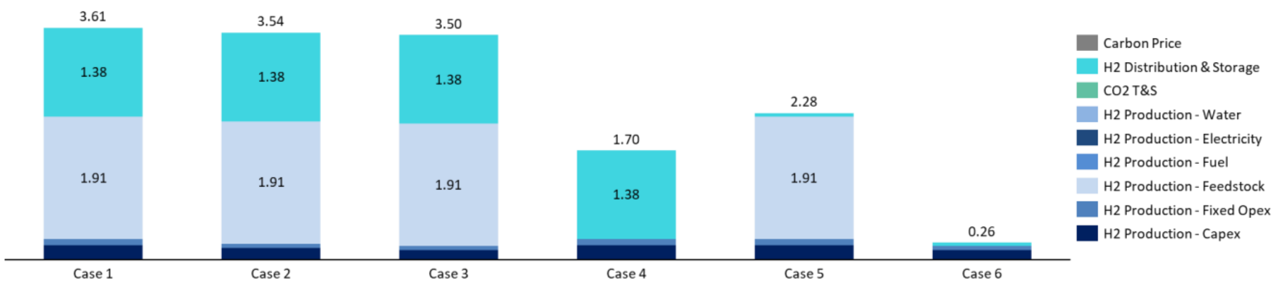

Figure 135: LCOH for HEE (TRL 4-6) in Nigeria in 2050 (€/kgH_2)

Republic of Congo POX

Deployments in the 2020s

Three cases are explored for POX in the Republic of Congo from 2020. These are summarised in Table 84 with results displayed in Figure 136.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Valuing Vacuum Residue as a Waste Product

- Case 2 demonstrates the significant impact of the price of feedstock on the LCOH.
- By valuing the vacuum residue as a waste product instead of valuing it at the price of oil, the LCOH is reduced by 25.6%.
- It is therefore important to identify sites where the value of the feedstock tends to zero and removes / reduces the size of this cost component.

Case 3 – Alternative H_2 Distribution (North America Shipping)

- Case 3 proves that the Republic of Congo could just as viably distribute hydrogen to North America as opposed to Western Europe. The distance increase of c. 1,700km only increases the LCOH by 2.8%.

Table 84: Summary of cases analysed for POX in the Republic of Congo in 2020

Sensitivity	Case 1	Case 2	Case 3
Type	Baseline	Vacuum Residue as Waste Product	Alternative H2 Distribution (Ship)
Capex & Fixed Opex	Central Case	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Feedstock = Waste Product	Central Case
CO_2 Price	Central Case	Central Case	Central Case
CO_2 T&S	Republic of Congo (Pipe)	Republic of Congo (Pipe)	Republic of Congo (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	N. America (Ship)

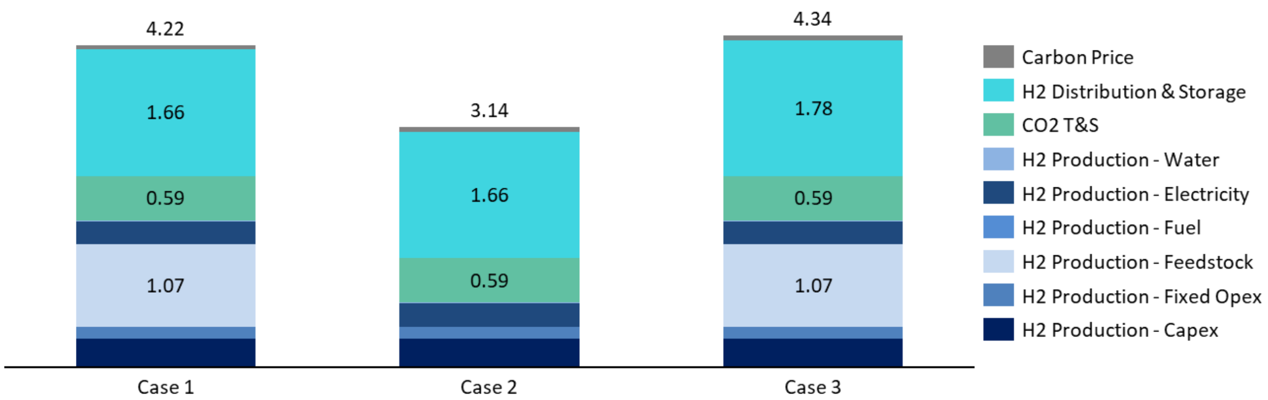

Figure 136: LCOH for POX (TRL 9) in the Republic of Congo in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 137. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the latter of these two cost components does not significantly impact the LCOH due to the tighter band on the cost variation. In both cases, the variation of the cost component does not change the LCOH by more than +/- 6%. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the vacuum residue is varied by + / - 31%

and this changes the LCOH by +/- 8.0%. Variation to the Capex, fixed Opex, electricity demand, water and carbon price has a cumulative impact of + / - 2.9% on the LCOH.

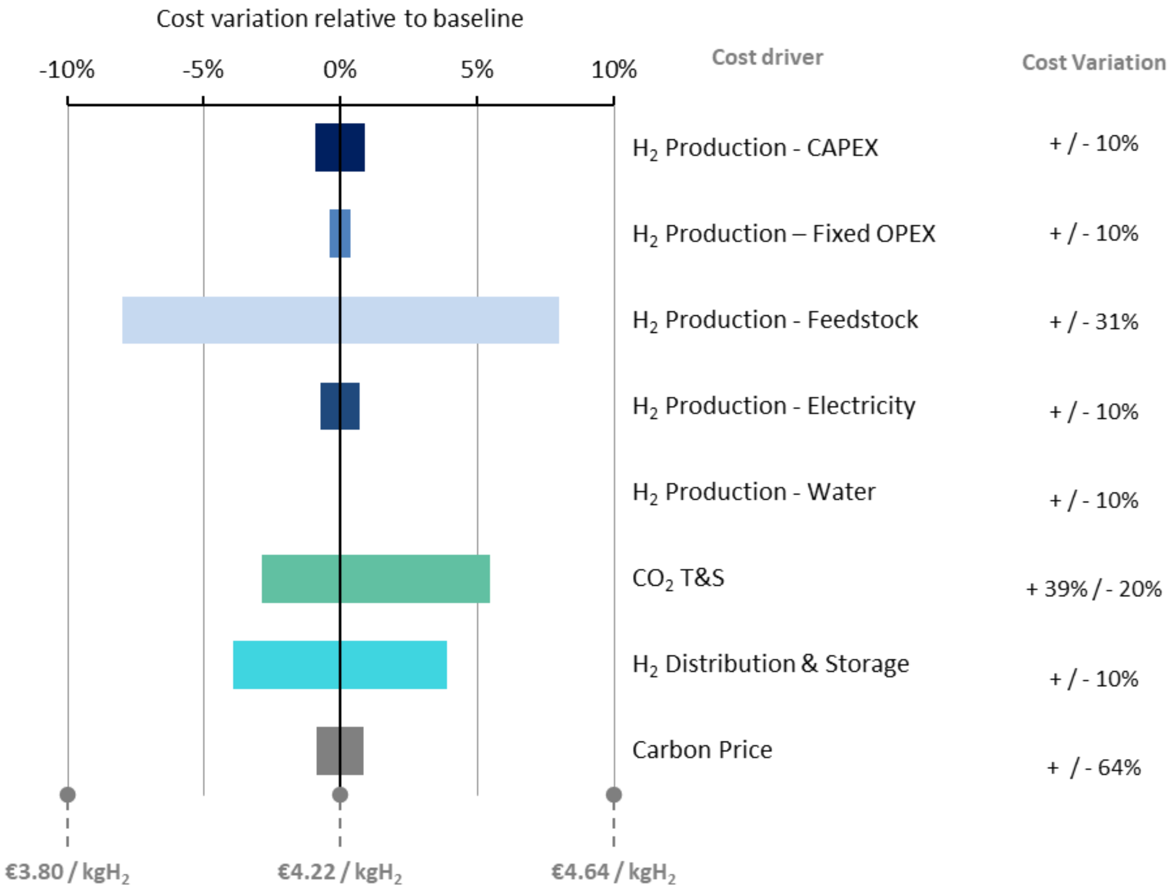

Figure 137: LCOH for POX (TRL 9) in the Republic of Congo base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Five cases are explored for POX in the Republic of Congo from 2050. These are summarised in Table 85 with results displayed in Figure 138.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 2.2% reduction on the Base Case.

Case 3 – Valuing Vacuum Residue as a Waste Product

- As for 2020, valuing vacuum residue as a waste product significantly reduces the LCOH; in this case by 38.0%. It remains important to identify sites where this occurs.

Case 4 – Local Hydrogen Demand

- As explored in Task 2 of this study, increased local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs and the LCOH; by up to 31.3%.

Case 5 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 4 reveals a pathway to very low cost blue hydrogen from the Republic of Congo. The base case LCOH is reduced from €3.58/kgH_2 to €1.03/kgH_2; a 71.2% reduction.

Table 85: Summary of cases analysed for POX in the Republic of Congo in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5
Type	Baseline	Capex Reduction	Vacuum Residue as Waste Product	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Feedstock = Waste Product	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Republic of Congo (Pipe)	Republic of Congo (Pipe)	Republic of Congo (Pipe)	Republic of Congo (Pipe)	Republic of Congo (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

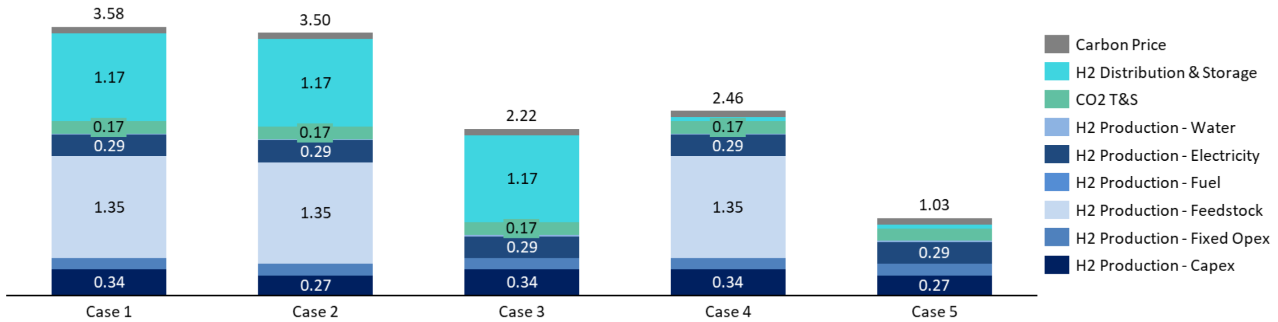

Figure 138: LCOH for POX (TRL 9) in the Republic of Congo in 2050 (€/kgH_2)

Equatorial Guinea HEE

Deployments in the 2020s

Seven cases are explored for HEE in Equatorial Guinea from 2020. These are summarised in Table 86 with results displayed in Figure 139.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.
- Process electricity demand is supplied by an on-site hydrogen generator.

Case 2 - Grid Electricity Supply

- Case 2 replaces the on-site hydrogen generator with electricity supplied from the grid.

Case 3 – Low Cost Well Option

- Where the technology operator can access existing infrastructure and pre-existing wells, it is possible to save upfront capital costs associated with well drilling based on Element Energy's bottom up cost analysis. Whilst the Capex is reduced by 14.4%, the overall LOCH is only reduced by 1.4%.

Case 4 – Oil from Well is Free

- In the base case, it is assumed that the technology operator has to account for the fact that oil is not sold to the market but instead converted to hydrogen.
- Where the value of this oil can be significantly depreciated or where the oil cannot be economically extracted, it can be valued as having zero cost.
- This significantly reduces the LCOH by 42.8%.

Case 5 – Oil from Well is Free & Grid Electricity

- Case 5 is the same as Case 4 with the on-site hydrogen generator replaced with electricity supplied from the grid.

Case 6 – Alternative H_2 Distribution (North America Shipping)

- Case 6 proves that Equatorial Guinea could just as viably distribute hydrogen to North America as opposed to Western Europe. The distance increase of c. 1,600km only increases the LCOH by 3.1%.

Case 7 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 3 and 4 identifies a pathway to lower cost blue hydrogen from Equatorial Guinea. The base case LCOH is reduced from €3.53/kgH_2 to €1.97/kgH_2; a 44.2% reduction.

Table 86: Summary of cases analysed for HEE in Equatorial Guinea in 2020

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Type	Baseline	Baseline & Grid Electricity	Low Cost Well Option	Oil from Well Priced as Zero	Oil from Well Priced as Zero & Grid Electricity	Alternative H2 Distribution (Ship)	Lowest Cost Pathway
Capex & Fixed Opex	New Well	New Well	Old Well	New Well	New Well	New Well	Old Well
Feedstock, Fuel & Electricity	Central Case & H2 Generator	Central Case & Grid Electricity	Central Case & H2 Generator	Feedstock Priced at Zero	Feedstock Priced at Zero & Grid Electricity	Central Case & H2 Generator	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	N. America (Ship)	W. Europe (Ship)

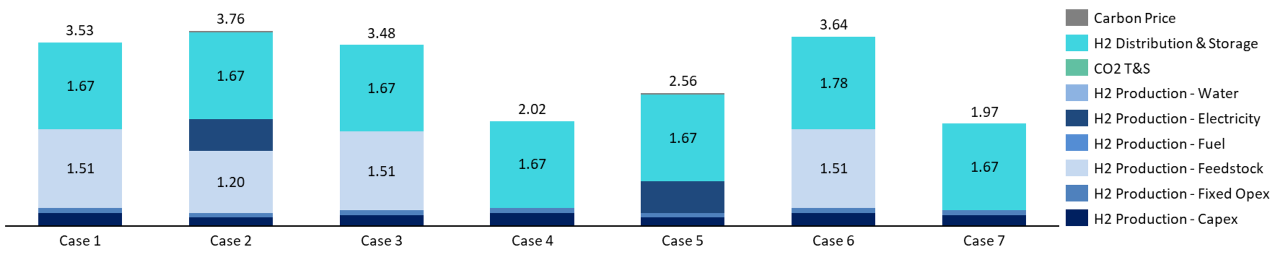

Figure 139: LCOH for HEE (TRL 4-6) in Equatorial Guinea in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 140. As previously discussed, the feedstock price and H_2 distribution fee are the most significant cost components. However, the variation of the H_2 distribution in our sensitivity analysis does not significantly impact the LCOH due to the tighter band on the cost variation. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the oil is varied by + / - 31% and this changes the LCOH by +/- 13.4%. Variation to the Capex, fixed Opex and hydrogen distribution and storage has a cumulative impact of + / - 5.7% on the LCOH.

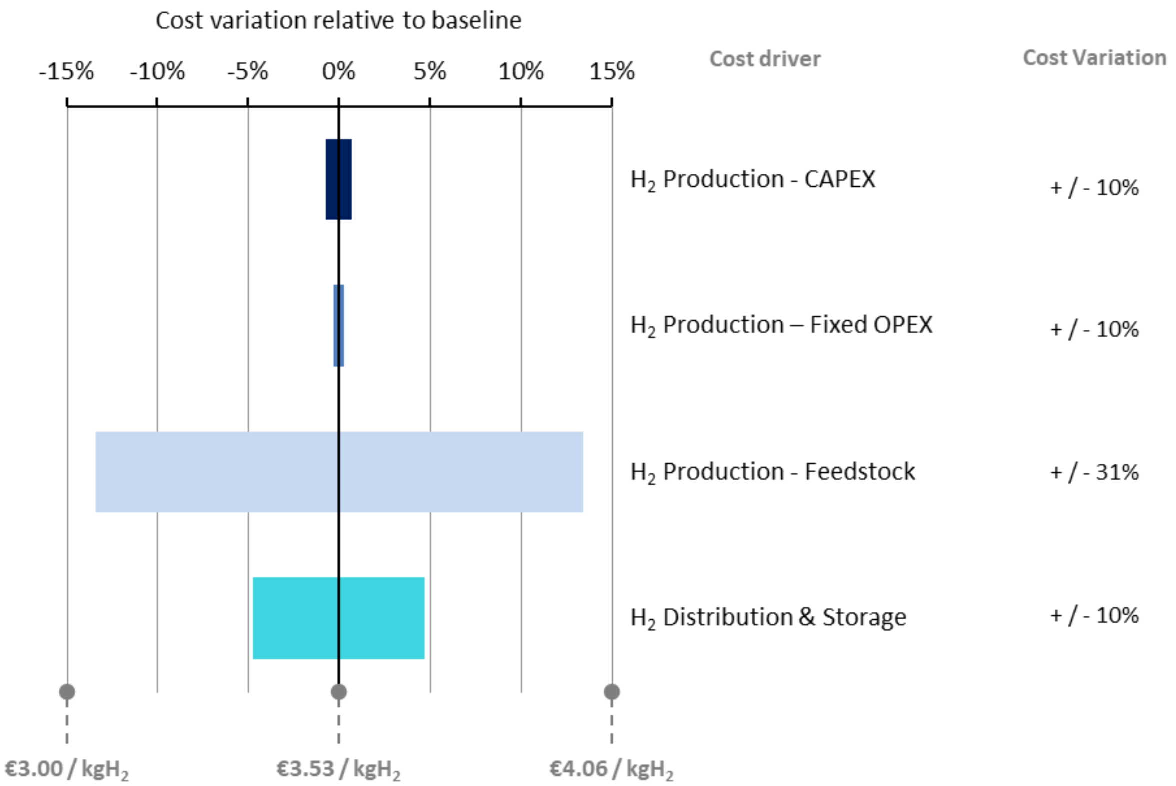

Figure 140: LCOH for HEE (TRL 4-6) in the Equatorial Guinea base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Six cases are explored for HEE in Equatorial Guinea from 2050. These are summarised in Table 87 with results displayed in Figure 141.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity and H_2 distribution.

Case 2 & 3 – Capex & Fixed Opex Reductions (15%) for New and Old Wells

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%.

- Since the Capex, in both cases, is comparatively small, the impact of further cost reductions is minimal. For the new well the LCOH reduction is 2.1% and for the old well the LCOH reduction is 3.2%.

Case 4 – Oil from Well is Free

- As for 2020, where the value of the oil is significantly depreciated or it cannot be extracted for commercial activities, there are significant cost reduction opportunities. In this case, the LCOH is reduced by 56.0%.

Case 5 – Local Hydrogen Demand

- As explored in Task 2 of this study, increased local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs, reducing the LCOH by 33.4%. This significant cost reduction is indicative of the fact that near term markets for hydrogen remain a long way from Equatorial Guinea.

Case 6 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 5 reveals a pathway to very low cost blue hydrogen from Equatorial Guinea. The base case LCOH is reduced from €3.41/kgH_2 to €0.25/kgH_2; a 92.7% reduction.

Table 87: Summary of cases analysed for HEE in Equatorial Guinea in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Type	Baseline	Capex Reduction	Capex Reduction	Oil from Well Priced as Zero	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	New Well 5% Learning Rate	New Well 20% Learning Rate	Old Well 20% Learning Rate	New Well 5% Learning Rate	New Well 5% Learning Rate	Old Well 20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Feedstock Priced at Zero	Central Case	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

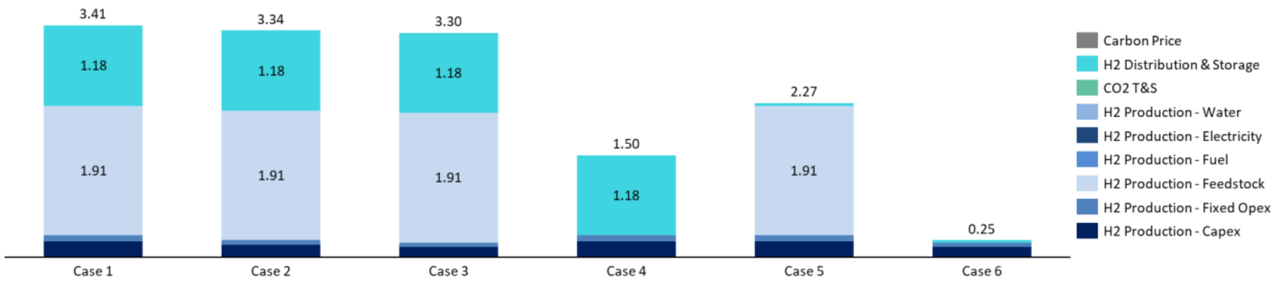

Figure 141: LCOH for HEE (TRL 4-6) in Equatorial Guinea in 2050 (€/kgH_2)

Gabon POX

Deployments in the 2020s

Three cases are explored for POX in the Republic of Congo from 2020. These are summarised in Table 88 with results displayed in Figure 142.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Valuing Vacuum Residue as a Waste Product

- Case 2 demonstrates the significant impact of the price of feedstock on the LCOH.
- By valuing the vacuum residue as a waste product instead of valuing it at the price of oil, the LCOH is reduced by 24.1%.
- It is therefore important to identify sites where the value of the feedstock tends to zero and removes / reduces the size of this cost component.

Case 3 – Alternative H_2 Distribution (North America Shipping)

- Case 3 proves that Gabon could just as viably distribute hydrogen to North America as opposed to Western Europe. The distance increase of c. 1,600km only increases the LCOH by 2.9%.

Table 88: Summary of cases analysed for POX in Gabon in 2020

Sensitivity	Case 1	Case 2	Case 3
Type	Baseline	Vacuum Residue as Waste Product	Alternative H2 Distribution (Ship)
Capex & Fixed Opex	Central Case	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Feedstock = Waste Product	Central Case
CO_2 Price	Central Case	Central Case	Central Case
CO_2 T&S	Gabon (Pipe)	Gabon (Pipe)	Gabon (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	N. America (Ship)

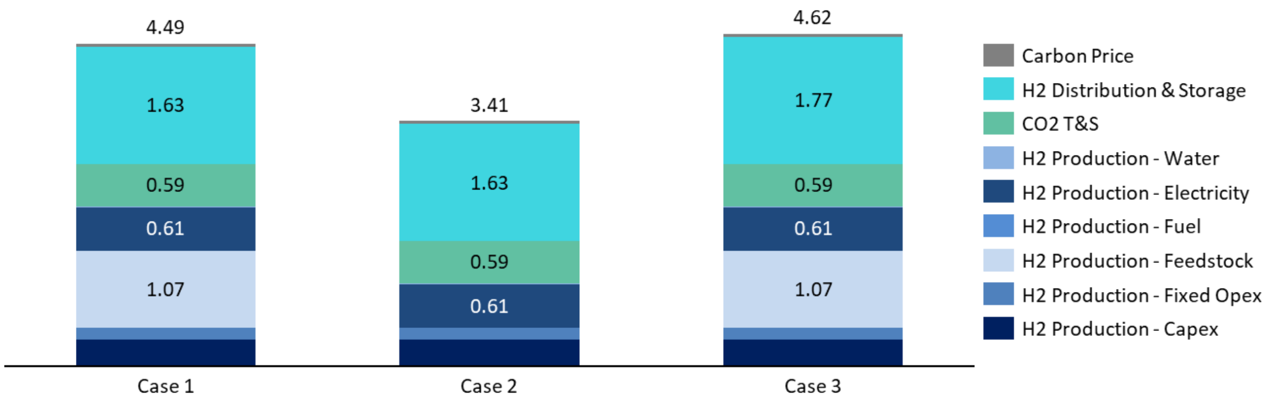

Figure 142: LCOH for POX (TRL 9) in Gabon in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 143. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the latter of these two cost components does not significantly impact the LCOH due to the tighter band on the cost variation. In both cases, the variation of the cost component does not change the LCOH by more than +/- 6%. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the vacuum residue is varied by + / - 31%

and this changes the LCOH by +/- 7.5%. Variation to the Capex, fixed Opex, electricity demand, water and carbon price has a cumulative impact of + / - 3.2% on the LCOH.

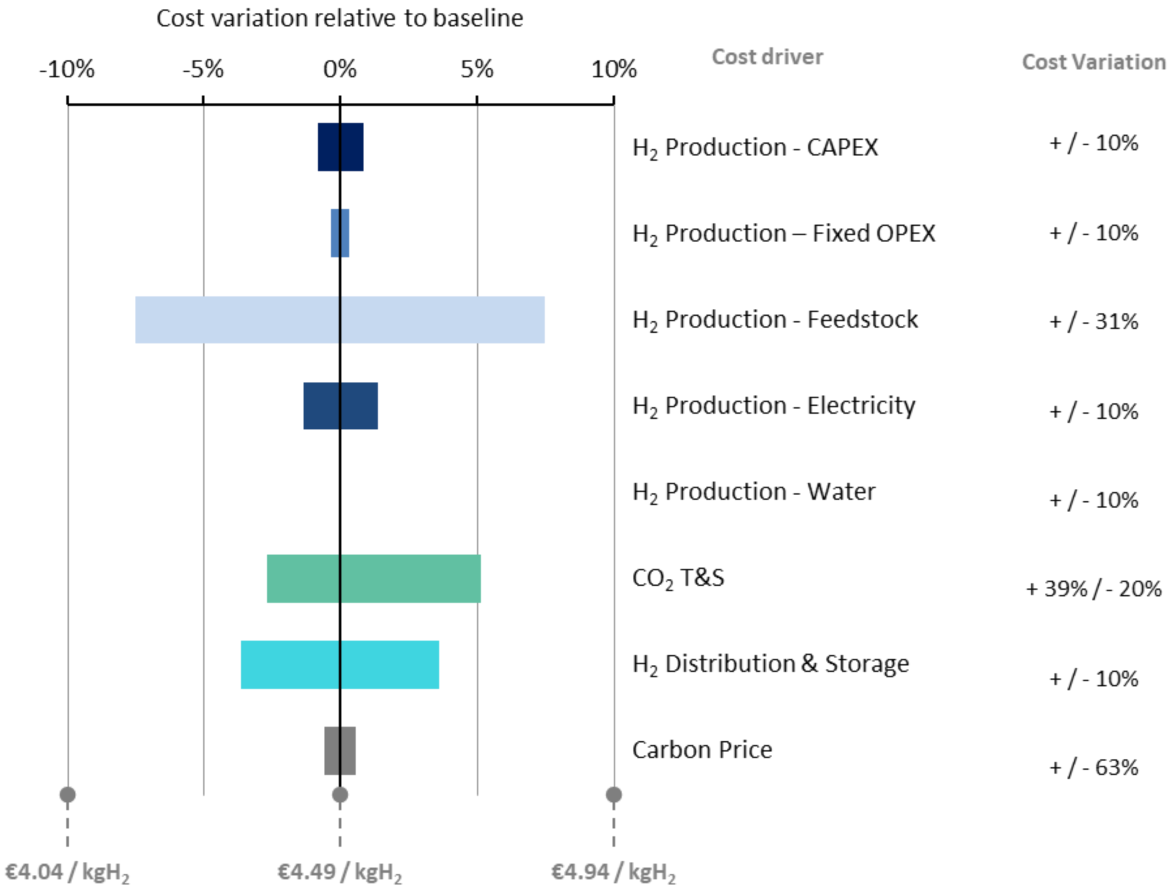

Figure 143: LCOH for POX (TRL 9) in the Gabon base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Five cases are explored for POX in Gabon from 2050. These are summarised in Table 89 with results displayed in Figure 144.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 1.8% reduction on the Base Case.

Case 3 – Valuing Vacuum Residue as a Waste Product

- As for 2020, valuing vacuum residue as a waste product significantly reduces the LCOH; in this case by 35.1%. It remains important to identify sites where this occurs.

Case 4 – Local Hydrogen Demand

- As explored in Task 2 of this study, increased local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs and the LCOH; by up to 28.3%.

Case 5 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 4 reveals a pathway to very low cost blue hydrogen from Gabon. The base case LCOH is reduced from €3.85/kgH_2 to €1.33/kgH_2; a 65.5% reduction.

Table 89: Summary of cases analysed for POX in Gabon in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5
Type	Baseline	Capex Reduction	Vacuum Residue as Waste Product	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Feedstock = Waste Product	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Gabon (Pipe)	Gabon (Pipe)	Gabon (Pipe)	Gabon (Pipe)	Gabon (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

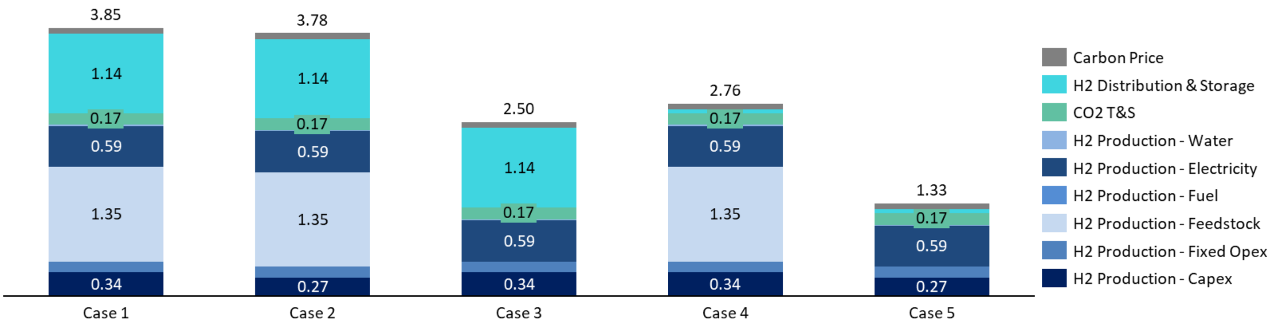

Figure 144: LCOH for POX (TRL 9) in Gabon in 2050 (€/kgH_2)

Angola SNR

Deployments in the 2020s

Three cases are explored for SNR in Angola from 2020. These are summarised in Table 90 with results displayed in Figure 145.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – CO_2 Shipping to the Netherlands

- CO_2 Shipping from Angola to the Netherlands is analysed as a sensitivity. This analysis is only done for Angola, however is likely to be an accurate representation of the CO_2 shipping costs from all West African countries.
- CO_2 shipping from West Africa could be explored further as a potential enabler for blue hydrogen projects in the region while local CO_2 T&S infrastructure is developed.
- Shipping CO_2 to the Netherlands over a distance of c.9,200km increases the LCOH by 14.5%.

Case 3 – Alternative H_2 Distribution (North America Shipping)

- Case 3 proves that Angola could just as viably distribute hydrogen to North America as opposed to Western Europe. The distance increase of c. 1,600km only increases the LCOH by 2.3%.

Table 90: Summary of cases analysed for SNR in Angola in 2020

Sensitivity	Case 1	Case 2	Case 3
Type	Baseline	Alternative CO2 T&S (Netherlands)	Alternative H2 Distribution (Ship)
Capex & Fixed Opex	Central Case	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case
CO_2 Price	Central Case	Central Case	Central Case
CO_2 T&S	Angola (Pipe)	Netherlands (Ship)	Angola (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	N. America (Ship)

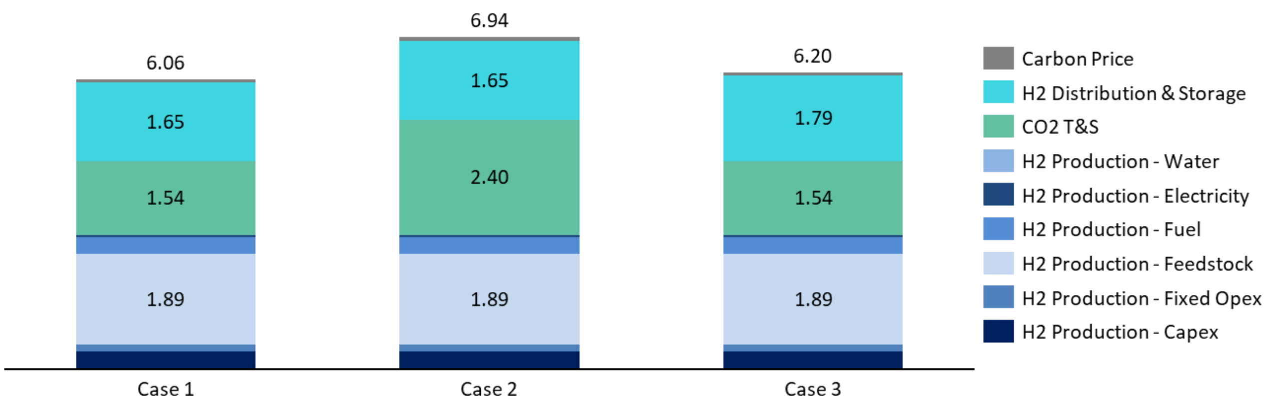

Figure 145: LCOH for SNR (TRL 9) in Angola in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 146. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the feedstock price and H2 distribution fee cost components does not significantly impact the LCOH due to the tighter band on the cost variation. In both cases, the variation of the cost component does not change the LCOH by more than +/- 3.5%. The most significant variation comes from the CO_2 T&S fee. This is varied by + 39%/ - 20% and this changes the LCOH by + 10.0% /- 5.2%. Variation to the Capex, fixed Opex, electricity demand, water and carbon price has a cumulative impact of + / - 1.6% on the LCOH.

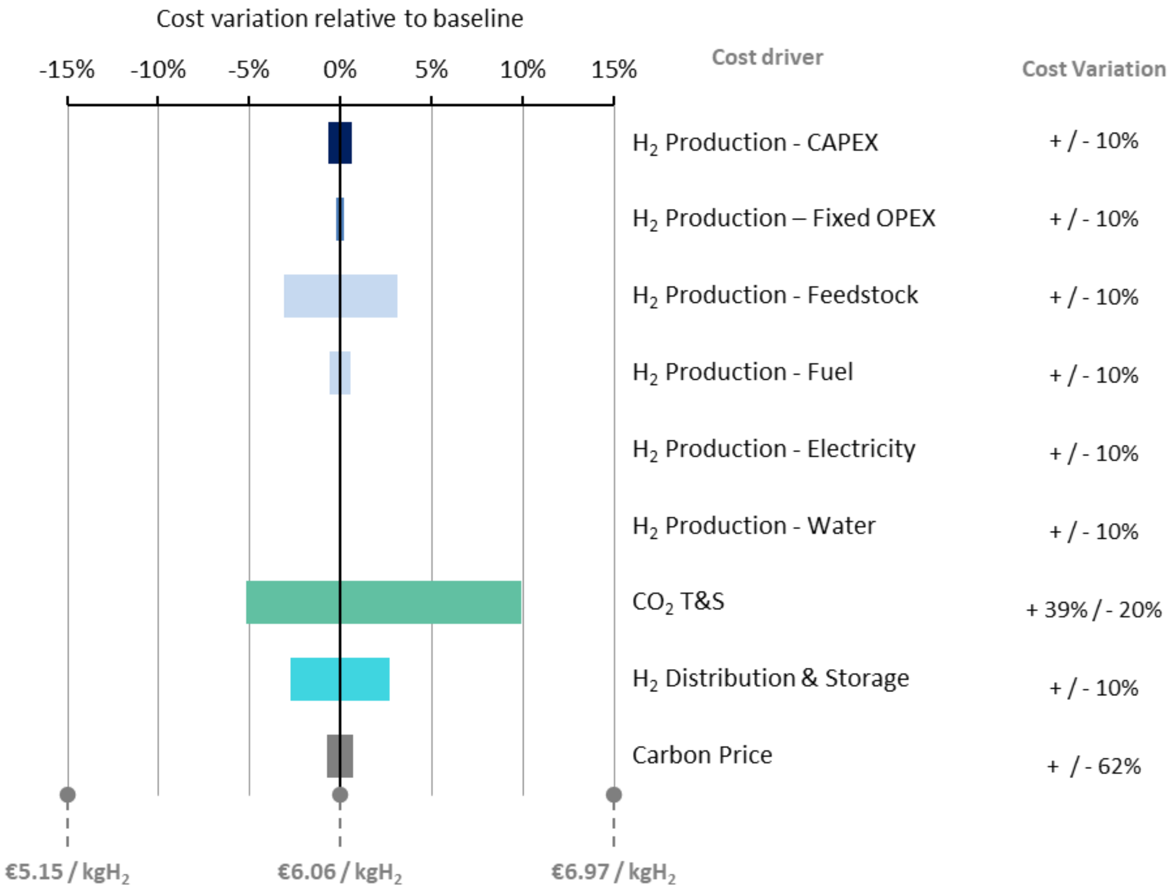

Figure 146: LCOH for SNR (TRL 9) in the Angola base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Five cases are explored for SNR in Angola from 2050. These are summarised in Table 91 with results displayed in Figure 147.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 1.6% reduction on the Base Case.

Case 3 – Alternative CO_2 T&S (Netherlands)

- CO_2 Shipping from Angola to the Netherlands is analysed as a sensitivity. Although this involves shipping over a distance of c.9,200km the LCOH is increased by 5.1%. This is a significant reduction from 14.5% in 2020.

Case 4 – Local Hydrogen Demand

- As explored in Task 2 of this study, increased local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs and the LCOH; by up to 22.0%.

Case 5 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 4 reduces the base case LCOH from €5.05/kgH_2 to €3.86/kgH_2; a 23.6% reduction.
- Reductions in the LCOH for SNR are more challenging to achieve as naphtha feedstock is a refined oil product and therefore unlikely to be accessible as a waste feedstock.

Table 91: Summary of cases analysed for SNR in Angola in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5
Type	Baseline	Capex Reduction	Alternative CO2 T&S (Netherlands)	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Angola (Pipe)	Angola (Pipe)	Netherlands (Ship)	Angola (Pipe)	Angola (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

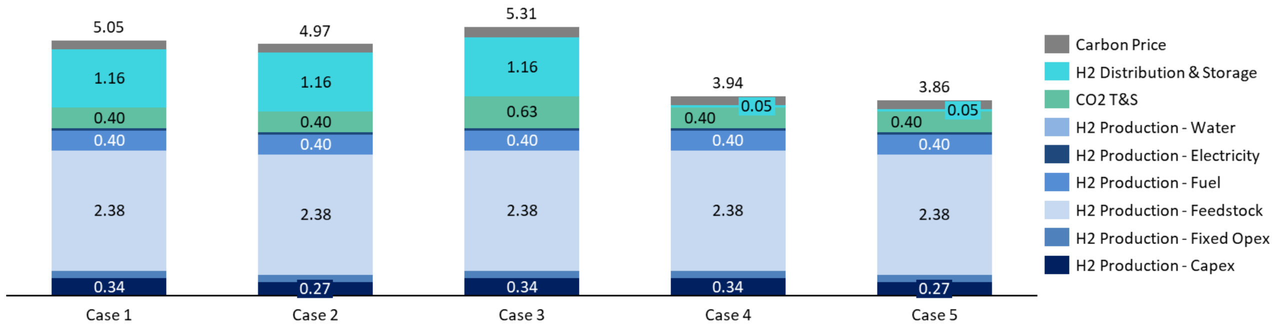

Figure 147: LCOH for SNR (TRL 9) in Angola in 2050 (€/kgH_2)

Algeria POX

Deployments in the 2020s

Six cases are explored for POX in Algeria from 2020. These are summarised in Table 92 with results displayed in Figure 148.

Table 92: Summary of cases analysed for POX in Algeria in 2020

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Type	Baseline	Vacuum Residue as Waste Product	Alternative CO2 T&S (Netherlands)	Alternative H2 Distribution (Pipeline)	Alternative H2 Distribution (Ship)	Lowest Cost Pathway
Capex & Fixed Opex	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Feedstock = Waste Product	Central Case	Central Case	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Algeria (Pipe)	Algeria (Pipe)	Netherlands (Ship)	Algeria (Pipe)	Algeria (Pipe)	Netherlands (Ship)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Pipe)	N. America (Ship)	W. Europe (Ship)

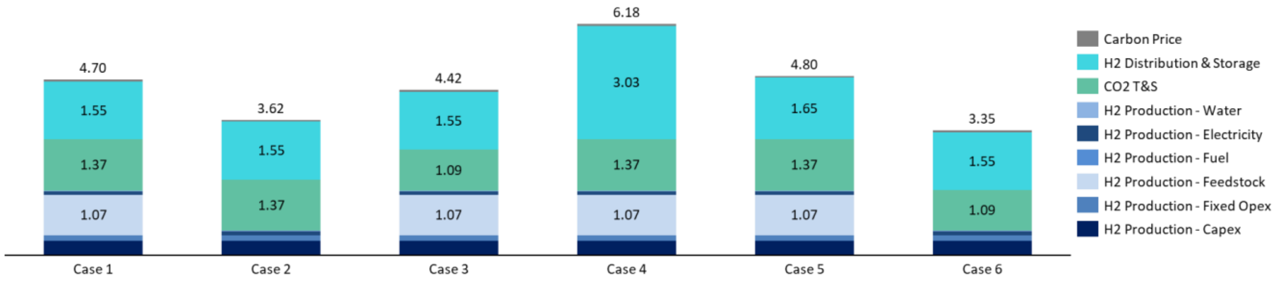

Figure 148: LCOH for POX (TRL 9) in Algeria in 2020 (€/kgH_2)

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Valuing Vacuum Residue as a Waste Product

- Case 2 demonstrates the significant impact of the price of feedstock on the LCOH.
- By valuing the vacuum residue as a waste product instead of valuing it at the price of oil, the LCOH is reduced by 23.0%.
- It is therefore important to identify sites where the value of the feedstock tends to zero and removes / reduces the size of this cost component.

Case 3 – Alternative CO_2 T&S (Netherlands)

- By assuming that the CO_2 T&S infrastructure is only used by the hydrogen production facility, shipping is more economically favourable than pipelines. This reduces the LCOH by 6.0%.
- This is because shipping favours lower throughputs over longer distances. Were this facility to be part of a larger cluster, the economics may change and a pipeline could be more economically favourable.

Case 4 & 5 – Alternative H_2 Distribution (W. Europe Pipeline & North America Shipping)

- Case 4 assumes that new pipelines are needed to distribute hydrogen to Rotterdam. This increases the LCOH by 31.5% If pipelines were instead retrofitted, the cost of hydrogen distribution could decrease by 7.4%.
- Case 5 proves that Algeria could just as viably distribute hydrogen to North America as opposed to Western Europe. The distance increase of c. 500km only increases the LCOH by 2.1%.

Case 6 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 and Case 3 identifies a pathway to lower cost blue hydrogen from Algeria. The base case LCOH is reduced from €4.70/kgH_2 to €3.35/kgH_2; a 28.8% reduction.

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 149. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the feedstock price and H_2 distribution fee does not significantly impact the LCOH due to the tighter band on the cost variation. In both cases, the variation of the cost component does not change the LCOH by more than +/- 8%. The most significant variation comes from the CO_2 T&S fee due to the wide range. The CO_2 T&S fee is varied by + 41% / - 40% and this changes the LCOH by + 11.6% /- 11.9%. Variation to the Capex, fixed Opex, electricity demand and carbon price has a cumulative impact of + / - 2.0% on the LCOH.

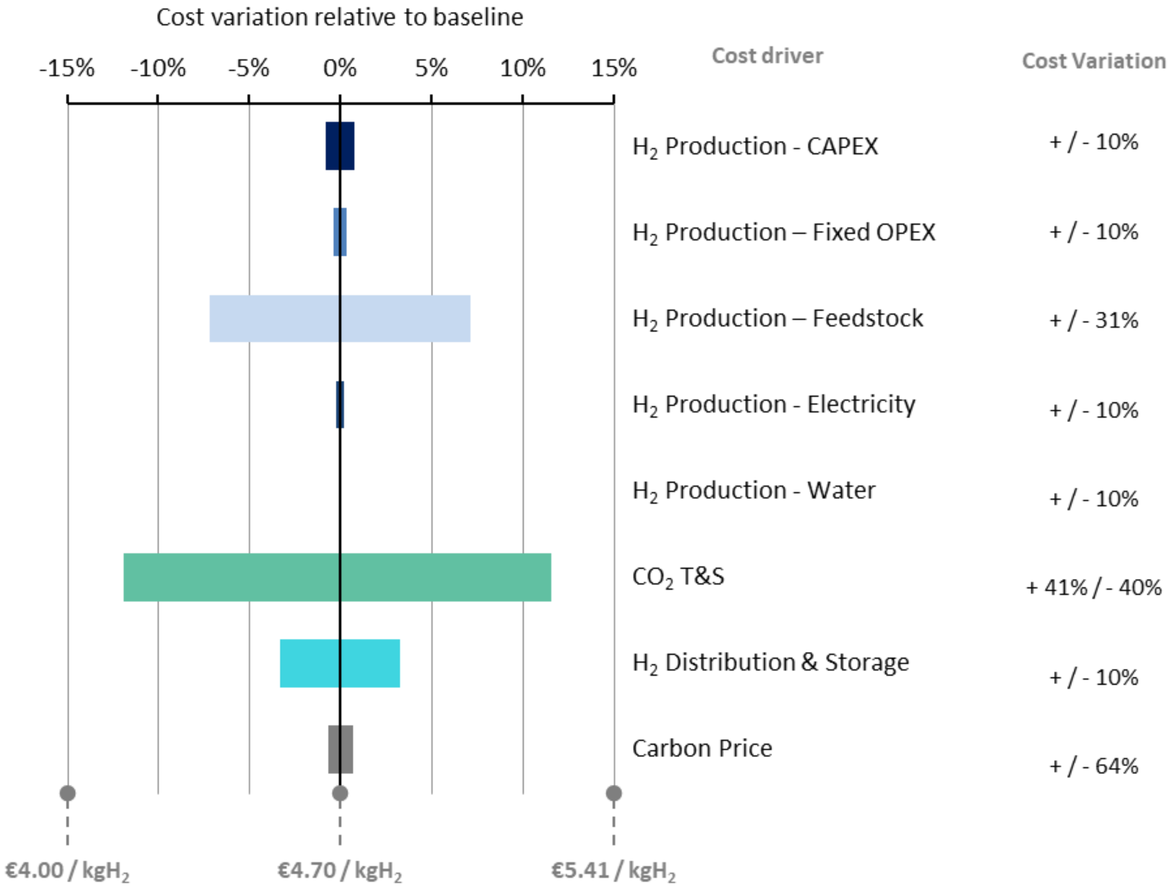

Figure 149: LCOH for POX (TRL 9) in the Algeria base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Six cases are explored for POX in Algeria in 2050. These are summarised in Table 93 with results displayed in Figure 150.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 2.2% reduction on the Base Case.

Case 3 – Valuing Vacuum Residue as a Waste Product

- As for 2020, valuing vacuum residue as a waste product significantly reduces the LCOH; in this case by 38.2%. It remains important to identify sites where this occurs.

Case 4 – Alternative CO_2 T&S (France)

- In the future, other CO_2 storage sites become available that are closer to the point of production.
- In this case, shipping the low volume of CO_2 to the South of France is economically favourable over storage in the In Salah region. This again arises due to the economics of CO_2 shipping versus pipelines and may differ where H_2 production is part of a cluster.
- In this case, the LCOH is reduced by 6.5%, a marginal improvement.

Case 5 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs and the LCOH; by up to 28.4%.

Case 6 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 5 reveals a pathway to very low cost blue hydrogen from Algeria. The base case LCOH is reduced from €3.56/kgH_2 to €1.12/kgH_2; a 68.5% reduction.

Table 93: Summary of cases analysed for POX in Algeria in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Type	Baseline	Capex Reduction	Vacuum Residue as Waste Product	Alternative CO2 T&S (France)	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	Central Case	20% Learning Rate	Central Case	Central Case	Central Case	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Feedstock = Waste Product	Central Case	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Algeria (Pipe)	Algeria (Pipe)	Algeria (Pipe)	France (Ship)	Algeria (Pipe)	France (Ship)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

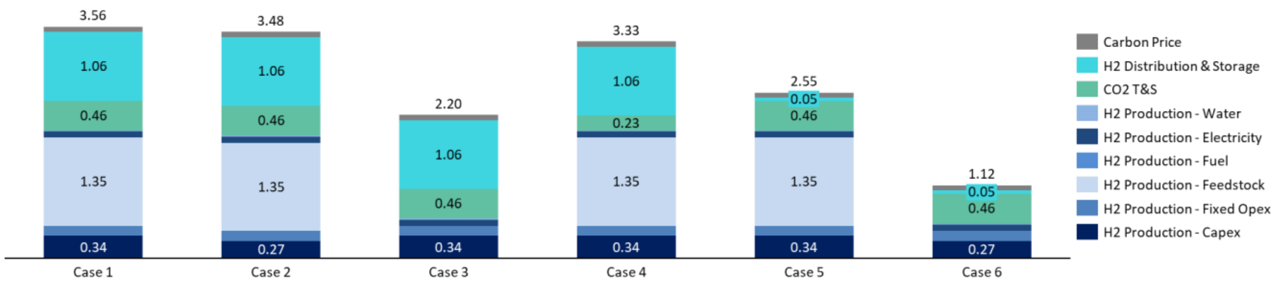

Figure 150: LCOH for POX (TRL 9) in Algeria in 2050 (€/kgH_2)

Libya SNR

Deployments in the 2020s

Two cases are explored for SNR in Libya from 2020. These are summarised in Table 94 with results displayed in Figure 151.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Alternative H_2 Distribution (North America Shipping)

- Case 2 proves that Libya could just as viably distribute hydrogen to North America as opposed to Western Europe. The distance increase of c. 4,900km only increases the LCOH by 4.3%.

Table 94: Summary of cases analysed for SNR in Libya in 2020

Sensitivity	Case 1	Case 2
Type	Baseline	Alternative H2 Distribution (Ship)
Capex & Fixed Opex	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Central Case
CO_2 Price	Central Case	Central Case
CO_2 T&S	Libya (Pipe)	Libya (Pipe)
H_2 Distribution	W. Europe (Ship)	N. America (Ship)

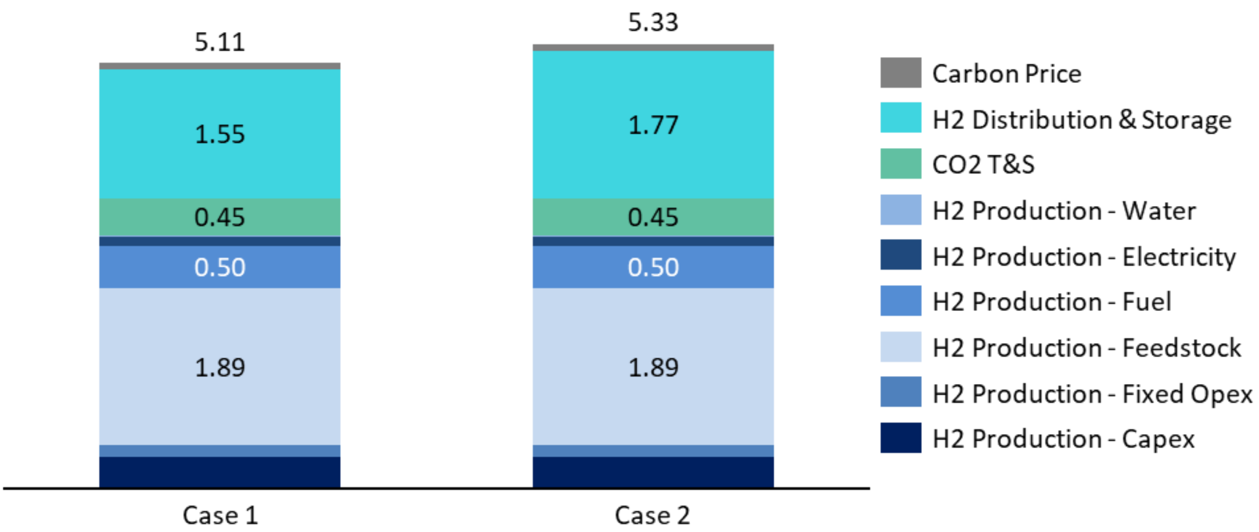

Figure 151: LCOH for SNR (TRL 9) in Libya in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 152. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the feedstock price, CO_2 T&S fee and H_2 distribution fee cost components does not significantly impact the LCOH due to the tighter band on the cost variation. In all cases, the variation of the cost component does not change the LCOH by more than +/- 4%.

Variation to the Capex, fixed Opex, electricity demand, water and carbon price has a cumulative impact of + / - 2.2% on the LCOH.

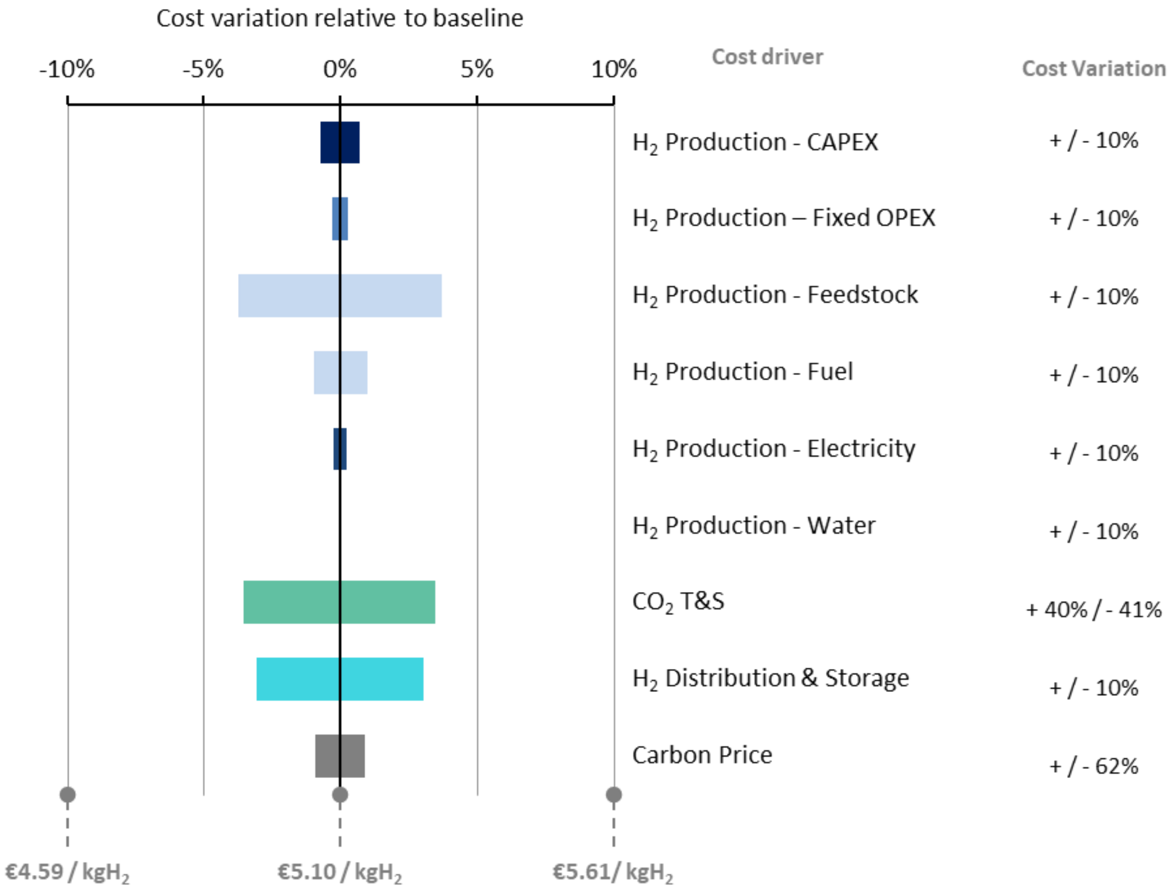

Figure 152: LCOH for SNR (TRL 9) in the Libya base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Four cases are explored for SNR in Libya from 2050. These are summarised in Table 95 with results displayed in Figure 153.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 1.4% reduction on the Base Case.

Case 3 – Local Hydrogen Demand

- As explored in Task 2 of this study, increased local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs and the LCOH; by up to 20.0%.

Case 4 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 and 3 reduces the base case LCOH from €5.06/kgH_2 to €3.98/kgH_2; a 21.3% reduction.

- Reductions in the LCOH for SNR are more challenging to achieve as naphtha feedstock is a refined oil product and therefore unlikely to be accessible as a waste feedstock.

Table 95: Summary of cases analysed for SNR in Libya in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4
Type	Baseline	Capex Reduction	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	5% Learning Rate	20% Learning Rate	5% Learning Rate	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Central Case
CO_2 Price	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Libya (Pipe)	Libya (Pipe)	Libya (Pipe)	Libya (Pipe)
H_2 Distribution	W. Europe (Ship)	W. Europe (Ship)	Local (Pipe)	Local (Pipe)

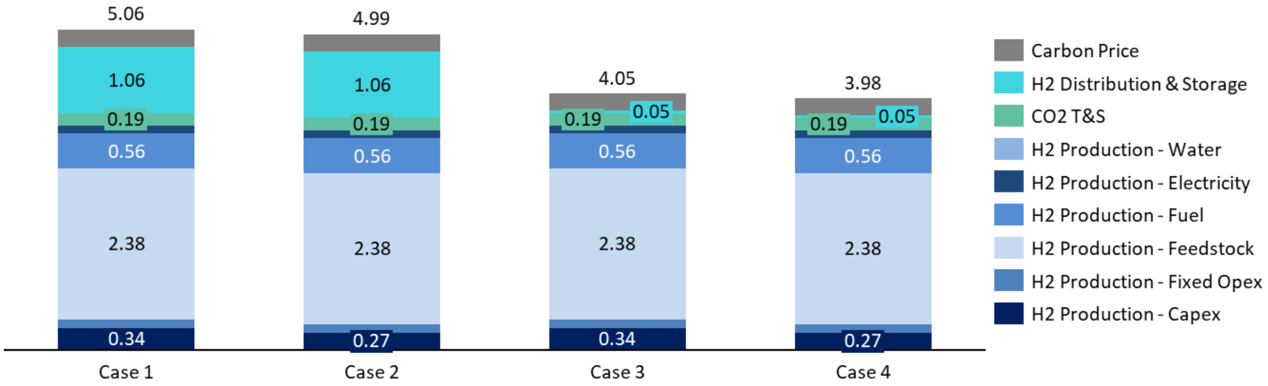

Figure 153: LCOH for SNR (TRL 9) in Libya in 2050 (€/kgH_2)

Brazil POX

Deployments in the 2020s

Four cases are explored for POX in Brazil from 2020. These are summarised in Table 96 with results displayed in Figure 154.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Valuing Vacuum Residue as a Waste Product

- Case 2 demonstrates the significant impact of the price of feedstock on the LCOH.
- By valuing the vacuum residue as a waste product instead of valuing it at the price of oil, the LCOH is reduced by 18.5%.
- It is therefore important to identify sites where the value of the feedstock tends to zero and removes / reduces the size of this cost component.

Case 3 – Alternative H_2 Distribution (W. Europe Shipping)

- Case 3 assumes that the hydrogen is distributed to Western Europe instead of North America by ship. This changes the LCOH by less than 0.5% since the route lengths are nearly identical.
- This suggests Brazil could support both markets where it can provide an attractive commercial offering.

Case 4 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 and Case 3 identifies a pathway to lower cost blue hydrogen from Brazil. The base case LCOH is reduced from €5.84/kgH_2 to €4.76/kgH_2; a 18.5% reduction.

Table 96: Summary of cases analysed for POX in Brazil in 2020

Sensitivity	Case 1	Case 2	Case 3	Case 4
Type	Baseline	Vacuum Residue as Waste Product	Alternative H2 Distribution (Shipping)	Lowest Cost Pathway
Capex & Fixed Opex	Central Case	Central Case	Central Case	Central Case
Feedstock, Fuel & Electricity	Central Case	Feedstock = Waste Product	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Brazil (Pipe)	Brazil (Pipe)	Brazil (Pipe)	Brazil (Pipe)
H_2 Distribution	N. America (Ship)	N. America (Ship)	W. Europe (Ship)	W. Europe (Ship)

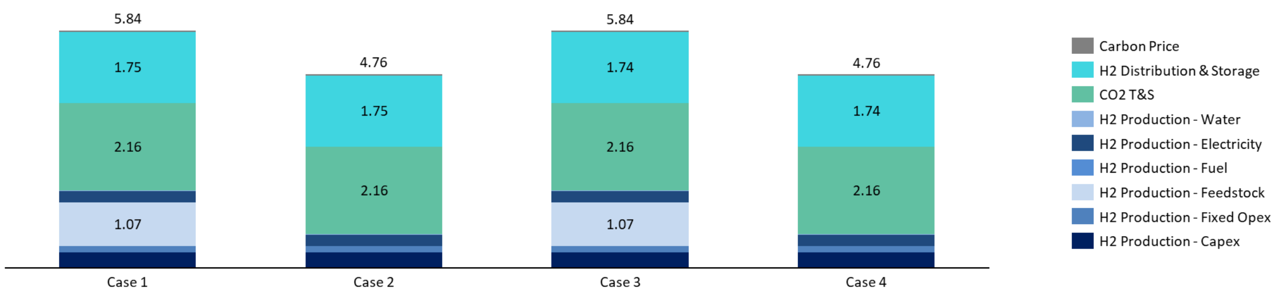

Figure 154: LCOH for POX (TRL 9) in Brazil in 2020 (€/kgH_2)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 155. As previously discussed, the feedstock price, CO_2 T&S fee and H_2 distribution fee are the most significant cost components. However, the variation of the feedstock price and H_2 distribution fee does not significantly impact the LCOH due to the tighter band on the cost variation. In both cases, the variation of the cost component does not change the LCOH by more than +/- 6%. The most significant variation comes from the CO_2 T&S fee due to the wide range. The CO_2 T&S fee is varied by + 39% / - 20% and this changes the LCOH by + 14.6% /- 7.6%. Variation to the Capex, fixed Opex, electricity demand and carbon price has a cumulative impact of + / - 1.7% on the LCOH.

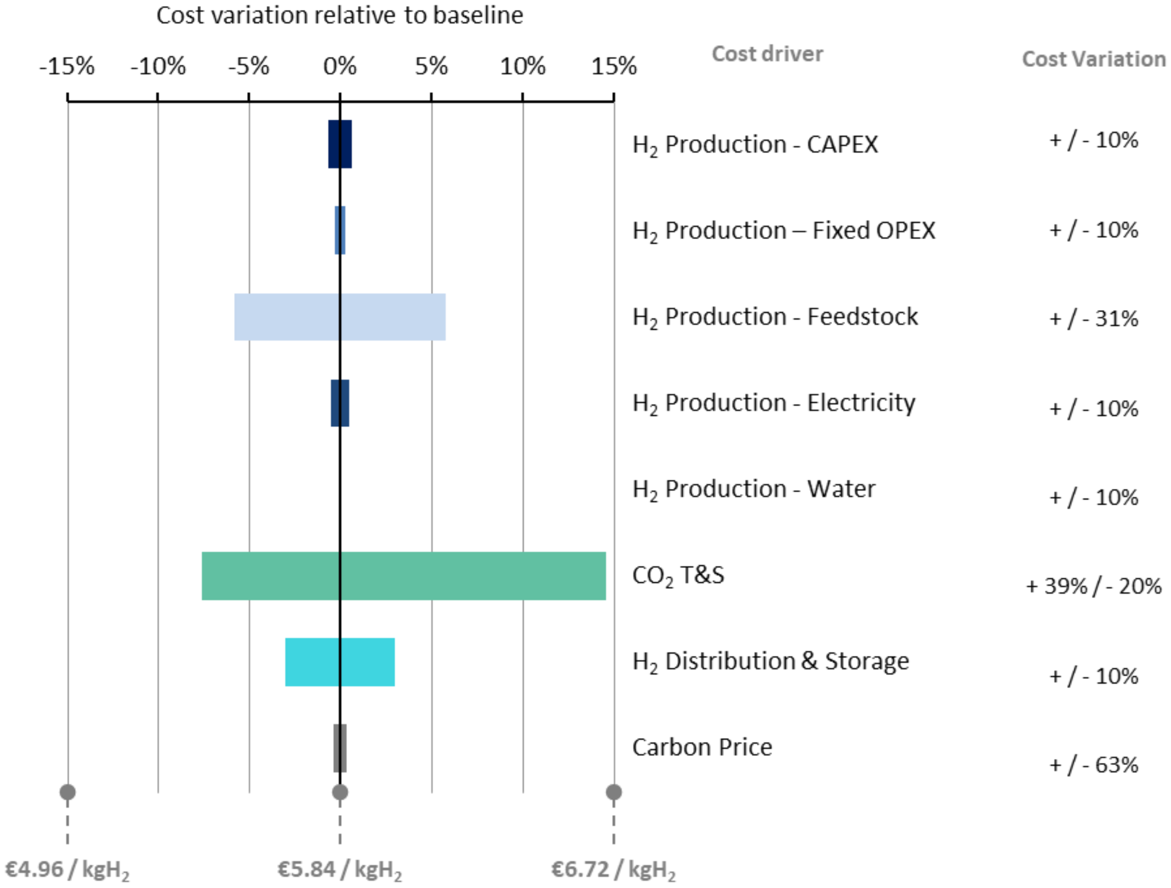

Figure 155: LCOH for POX (TRL 9) in the Brazil base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Five cases are explored for POX in Algeria in 2050. These are summarised in Table 97 with results displayed in Figure 156.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%. This has a marginal impact on the LCOH, with a 2.0% reduction on the Base Case.

Case 3 – Valuing Vacuum Residue as a Waste Product

- As for 2020, valuing vacuum residue as a waste product significantly reduces the LCOH; in this case by 33.4%. It remains important to identify sites where this occurs.

Case 4 – Local Hydrogen Demand

- As explored in Task 2 of this study, significant local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.

- This significantly reduces H_2 distribution costs and the LCOH; by up to 29.7%.

Case 5 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 4 reveals a pathway to very low cost blue hydrogen from Brazil. The base case LCOH is reduced from €4.07/kgH_2 to €1.43/kgH_2; a 64.9% reduction.

Table 97: Summary of cases analysed for POX in Brazil in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5
Type	Baseline	Capex Reduction	Vacuum Residue as Waste Product	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	Central Case	20% Learning Rate	Central Case	Central Case	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Feedstock = Waste Product	Central Case	Feedstock = Waste Product
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	Brazil (Pipe)	Brazil (Pipe)	Brazil (Pipe)	Brazil (Pipe)	Brazil (Pipe)
H_2 Distribution	N. America (Ship)	N. America (Ship)	N. America (Ship)	Local (Pipe)	Local (Pipe)

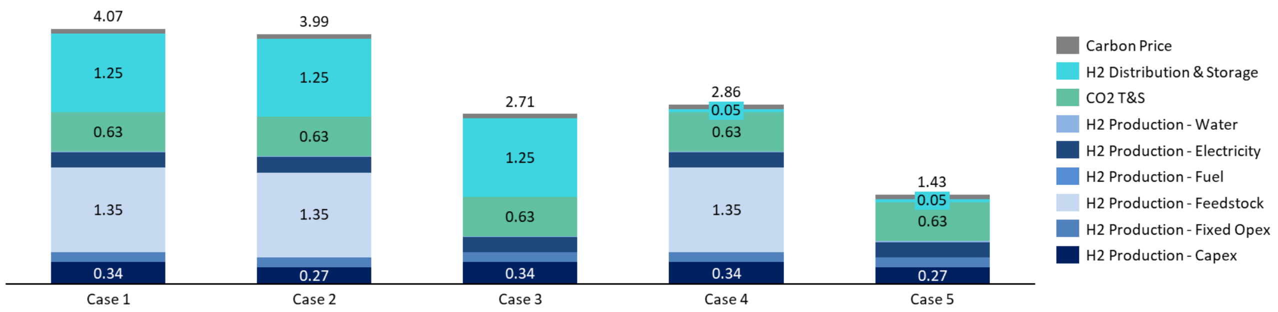

Figure 156: LCOH for POX (TRL 9) in Brazil in 2050 (€/kgH_2)

Venezuela HEE

Deployments in the 2020s

Seven cases are explored for HEE in Venezuela from 2020. These are summarised in Table 94 with results displayed in Figure 158.

Table 98: Summary of cases analysed for HEE in Venezuela in 2020

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Type	Baseline	Baseline & Grid Electricity	Low Cost Well Option	Oil from Well Priced as Zero	Oil from Well Priced as Zero & Grid Electricity	Alternative H2 Distribution (Pipeline)	Lowest Cost Pathway
Capex & Fixed Opex	New Well	New Well	Old Well	New Well	New Well	New Well	Old Well
Feedstock, Fuel & Electricity	Central Case & H2 Generator	Central Case & Grid Electricity	Central Case & H2 Generator	Feedstock Priced at Zero	Feedstock Priced at Zero & Grid Electricity	Central Case & H2 Generator	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	N. America (Ship)	N. America (Ship)	N. America (Ship)	N. America (Ship)	N. America (Ship)	W. Europe (Ship)	N. America (Ship)

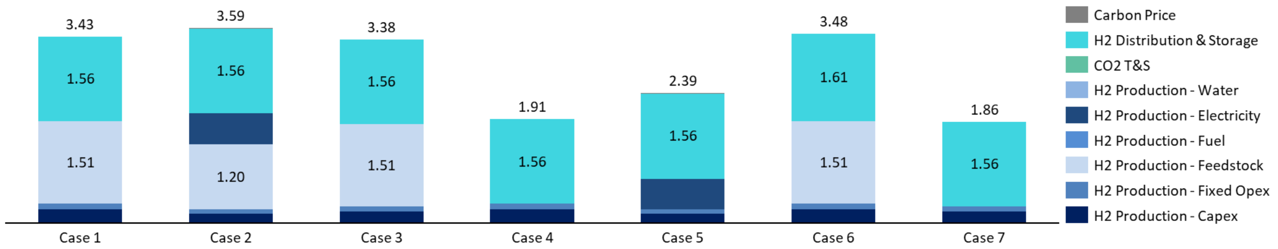

Figure 157: LCOH for HEE (TRL 4-6) in Venezuela in 2020 (€/kgH$_2$)

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.
- Process electricity demand is supplied by an on-site hydrogen generator.

Case 2 - Grid Electricity Supply

- Case 2 replaces the on-site hydrogen generator with electricity supplied from the grid.

Case 3 – Low Cost Well Option

- Where the technology operator can access existing infrastructure and pre-existing wells, it is possible to save upfront capital costs associated with well drilling based on Element Energy's bottom up cost analysis. Whilst the Capex is reduced by 14.4%, the overall LOCH is only reduced by 1.5%.

Case 4 – Oil from Well is Free

- In the base case, it is assumed that the technology operator has to account for the fact that oil is not sold to the market but instead converted to hydrogen.
- Where the value of this oil can be significantly depreciated or where the oil cannot be economically extracted, it can be valued as having zero cost.
- This significantly reduces the LCOH by 44.3%.

Case 5 – Oil from Well is Free & Grid Electricity

- Case 5 is the same as Case 4 with the on-site hydrogen generator replaced with electricity supplied from the grid.

Case 6 – Alternative H_2 Distribution (W. Europe Shipping)

- Case 6 proves that Venezuela could just as viably distribute hydrogen to Western Europe as opposed to North America. The distance increase of c. 3,750km only increases the LCOH by 1.5%.

Case 7 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 3 and 4 identifies a pathway to lower cost blue hydrogen from Venezuela. The base case LCOH is reduced from €3.43/kgH_2 to €1.86/kgH_2; a 45.8% reduction.

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 158. As previously discussed, the feedstock price and H_2 distribution fee are the most significant cost components. However, the variation of the H_2 distribution in our sensitivity analysis does not significantly impact the LCOH due to the tighter band on the cost variation. The most significant variation comes from the feedstock due to the wide range of oil prices. The price of the oil is varied by + / - 31% and this changes the LCOH by +/- 13.8%. Variation to the Capex, fixed Opex and hydrogen distribution and storage has a cumulative impact of + / - 5.6% on the LCOH.

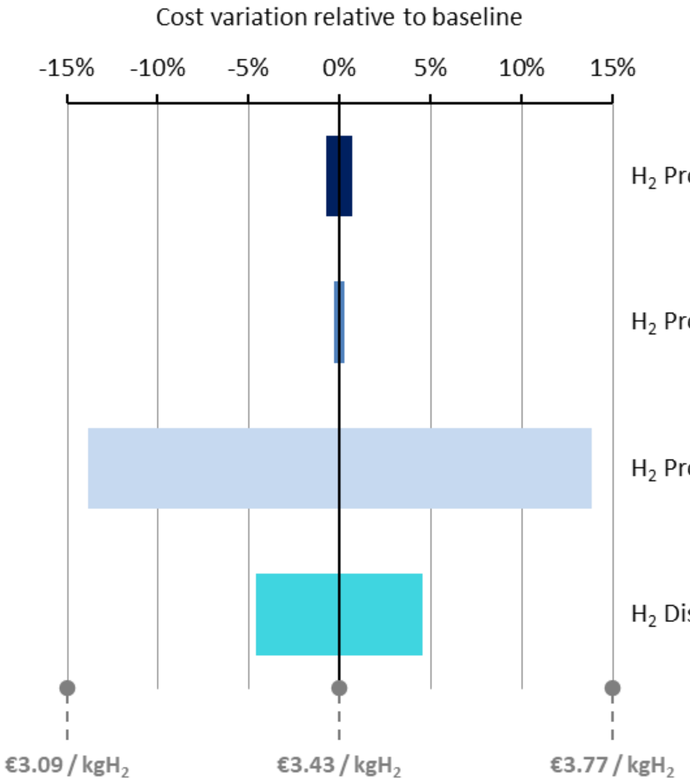

Figure 158: LCOH for HEE (TRL 4-6) in the Venezuela base case in 2020 (€/kgH_2)

Long-Term Technoeconomic Assessment (2050)

Six cases are explored for HEE in Venezuela from 2050. These are summarised in Table 99 with results displayed in Figure 159.

Overview & Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity and H_2 distribution.

Case 2 & 3 – Capex & Fixed Opex Reductions (15%) for New and Old Wells

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%.
- Since the Capex, in both cases, is comparatively small, the impact of further cost reductions is minimal. For the new well the LCOH reduction is 2.1% and for the old well the LCOH reduction is 3.3%.

Case 4 – Oil from Well is Free

- As for 2020, where the value of the oil is significantly depreciated or it cannot be extracted for commercial activities, there are significant cost reduction opportunities. In this case, the LCOH is reduced by 57.9%.

Case 5 – Local Hydrogen Demand

- As explored in Task 2 of this study, increased local demand for hydrogen is expected by 2050. It is therefore reasonable to expect that some of this hydrogen is used domestically.
- This significantly reduces H_2 distribution costs, reducing the LCOH by 30.9%. This significant cost reduction is indicative of the fact that near term markets for hydrogen remain a long way from Venezuela.

Case 6 – Lowest Cost Pathway

- Combining favourable sensitivities from Case 2 to 5 reveals a pathway to very low cost blue hydrogen from Venezuela. The base case LCOH is reduced from €3.3/kgH_2 to €0.26/kgH_2; a 92.1% reduction.

Table 99: Summary of cases analysed for HEE in Venezuela in 2050

Sensitivity	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Type	Baseline	Capex Reduction	Capex Reduction	Oil from Well Priced as Zero	Alternative H2 Distribution (Pipe)	Lowest Cost Pathway
Capex & Fixed Opex	New Well 5% Learning Rate	New Well 20% Learning Rate	Old Well 20% Learning Rate	New Well 5% Learning Rate	New Well 5% Learning Rate	Old Well 20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case	Central Case	Feedstock Priced at Zero	Central Case	Feedstock Priced at Zero
CO_2 Price	Central Case	Central Case	Central Case	Central Case	Central Case	Central Case
CO_2 T&S	N/A	N/A	N/A	N/A	N/A	N/A
H_2 Distribution	N. America (Ship)	N. America (Ship)	N. America (Ship)	N. America (Ship)	Local (Pipe)	Local (Pipe)

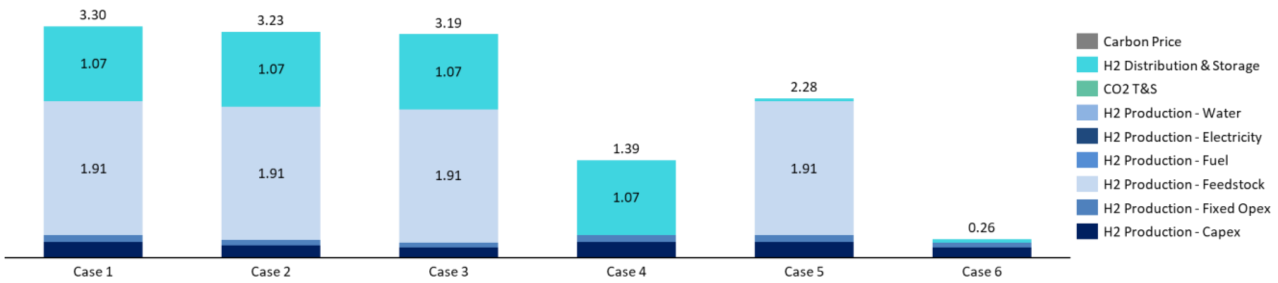

Figure 159: LCOH for HEE (TRL 4-6) in Venezuela in 2050 (€/kgH_2)

Netherlands SNR

Deployments in the 2020s

There is more certainty in the Netherlands hydrogen production pathway as the country already has a number of hydrogen and CCS projects in development. This is largely centred in the Port of Rotterdam as a large industrial cluster. Hydrogen distribution in this area is expected to meet the demand of local industry. Any H_2 production site will access the Porthos Project's CO_2 T&S infrastructure. A single base case is therefore analysed, as summarised in Table 100 with results displayed in Figure 160.

Table 100: SNR base case analysed in the Netherlands in 2020

Sensitivity	Case 1
Type	Base Case
Capex & Fixed Opex	Central Case
Feedstock, Fuel & Electricity	Central Case
CO_2 Price	Central Case
CO_2 T&S	Netherlands (Pipe)
H_2 Distribution	Local (Pipe)

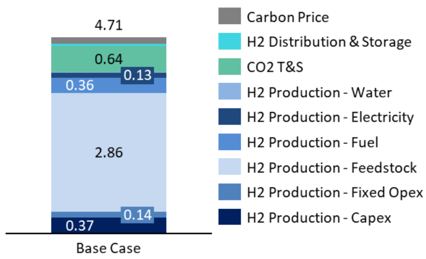

Figure 160: LCOH for SNR (TRL 9) in the Netherlands in 2020 (€/kgH₂)

The impact of varying each cost component by the specified sensitivity on the Base Case (Case 1) LCOH is displayed in Figure 161. As previously discussed, the feedstock price, plant Capex and CO_2 T&S fee are the most significant cost components. However, variation in the Capex makes a small difference to the LCOH. Variations in all cost components other than the cost of feedstock and CO_2 T&S fee do not change the LCOH by more than +/- 5%. The most significant variation comes from the cost of feedstock due to the wide range of naphtha prices. The naphtha cost is varied by + / - 35% and this changes the LCOH by + / - 21.2%. Variation to the Capex, fixed Opex, electricity demand and carbon price has a cumulative impact of + / - 3.6% on the LCOH.

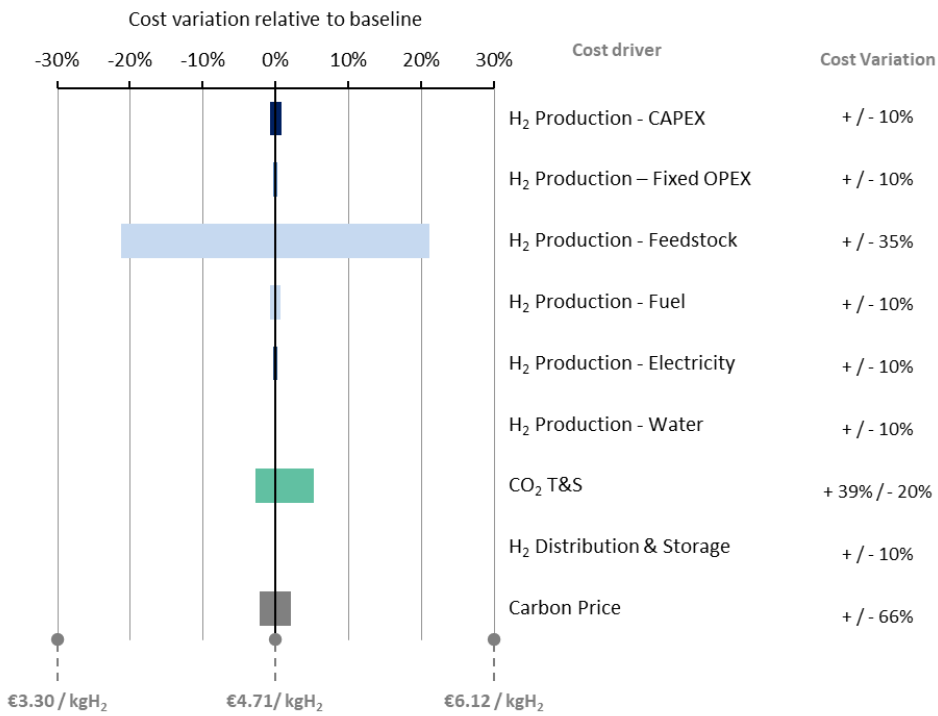

Figure 161: LCOH for SNR (TRL 9) in the Netherlands base case in 2020 (€/kgH₂)

Long-Term Technoeconomic Assessment (2050)

Only one variation from the base case has been analysed for the Netherlands in 2050. This is because many of the cost components have already been optimised:

- Hydrogen is distributed to local industry via pipeline
- CO_2 is transported to nearby storage via pipeline
- Rotterdam benefits from economies of scale generated from synergies in the industrial cluster

These are summarised in Table 101 with results displayed in Figure 162.

Base Case

- Case 1 is the Base Case, assuming central cost estimates for Capex, Opex, feedstock, electricity, CO_2 T&S and H_2 distribution.

Case 2 – Capex & Fixed Opex Reductions (15%)

- Increased levels of deployment will reduce the capital cost of installations. This is represented by a 20% learning rate resulting in a reduction in the Capex and fixed Opex of 15%.
- This has a marginal impact on the LCOH, with a 1.3% reduction on the Base Case.

Table 101: Summary of cases analysed for SNR in the Netherlands in 2050

Sensitivity	Case 1	Case 2
Type	Base Case	Capex Reduction
Capex & Fixed Opex	Central Case	20% Learning Rate
Feedstock, Fuel & Electricity	Central Case	Central Case
CO_2 Price	Central Case	Central Case
CO_2 T&S	Netherlands (Pipe)	Netherlands (Pipe)
H_2 Distribution	Local (Pipe)	Local (Pipe)

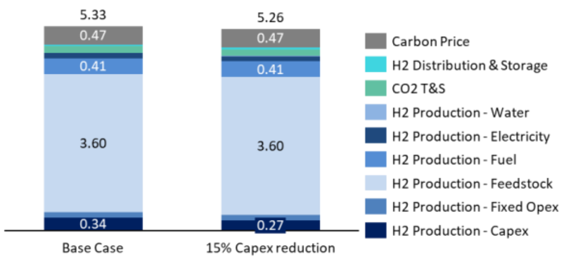

Figure 162: LCOH for SNR (TRL 9) in the Netherlands in 2050 (€/kgH_2)

9.6.2 TEA Tabulated Results

UAE SNR

Tabulated results for the stacked bar charts presented in the TEA analysis for SNR in the UAE in 2020 and 2050 are displayed in Table 102 and Table 103 respectively.

Table 102: SNR in the UAE in 2020

		Case 1	Case 2
Carbon Price	*€/kg*	0.12	0.12
H_2 Distribution & Storage	*€/kg*	1.80	1.81
CO_2 T&S	*€/kg*	0.50	0.50
H_2 Production - Water	*€/kg*	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.08	0.08
H_2 Production – Fuel	*€/kg*	0.05	0.05
H_2 Production – Feedstock	*€/kg*	0.99	0.99
H_2 Production – Fixed OPEX	*€/kg*	0.14	0.14
H_2 Production – CAPEX	*€/kg*	0.37	0.37
Power Export	*€/kg*	-	-
Total	***€/kg***	**4.06**	**4.08**

Table 103: SNR in the UAE in 2050

		Case 1	Case 2	Case 3	Case 4
Carbon Price	*€/kg*	0.35	0.35	0.35	0.35
H_2 Distribution & Storage	*€/kg*	1.31	1.31	0.05	0.05
CO_2 T&S	*€/kg*	0.17	0.17	0.17	0.17
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.08	0.08	0.08	0.08
H_2 Production – Fuel	*€/kg*	0.06	0.06	0.06	0.06
H_2 Production – Feedstock	*€/kg*	1.25	1.25	1.25	1.25
H_2 Production – Fixed OPEX	*€/kg*	0.14	0.14	0.14	0.14
H_2 Production – CAPEX	*€/kg*	0.34	0.27	0.34	0.27
Power Export	*€/kg*	-	-	-	-
Total	***€/kg***	**3.72**	**3.64**	**2.45**	**2.38**

Iran HEE

Tabulated results for the stacked bar charts presented in the TEA analysis for HEE in Iran in 2020 and 2050 are displayed in Table 104 and Table 105 respectively.

Table 104: HEE in Iran in 2020

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Carbon Price	€/kg	-	0.03	-	-	0.03	-	-
H_2 Distribution & Storage	€/kg	1.83	1.83	1.83	1.83	1.83	1.82	1.83
CO_2 T&S	€/kg	-	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	0.19	-	-	0.19	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.51	1.20	1.51	-	-	1.51	-
H_2 Production – Fixed OPEX	€/kg	0.10	0.07	0.09	0.10	0.07	0.10	0.09
H_2 Production – CAPEX	€/kg	0.25	0.17	0.21	0.25	0.17	0.25	0.21
Power Export	€/kg	-	-	-	-	-	-	-
Total	**€/kg**	**3.69**	**3.48**	**3.64**	**2.18**	**2.28**	**3.68**	**2.13**

Table 105: HEE in Iran in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Carbon Price	€/kg	-	-	-	-	-	-
H_2 Distribution & Storage	€/kg	1.34	1.34	1.34	1.34	0.05	0.05
CO_2 T&S	€/kg	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	-	-	-	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.91	1.91	1.91	-	1.91	-
H_2 Production – Fixed OPEX	€/kg	0.09	0.07	0.06	0.09	0.09	0.06
H_2 Production – CAPEX	€/kg	0.23	0.18	0.15	0.23	0.23	0.15
Power Export	€/kg	-	-	-	-	-	-
Total	**€/kg**	**3.57**	**3.50**	**3.46**	**1.66**	**2.28**	**0.26**

Iraq SNR

Tabulated results for the stacked bar charts presented in the TEA analysis for SNR in Iraq in 2020 and 2050 are displayed in Table 106 and Table 107 respectively.

Table 106: SNR in Iraq in 2020

		Case 1	Case 2
Carbon Price	€/kg	0.08	0.08
H_2 Distribution & Storage	€/kg	1.74	1.85
CO_2 T&S	€/kg	0.21	0.21
H_2 Production - Water	€/kg	0.01	0.01
H_2 Production - Electricity	€/kg	0.06	0.06
H_2 Production – Fuel	€/kg	0.21	0.21
H_2 Production – Feedstock	€/kg	1.89	1.89
H_2 Production – Fixed OPEX	€/kg	0.14	0.14
H_2 Production – CAPEX	€/kg	0.37	0.37
Power Export	€/kg	-	-
Total	**€/kg**	**4.71**	**4.82**

Table 107: SNR in Iraq in 2050

		Case 1	Case 2	Case 3	Case 4
Carbon Price	€/kg	0.26	0.26	0.26	0.26
H_2 Distribution & Storage	€/kg	1.25	1.25	0.05	0.05
CO_2 T&S	€/kg	0.09	0.09	0.09	0.09
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.05	0.05	0.05	0.05
H_2 Production – Fuel	€/kg	0.26	0.26	0.26	0.26
H_2 Production – Feedstock	€/kg	2.38	2.38	2.38	2.38
H_2 Production – Fixed OPEX	€/kg	0.14	0.14	0.14	0.14
H_2 Production – CAPEX	€/kg	0.34	0.27	0.34	0.27
Power Export	€/kg	-	-	-	-
Total	**€/kg**	**4.79**	**4.71**	**3.59**	**3.51**

Kuwait POX

Tabulated results for the stacked bar charts presented in the TEA analysis for POX in Kuwait in 2020 and 2050 are displayed in Table 108 and Table 109 respectively.

Table 108: POX in Kuwait in 2020

		Case 1	Case 2	Case 3	Case 4
Carbon Price	*€/kg*	0.13	0.13	0.14	0.13
H_2 Distribution & Storage	*€/kg*	1.74	1.74	1.74	1.73
CO_2 T&S	*€/kg*	0.13	0.13	1.16	0.13
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.02	0.02	0.02	0.02
H_2 Production – Fuel	*€/kg*	-	-	-	-
H_2 Production – Feedstock	*€/kg*	1.07	-	1.07	1.07
H_2 Production – Fixed OPEX	*€/kg*	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	*€/kg*	0.38	0.38	0.38	0.38
Power Export	*€/kg*	-	-	-	-
Total	***€/kg***	**3.63**	**2.56**	**4.68**	**3.62**

Table 109: POX in Kuwait in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Carbon Price	*€/kg*	0.21	0.21	0.21	0.23	0.21	0.21
H_2 Distribution & Storage	*€/kg*	1.25	1.25	1.25	1.25	0.05	0.05
CO_2 T&S	*€/kg*	0.05	0.05	0.05	0.33	0.05	0.05
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.02	0.02	0.02	0.02	0.02	0.02
H_2 Production – Fuel	*€/kg*	-	-	-	-	-	-
H_2 Production – Feedstock	*€/kg*	1.35	1.35	-	1.35	1.35	-
H_2 Production – Fixed OPEX	*€/kg*	0.16	0.16	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	*€/kg*	0.34	0.27	0.34	0.34	0.34	0.27
Power Export	*€/kg*	-	-	-	-	-	-
Total	***€/kg***	**3.41**	**3.33**	**2.05**	**3.71**	**2.21**	**0.78**

Saudi Arabia POX

Tabulated results for the stacked bar charts presented in the TEA analysis for POX in Saudi Arabia in 2020 and 2050 are displayed in Table 110 and Table 111 respectively.

Table 110: POX in Saudi Arabia in 2020

		Case 1	Case 2	Case 3
Carbon Price	€/kg	0.14	0.14	0.14
H_2 Distribution & Storage	€/kg	1.73	1.73	1.72
CO_2 T&S	€/kg	0.34	0.34	0.34
H_2 Production - Water	€/kg	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.15	0.15	0.15
H_2 Production – Fuel	€/kg	-	-	-
H_2 Production – Feedstock	€/kg	1.07	-	1.07
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.38	0.38	0.38
Power Export	€/kg	-	-	-
Total	**€/kg**	**3.98**	**2.90**	**3.96**

Table 111: POX in Saudi Arabia in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5
Carbon Price	€/kg	0.21	0.21	0.21	0.21	0.21
H_2 Distribution & Storage	€/kg	1.24	1.24	1.24	0.04	0.04
CO_2 T&S	€/kg	0.14	0.14	0.14	0.14	0.14
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.14	0.14	0.14	0.14	0.14
H_2 Production – Fuel	€/kg	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.35	1.35	-	1.35	-
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.34	0.27	0.34	0.34	0.27
Power Export	€/kg	-	-	-	-	-
Total	**€/kg**	**3.61**	**3.53**	**2.25**	**2.41**	**0.97**

Nigeria HEE

Tabulated results for the stacked bar charts presented in the TEA analysis for HEE in Nigeria in 2020 and 2050 are displayed in Table 112 and Table 113 respectively.

Table 112: HEE in Nigeria in 2020

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Carbon Price	€/kg	-	0.02	-	-	0.02	-	-	-
H_2 Distribution & Storage	€/kg	1.87	1.87	1.87	1.87	1.87	4.49	1.79	1.87
CO_2 T&S	€/kg	-	-	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	0.36	-	-	0.36	-	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.51	1.20	1.51	-	-	1.51	1.51	-
H_2 Production – Fixed OPEX	€/kg	0.10	0.07	0.09	0.10	0.07	0.10	0.10	0.09
H_2 Production – CAPEX	€/kg	0.25	0.17	0.21	0.25	0.17	0.25	0.25	0.21
Power Export	€/kg	-	-	-	-	-	-	-	-
Total	**€/kg**	**3.73**	**3.69**	**3.68**	**2.22**	**2.49**	**6.36**	**3.65**	**2.17**

Table 113: HEE in Nigeria in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Carbon Price	€/kg	-	-	-	-	-	-
H_2 Distribution & Storage	€/kg	1.38	1.38	1.38	1.38	0.05	0.05
CO_2 T&S	€/kg	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	-	-	-	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.91	1.91	1.91	-	1.91	-
H_2 Production – Fixed OPEX	€/kg	0.09	0.07	0.06	0.09	0.09	0.06
H_2 Production – CAPEX	€/kg	0.23	0.18	0.15	0.23	0.23	0.15
Power Export	€/kg	-	-	-	-	-	-
Total	**€/kg**	**3.61**	**3.54**	**3.50**	**1.70**	**2.28**	**0.26**

Republic of Congo POX

Tabulated results for the stacked bar charts presented in the TEA analysis for POX in the Republic of Congo in 2020 and 2050 are displayed in Table 114 and Table 115 respectively.

Table 114: POX in the Republic of Congo in 2020

		Case 1	Case 2	Case 3
Carbon Price	€/kg	0.06	0.06	0.06
H_2 Distribution & Storage	€/kg	1.66	1.66	1.78
CO_2 T&S	€/kg	0.59	0.59	0.59
H_2 Production - Water	€/kg	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.30	0.30	0.30
H_2 Production – Fuel	€/kg	-	-	-
H_2 Production – Feedstock	€/kg	1.07	-	1.07
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.38	0.38	0.38
Power Export	€/kg	-	-	-
Total	**€/kg**	**4.22**	**3.14**	**4.34**

Table 115: POX in the Republic of Congo in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5
Carbon Price	€/kg	0.09	0.09	0.09	0.09	0.09
H_2 Distribution & Storage	€/kg	1.17	1.17	1.17	0.05	0.05
CO_2 T&S	€/kg	0.17	0.17	0.17	0.17	0.17
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.29	0.29	0.29	0.29	0.29
H_2 Production – Fuel	€/kg	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.35	1.35	-	1.35	-
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.34	0.27	0.34	0.34	0.27
Power Export	€/kg	-	-	-	-	-
Total	**€/kg**	**3.58**	**3.50**	**2.22**	**2.46**	**1.03**

Equatorial Guinea HEE

Tabulated results for the stacked bar charts presented in the TEA analysis for HEE in Equatorial Guinea in 2020 and 2050 are displayed in Table 116 and Table 117 respectively.

Table 116: HEE in Equatorial Guinea in 2020

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Carbon Price	€/kg	-	0.02	-	-	0.02	-	-
H_2 Distribution & Storage	€/kg	1.67	1.67	1.67	1.67	1.67	1.78	1.67
CO_2 T&S	€/kg	-	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	0.62	-	-	0.62	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.51	1.20	1.51	-	-	1.51	-
H_2 Production – Fixed OPEX	€/kg	0.10	0.07	0.09	0.10	0.07	0.10	0.09
H_2 Production – CAPEX	€/kg	0.25	0.17	0.21	0.25	0.17	0.25	0.21
Power Export	€/kg	-	-	-	-	-	-	-
Total	**€/kg**	**3.53**	**3.76**	**3.48**	**2.02**	**2.56**	**3.64**	**1.97**

Table 117: HEE in Equatorial Guinea in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Carbon Price	€/kg	-	-	-	-	-	-
H_2 Distribution & Storage	€/kg	1.18	1.18	1.18	1.18	0.04	0.04
CO_2 T&S	€/kg	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	-	-	-	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.91	1.91	1.91	-	1.91	-
H_2 Production – Fixed OPEX	€/kg	0.09	0.07	0.06	0.09	0.09	0.06
H_2 Production – CAPEX	€/kg	0.23	0.18	0.15	0.23	0.23	0.15
Power Export	€/kg	-	-	-	-	-	-
Total	**€/kg**	**3.41**	**3.34**	**3.30**	**1.50**	**2.27**	**0.25**

Gabon POX

Tabulated results for the stacked bar charts presented in the TEA analysis for HEE in Equatorial Guinea in 2020 and 2050 are displayed in Table 118 and Table 119 respectively.

Table 118: POX in Gabon in 2020

		Case 1	Case 2	Case 3
Carbon Price	€/kg	0.04	0.04	0.04
H_2 Distribution & Storage	€/kg	1.63	1.63	1.77
CO_2 T&S	€/kg	0.59	0.59	0.59
H_2 Production - Water	€/kg	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.61	0.61	0.61
H_2 Production – Fuel	€/kg	-	-	-
H_2 Production – Feedstock	€/kg	1.07	-	1.07
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.38	0.38	0.38
Power Export	€/kg	-	-	-
Total	**€/kg**	**4.49**	**3.41**	**4.62**

Table 119: POX in Gabon in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5
Carbon Price	€/kg	0.09	0.09	0.09	0.09	0.09
H_2 Distribution & Storage	€/kg	1.14	1.14	1.14	0.05	0.05
CO_2 T&S	€/kg	0.17	0.17	0.17	0.17	0.17
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.59	0.59	0.59	0.59	0.59
H_2 Production – Fuel	€/kg	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.35	1.35	-	1.35	-
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.34	0.27	0.34	0.34	0.27
Power Export	€/kg	-	-	-	-	-
Total	**€/kg**	**3.85**	**3.78**	**2.50**	**2.76**	**1.33**

Angola SNR

Tabulated results for the stacked bar charts presented in the TEA analysis for HEE in Equatorial Guinea in 2020 and 2050 are displayed in Table 120 and Table 121 respectively.

Table 120: SNR in Angola in 2020

		Case 1	Case 2	Case 3
Carbon Price	*€/kg*	0.07	0.08	0.07
H_2 Distribution & Storage	*€/kg*	1.65	1.65	1.79
CO_2 T&S	*€/kg*	1.54	2.40	1.54
H_2 Production - Water	*€/kg*	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.04	0.04	0.04
H_2 Production – Fuel	*€/kg*	0.36	0.36	0.36
H_2 Production – Feedstock	*€/kg*	1.89	1.89	1.89
H_2 Production – Fixed OPEX	*€/kg*	0.14	0.14	0.14
H_2 Production – CAPEX	*€/kg*	0.37	0.37	0.37
Power Export	*€/kg*	-	-	-
Total	***€/kg***	**6.06**	**6.94**	**6.20**

Table 121: SNR in Angola in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5
Carbon Price	*€/kg*	0.17	0.17	0.20	0.17	0.17
H_2 Distribution & Storage	*€/kg*	1.16	1.16	1.16	0.05	0.05
CO_2 T&S	*€/kg*	0.40	0.40	0.63	0.40	0.40
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.04	0.04	0.04	0.04	0.04
H_2 Production – Fuel	*€/kg*	0.40	0.40	0.40	0.40	0.40
H_2 Production – Feedstock	*€/kg*	2.38	2.38	2.38	2.38	2.38
H_2 Production – Fixed OPEX	*€/kg*	0.14	0.14	0.14	0.14	0.14
H_2 Production – CAPEX	*€/kg*	0.34	0.27	0.34	0.34	0.27
Power Export	*€/kg*	-	-	-	-	-
Total	***€/kg***	**5.05**	**4.97**	**5.31**	**3.94**	**3.86**

Algeria POX

Tabulated results for the stacked bar charts presented in the TEA analysis for POX in Algeria in 2020 and 2050 are displayed in Table 122 and Table 123 respectively.

Table 122: POX in Algeria 2020

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Carbon Price	€/kg	0.05	0.05	0.06	0.05	0.05	0.06
H_2 Distribution & Storage	€/kg	1.55	1.55	1.55	3.03	1.65	1.55
CO_2 T&S	€/kg	1.37	1.37	1.09	1.37	1.37	1.09
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.11	0.11	0.11	0.11	0.11	0.11
H_2 Production – Fuel	€/kg	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.07	-	1.07	1.07	1.07	-
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.38	0.38	0.38	0.38	0.38	0.38
Power Export	€/kg	-	-	-	-	-	-
Total	**€/kg**	**4.70**	**3.62**	**4.42**	**6.18**	**4.80**	**3.35**

Table 123: POX in Algeria 2050

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Carbon Price	€/kg	0.08	0.08	0.08	0.08	0.08	0.08
H_2 Distribution & Storage	€/kg	1.06	1.06	1.06	1.06	0.05	0.05
CO_2 T&S	€/kg	0.46	0.46	0.46	0.23	0.46	0.46
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.09	0.09	0.09	0.09	0.09	0.09
H_2 Production – Fuel	€/kg	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.35	1.35	-	1.35	1.35	-
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.34	0.27	0.34	0.34	0.34	0.27
Power Export	€/kg	-	-	-	-	-	-
Total	**€/kg**	**3.56**	**3.48**	**2.20**	**3.33**	**2.55**	**1.12**

Libya SNR

Tabulated results for the stacked bar charts presented in the TEA analysis for POX in Algeria in 2020 and 2050 are displayed in Table 124 and Table 125 respectively.

Table 124: SNR in Libya in 2020

		Case 1	Case 2
Carbon Price	€/kg	0.07	0.07
H_2 Distribution & Storage	€/kg	1.55	1.77
CO_2 T&S	€/kg	0.45	0.45
H_2 Production - Water	€/kg	0.01	0.01
H_2 Production - Electricity	€/kg	0.12	0.12
H_2 Production – Fuel	€/kg	0.50	0.50
H_2 Production – Feedstock	€/kg	1.89	1.89
H_2 Production – Fixed OPEX	€/kg	0.14	0.14
H_2 Production – CAPEX	€/kg	0.37	0.37
Power Export	€/kg	-	-
Total	**€/kg**	**5.11**	**5.33**

Table 125: SNR in Libya in 2050

		Case 1	Case 2	Case 3	Case 4
Carbon Price	€/kg	0.26	0.26	0.26	0.26
H_2 Distribution & Storage	€/kg	1.06	1.06	0.05	0.05
CO_2 T&S	€/kg	0.19	0.19	0.19	0.19
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.12	0.12	0.12	0.12
H_2 Production – Fuel	€/kg	0.56	0.56	0.56	0.56
H_2 Production – Feedstock	€/kg	2.38	2.38	2.38	2.38
H_2 Production – Fixed OPEX	€/kg	0.14	0.14	0.14	0.14
H_2 Production – CAPEX	€/kg	0.34	0.27	0.34	0.27
Power Export	€/kg	-	-	-	-
Total	**€/kg**	**5.06**	**4.99**	**4.05**	**3.98**

Brazil POX

Tabulated results for the stacked bar charts presented in the TEA analysis for POX in Brazil in 2020 and 2050 are displayed in Table 126 and Table 127 respectively.

Table 126: POX in Brazil 2020

		Case 1	Case 2	Case 3	Case 4
Carbon Price	€/kg	0.03	0.03	0.03	0.03
H_2 Distribution & Storage	€/kg	1.75	1.75	1.74	1.74
CO_2 T&S	€/kg	2.16	2.16	2.16	2.16
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.28	0.28	0.28	0.28
H_2 Production – Fuel	€/kg	-	-	-	-
H_2 Production – Feedstock	€/kg	1.07	-	1.07	-
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.38	0.38	0.38	0.38
Power Export	€/kg	-	-	-	-
Total	**€/kg**	**5.84**	**4.76**	**5.84**	**4.76**

Table 127: POX in Brazil 2050

		Case 1	Case 2	Case 3	Case 4	Case 5
Carbon Price	€/kg	0.07	0.07	0.07	0.07	0.07
H_2 Distribution & Storage	€/kg	1.25	1.25	1.25	0.05	0.05
CO_2 T&S	€/kg	0.63	0.63	0.63	0.63	0.63
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.24	0.24	0.24	0.24	0.24
H_2 Production – Fuel	€/kg	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.35	1.35	-	1.35	-
H_2 Production – Fixed OPEX	€/kg	0.16	0.16	0.16	0.16	0.16
H_2 Production – CAPEX	€/kg	0.34	0.27	0.34	0.34	0.27
Power Export	€/kg	-	-	-	-	-
Total	**€/kg**	**4.07**	**3.99**	**2.71**	**2.86**	**1.43**

Venezuela HEE

Tabulated results for the stacked bar charts presented in the TEA analysis for POX in Brazil in 2020 and 2050 are displayed in Table 128 and Table 129 respectively.

Table 128: HEE in Venezuela in 2020

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Carbon Price	€/kg	-	0.01	-	-	0.01	-	-
H_2 Distribution & Storage	€/kg	1.56	1.56	1.56	1.56	1.56	1.61	1.56
CO_2 T&S	€/kg	-	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	0.57	-	-	0.57	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.51	1.20	1.51	-	-	1.51	-
H_2 Production – Fixed OPEX	€/kg	0.10	0.07	0.09	0.10	0.07	0.10	0.09
H_2 Production – CAPEX	€/kg	0.25	0.17	0.21	0.25	0.17	0.25	0.21
Power Export	€/kg	-	-	-	-	-	-	-
Total	**€/kg**	**3.43**	**3.59**	**3.38**	**1.91**	**2.39**	**3.48**	**1.86**

Table 129: HEE in Venezuela in 2050

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Carbon Price	€/kg	-	-	-	-	-	-
H_2 Distribution & Storage	€/kg	1.07	1.07	1.07	1.07	0.05	0.05
CO_2 T&S	€/kg	-	-	-	-	-	-
H_2 Production - Water	€/kg	-	-	-	-	-	-
H_2 Production - Electricity	€/kg	-	-	-	-	-	-
H_2 Production – Fuel	€/kg	-	-	-	-	-	-
H_2 Production – Feedstock	€/kg	1.91	1.91	1.91	-	1.91	-
H_2 Production – Fixed OPEX	€/kg	0.09	0.07	0.06	0.09	0.09	0.06
H_2 Production – CAPEX	€/kg	0.23	0.18	0.15	0.23	0.23	0.15
Power Export	€/kg	-	-	-	-	-	-
Total	**€/kg**	**3.30**	**3.23**	**3.19**	**1.39**	**2.28**	**0.26**

SNR Netherlands

Tabulated results for the stacked bar charts presented in the TEA analysis for SNR in the Netherlands in 2020 and 2050 are displayed in Table 130.

Table 130: SNR in the Netherlands in 2020 and 2050

		2020 Case 1	2050 Case 1	2050 Case 2
Carbon Price	€/kg	0.16	0.47	0.47
H_2 Distribution & Storage	€/kg	0.05	0.05	0.05
CO_2 T&S	€/kg	0.64	0.17	0.17
H_2 Production - Water	€/kg	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.13	0.14	0.14
H_2 Production – Fuel	€/kg	0.36	0.41	0.41
H_2 Production – Feedstock	€/kg	2.86	3.60	3.60
H_2 Production – Fixed OPEX	€/kg	0.14	0.14	0.14
H_2 Production – CAPEX	€/kg	0.37	0.34	0.27
Power Export	€/kg	-	-	-
Total	**€/kg**	**4.71**	**5.33**	**5.26**

9.6.3 LCA Tabulated Results

In this appendix, all LCA results given in Section 6.3.2, are provided in tables.

Table 131 – Base analysis (Section 6.3.2). Carbon footprint (kg CO_2 eq./kg H_2) of each SNR hydrogen production scenario.

	Benchmark (SMR, no CCS, NL) TRL 9	SNR + CCS (TRL 9)				
	NL	Angola	Iraq	Libya	NL	UAE
Naphtha / vacuum residue / crude oil	-	1.17	1.17	1.17	1.13	1.17
Natural gas	1.12	0.32	0.32	0.32	0.34	0.32
Electricity from grid	-	0.49	1.35	0.96	0.62	0.68
Transport & Storage CO_2	-	0.12	0.14	0.28	0.06	0.16
Direct CO_2 emissions	9.00	1.29	1.29	1.29	1.29	1.29
of which: Generate CO_2	9.00	12.93	12.93	12.93	12.93	12.93
of which: Stored CO_2	-	11.64	11.64	11.64	11.64	11.64
Other	0.00	0.01	0.01	0.01	0.00	0.01
Total	10.13	3.39	4.28	4.02	3.44	3.62

Table 132 - Base analysis (Section 6.3.2). Carbon footprint (kg CO_2 eq./kg H_2) of each POX hydrogen production scenario.

	Benchmark (SMR, no CCS, NL) TRL 9	POX + CCS (TRL 9)					
	NL	Algeria	Brazil	Gabon	Kuwait	R. Congo	Saudi Arabia
Naphtha / vacuum residue / crude oil	-	1.18	1.10	1.18	1.18	1.18	1.18
Natural gas	1.12	-	-	-	-	-	-
Electricity from grid	-	2.24	0.72	1.19	3.00	2.58	3.68
Transport & Storage CO_2	-	0.83	0.20	0.04	0.08	0.07	0.20
Direct CO_2 emissions	9.00	0.32	0.32	0.32	0.32	0.32	0.32
of which: Generated CO2	9.00	9.12	9.12	9.12	9.12	9.12	9.12
of which: Stored CO2	-	8.80	8.80	8.80	8.80	8.80	8.80
Other	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Total	10.13	4.57	2.35	2.74	4.59	4.16	5.39

Table 133 - Base analysis (Section 6.3.2). Carbon footprint (kg CO_2 eq./kg H_2) of each HEE hydrogen production scenario.

	Benchmark (SMR, no CCS, NL) TRL 9	HEE + CCS (TRL 4-6)			
	NL	E. Guinea	Iran	Nigeria	Venezuela
Naphtha / vacuum residue / crude oil	-	-	-	-	-
Natural gas	1.12	-	-	-	-
Electricity from grid	-	2.91	2.66	2.00	1.36
Transport & Storage CO_2	-	-	-	-	-
Direct CO_2 emissions	9.00	-	-	-	-
of which: Generated CO_2	9.00	11.00	11.00	11.00	11.00
of which: Stored CO_2	-	11.00	11.00	11.00	11.00
Other	0.00	-	-	-	-
Total	10.13	2.91	2.66	2.00	1.36

Table 134 – Sensitivity analysis 1 (Section 6.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of each SNR hydrogen production scenario – electricity 2030

	Benchmark (SMR, no CCS, NL) TRL 9 – electricity 2030	SNR + CCS (TRL 9) – electricity 2030				
	NL	Angola	Iraq	Libya	NL	UAE
Naphtha / vacuum residue / crude oil	-	1.17	1.17	1.17	1.13	1.17
Natural gas	1.12	0.32	0.32	0.32	0.34	0.32
Electricity from grid	-	0.37	1.19	0.72	0.21	0.60
Transport & Storage CO_2	-	0.12	0.14	0.28	0.06	0.16
Direct CO_2 emissions	9.00	1.29	1.29	1.29	1.29	1.29
of which: Generated CO_2	9.00	12.93	12.93	12.93	12.93	12.93
of which: Stored CO_2	-	11.64	11.64	11.64	11.64	11.64
Other	0.00	0.01	0.01	0.01	0.00	0.01
Total	10.13	3.39	4.28	4.02	3.44	3.62

Table 135 – Sensitivity analysis 1 (Section 6.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of each POX hydrogen production scenario – electricity 2030

	Benchmark (SMR, no CCS, NL) TRL 9 – electricity 2030	POX + CCS (TRL 9) – electricity 2030					
	NL	Algeria	Brazil	Gabon	Kuwait	R. Congo	Saudi Arabia
Naphtha / vacuum residue / crude oil	-	1.18	1.10	1.18	1.18	1.18	1.18
Natural gas	1.12	-	-	-	-	-	-
Electricity from grid	-	1.69	0.52	0.89	2.65	1.95	3.26
Transport & Storage CO_2	-	0.83	0.20	0.04	0.08	0.07	0.20
Direct CO_2 emissions	9.00	0.32	0.32	0.32	0.32	0.32	0.32
of which: Generated CO_2	9.00	9.12	9.12	9.12	9.12	9.12	9.12
of which: Stored CO_2	-	8.80	8.80	8.80	8.80	8.80	8.80
Other	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Total	10.13	4.57	2.35	2.74	4.59	4.16	5.39

Table 136 - **Sensitivity analysis 1 (Section 6.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of each HEE hydrogen production scenario – electricity 2030**

	Benchmark (SMR, no CCS, NL) TRL 9 – electricity 2030	HEE + CCS (TRL 4-6) – electricity 2030			
	NL	E. Guinea	Iran	Nigeria	Venezuela
Naphtha / vacuum residue / crude oil	-	-	-	-	-
Natural gas	1.12	-	-	-	-
Electricity from grid	-	2.20	2.35	1.51	1.00
Transport & Storage CO_2	-	-	-	-	-
Direct CO_2 emissions	9.00	-	-	-	-
of which: Generate CO_2	9.00	11.00	11.00	11.00	11.00
of which: Stored CO_2	-	11.00	11.00	11.00	11.00
Other	0.00	-	-	-	-
Total	10.13	2.91	2.66	2.00	1.36

Table 137 - Sensitivity analysis 2 (Section 6.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of SNR in NL with a carbon capture rate of 99%

	SNR – NL TRL 9 – carbon capture rate 99%
Naphtha / vacuum residue / crude oil	1.13
Natural gas	0.34
Electricity from grid	0.62
Transport & Storage CO_2	0.06
Direct CO_2 emissions	0.13
of which: Generated CO_2	12.93
of which: Stored CO_2	12.80
Other	0.00
Total	3.44

Table 138 – Sensitivity analysis 3 (Section 6.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of selected hydrogen production scenarios with other CO_2 transport and storage scenarios

	SNR - Angola TRL 9 – T&S CO_2 Shipping	POX - Algeria TRL 9 – T&S CO_2 Shipping scenario 1	POX - Algeria TRL 9 – T&S CO_2 Shipping scenario 2	POX - Kuwait TRL 9 – T&S CO_2 Shipping
Naphtha / vacuum residue / crude oil	1.17	1.18	1.18	1.18
Natural gas	0.32	-	-	-
Electricity from grid	0.49	2.24	2.24	3.00
Transport & Storage CO_2	0.82	0.41	0.31	0.50
Direct CO_2 emissions	1.29	0.32	0.32	0.32
of which: Generated CO_2	12.93	9.12	9.12	9.12
of which: Stored CO_2	11.64	8.80	8.80	8.80
Other	0.01	0.01	0.01	0.01
Total	4.09	4.15	4.06	5.01

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