Fuel production cost estimates and assumptions.

This is part of Zero-Emission Vessels: Transition Pathways.

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Contents

Zero-carbon fuel production summary.

Decarbonising shipping is strongly linked to the evolution of zero-carbon fuel production and supply. So, in order to understand the conditions necessary for shipping's transition to zero-carbon, we need to consider how production and transportation. We have considered a range of possible pathways as presented in Figure 1, which are composed of fuel production, transportation, bunkering and vessel storage.

These potential pathways consider hydrogen, ammonia, methanol, gas oil and electricity as the final energy carriers on board ships. The primary energy sources considered to produce these include: natural gas with capture and storage (CCS) for hydrogen and ammonia, biomass for methanol and gas oil and renewable electricity for hydrogen, ammonia, e-methanol, e-gasoil, electricity with batteries.

This report provides supporting data and details assumptions in relation to the fuels used in the Zero-Emission Vessels: Transition Pathways report. In particular, we analysed potential costs and emissions associated with the fuels considered in this study. They are assumed to be the potential future marine fuels in a decarbonised system.

Cost estimates are considered in relation to these production processes and composed of primary energy sources, production plant type, emissions abatement, technology discounting and transportation. These are shown in Figure 2 as a comparison to reference cases of fossil-based fuels which are used today. A breakdown of these cost estimates for the renewable electricity-derived (electro-fuel) options are also included in Figures 3 – 9, in which an itemisation of the production cost has been undertaken in accordance with the specific process requirements.

We used these cost estimates as a proxy for future fuel prices in our reference scenario. However, in the sensitivity scenarios, we considered a wider range (upper and lower bound) from the estimated value in order to Identify the milestones (break-even point (BEP)) in the transition pathways report.

We do not want to address shipping's decarbonisation by shifting the problem upstream, so emissions from production and distribution need to be considered. The emissions attributable to the production and transportation where necessary are also provided below in Figures 9 – 14 for Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O), Oxides of Nitrogen (NOx), Oxides of Sulphur (SOx) and particulate matter (PM).

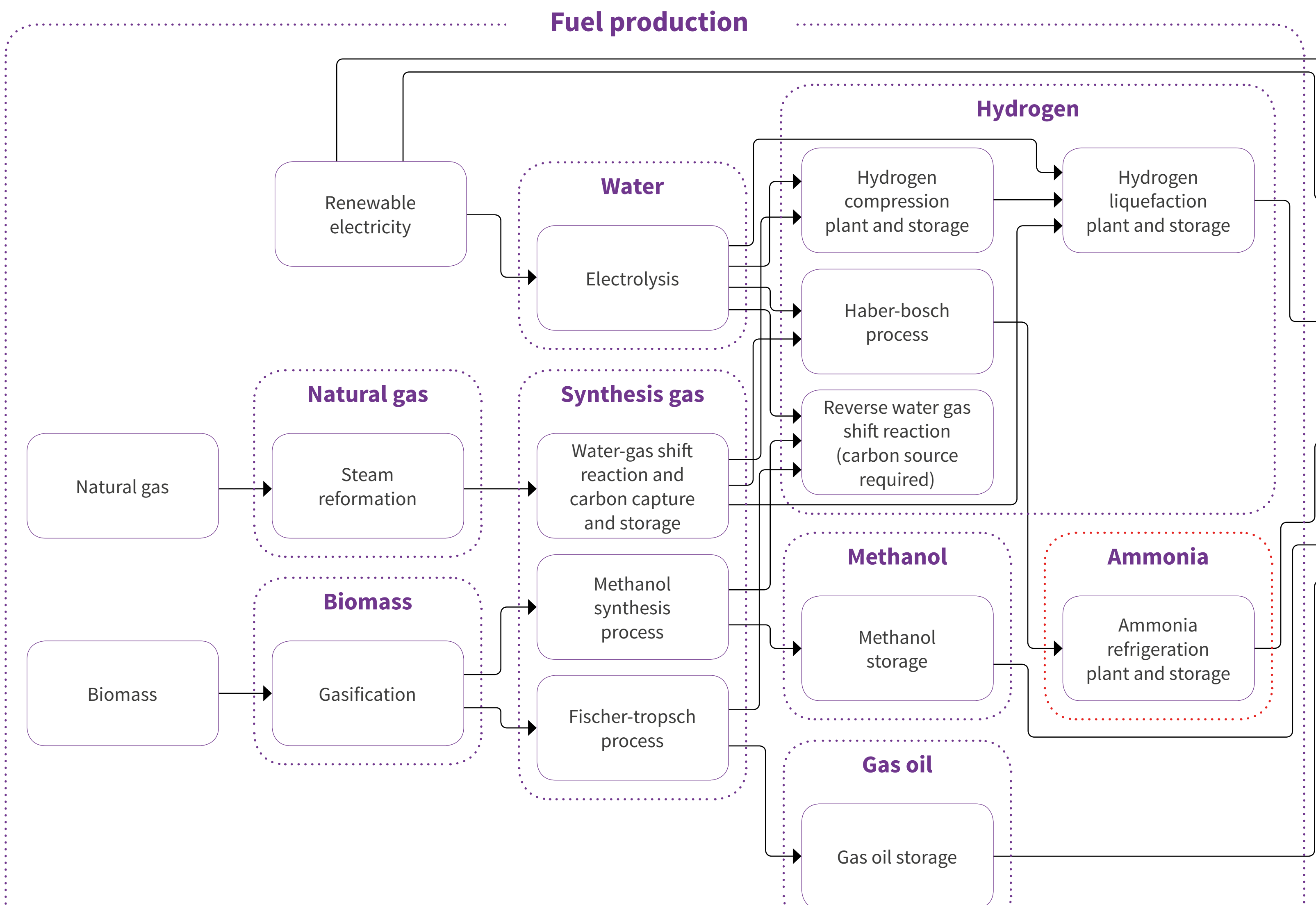


Figure 1 - Pathways diagram

Zero-carbon production cost estimates

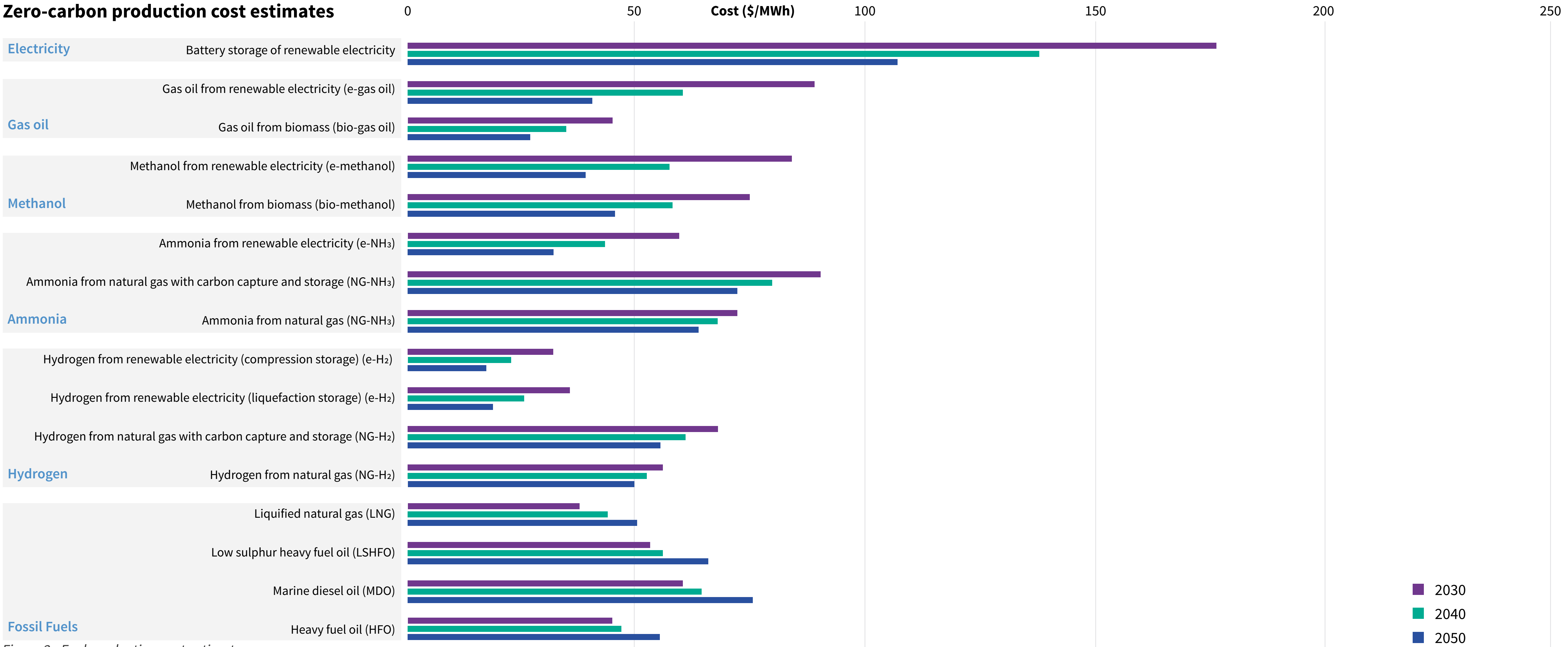


Figure 2 - Fuel production cost estimates

Figure 3 - Hydrogen production from renewable electricity (liquefaction storage) cost breakdown

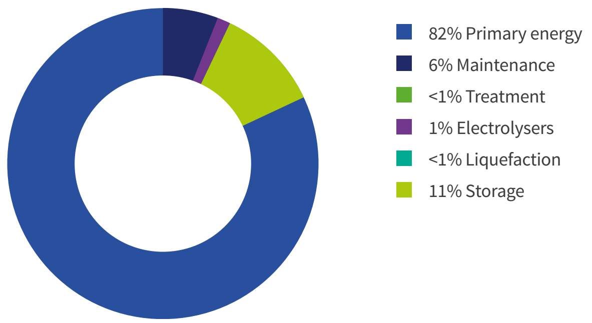


Figure 4 - Hydrogen production from renewable electricity (compression storage) cost breakdown

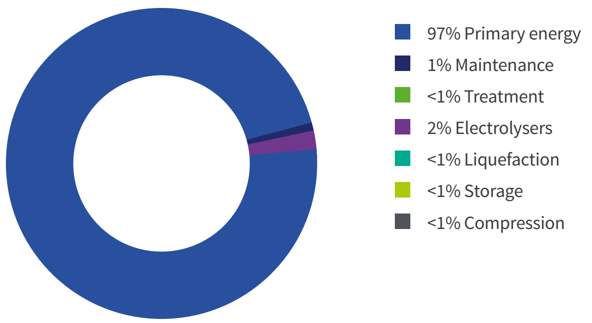


Figure 5 - Ammonia from renewable electricity cost breakdown

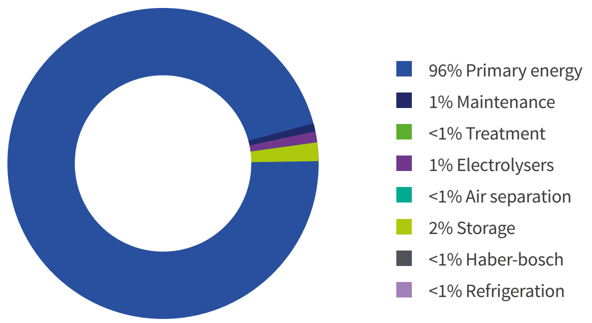


Figure 6 - Methanol from renewable electricity

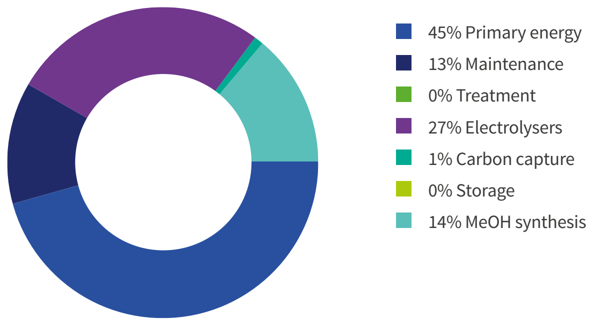


Figure 7- Gas oil from renewable electricity

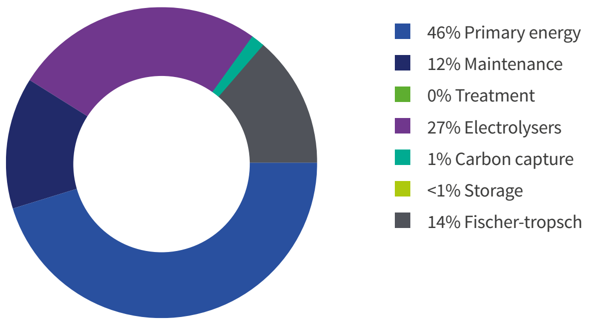
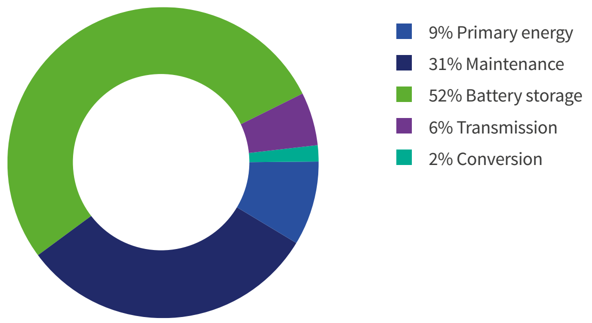


Figure 8 - Renewable electricity storage cost breakdown



Net emissions per tonne of fuel produced and consumed

Carbon dioxide (CO_2)

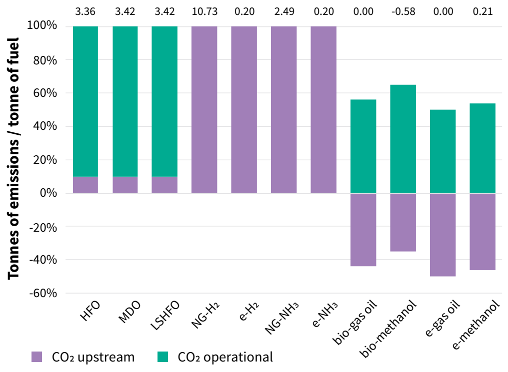


Figure 9 - Net carbon dioxide emissions

Methane (CH_4)

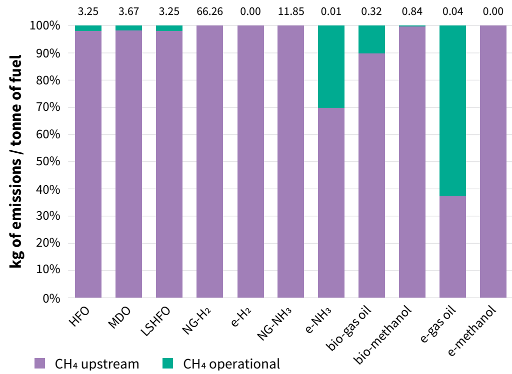


Figure 10 - Net methane emissions

Nitrous oxide (N_2O)

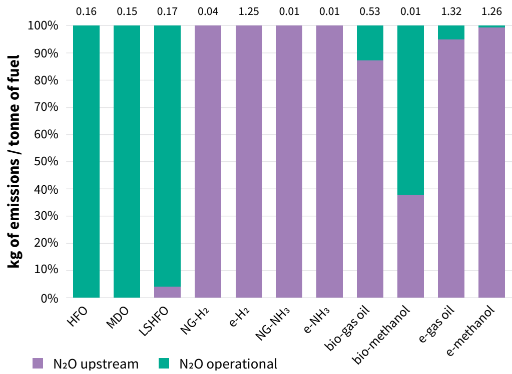


Figure 11 - Net nitrous oxide emissions

Oxides of nitrogen (NOx)

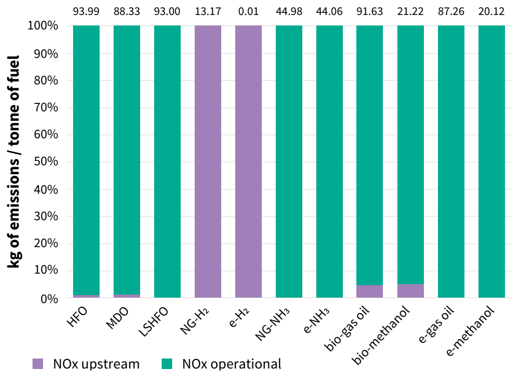


Figure 12 - Net oxides of nitrogen emissions

Oxides of sulphur (SOx)

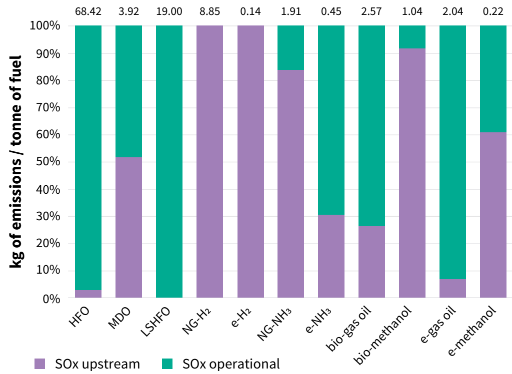


Figure 13 - Net oxides of sulphur emissions

Particulate matter (PM)

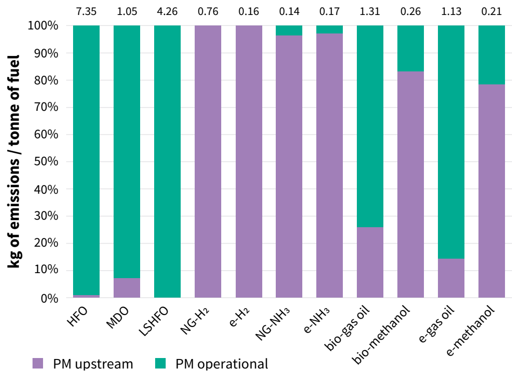


Figure 14 - Net particulate matter emissions

Zero-carbon fuel production and distribution

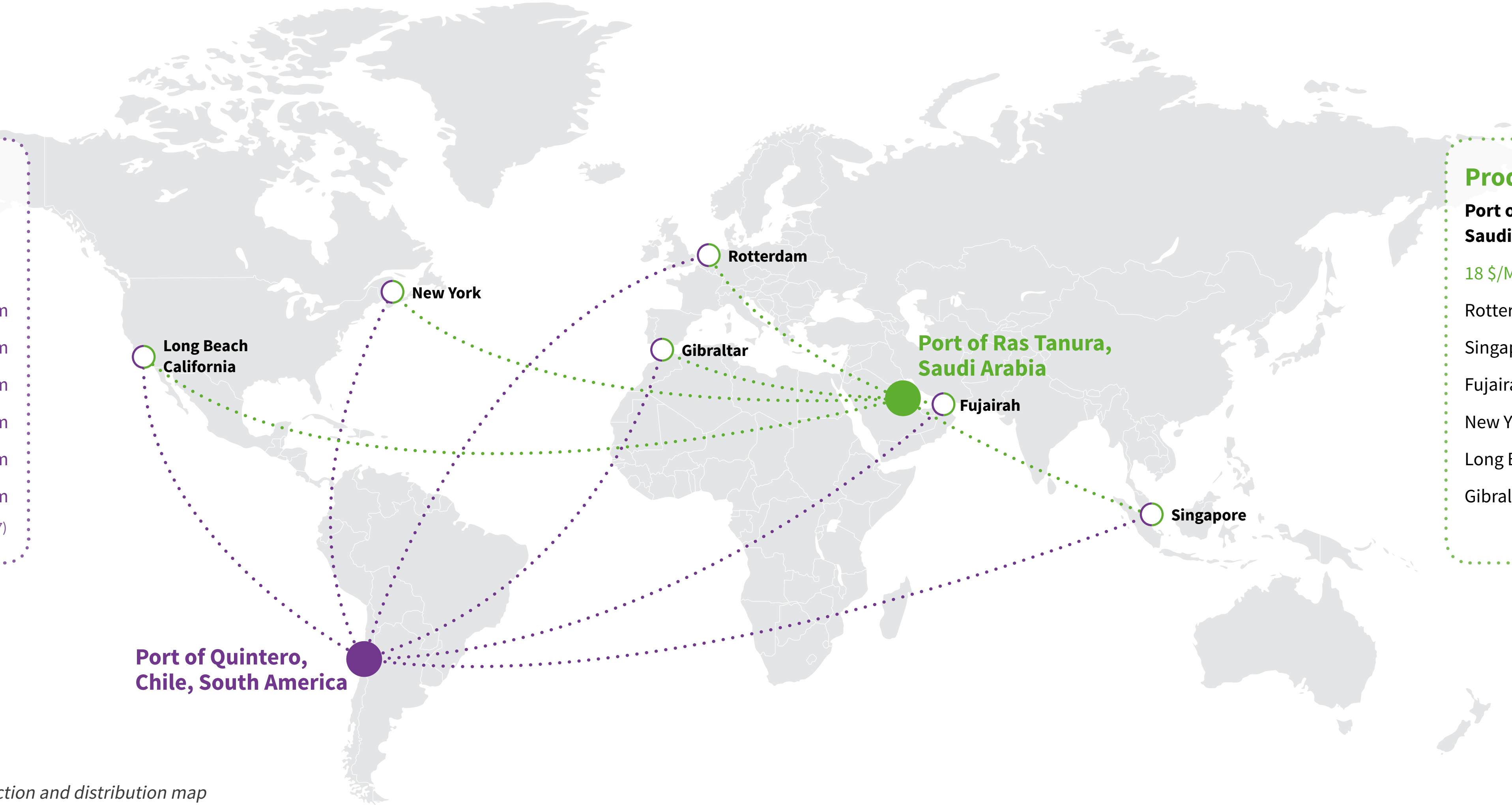
Production location

Port of Quintero, Chile, South America

21 $/MWh

Rotterdam	7465nm
Singapore	9985nm
Fujairah	9668nm
New York	4643nm
Long Beach, California	4803nm
Gibraltar	7002nm

(SeaRoutes 2017)



Production location

Port of Ras Tanura, Saudi Arabia

18 $/MWh

Rotterdam	6417nm
Singapore	3736nm
Fujairah	466nm
New York	8281nm
Long Beach, California	11393nm
Gibraltar	5097nm

(SeaRoutes 2017)

Figure 15 - Zero-carbon fuel production and distribution map

Hydrogen production pathways.

Hydrogen production

The hydrogen fuel pathways that are considered within this study are as indicated within Figure 15. The requisite primary energy sources for fuel production in this instance are natural gas or renewable electricity in combination with water, which may undergo conversion to hydrogen through a process of steam reformation and electrolysis respectively.

Although comparable to these hydrogen production methods, the conversion of biomass (waste materials) through gasification and water-gas shift reaction has not been included, assuming a restriction of such resources for the derivation of liquid fuels.

Two methods for storage of the fuel product following conversion have been considered, in a state corresponding to high pressure (700 bar) and atmospheric temperature or atmospheric pressure and low temperature (-252^{o}C), i.e. through compression or liquefaction. It has been assumed that the transportation, bunkering and onboard storage of the fuel would be undertaken exclusively whilst in a cryogenic liquid state, i.e. at atmospheric pressure and low temperature.

The cost of hydrogen as a fuel obtained through the steam reformation of natural gas and the electrolysis of water are specified as $1,000-$3,000 and $1,500-$3,000 respectively (International Energy Agency, 2017). These costs are composed of elements associated with the capital investment requirements of the production facility in addition to the fixed and variable operational expenses that are attributable to the production process.

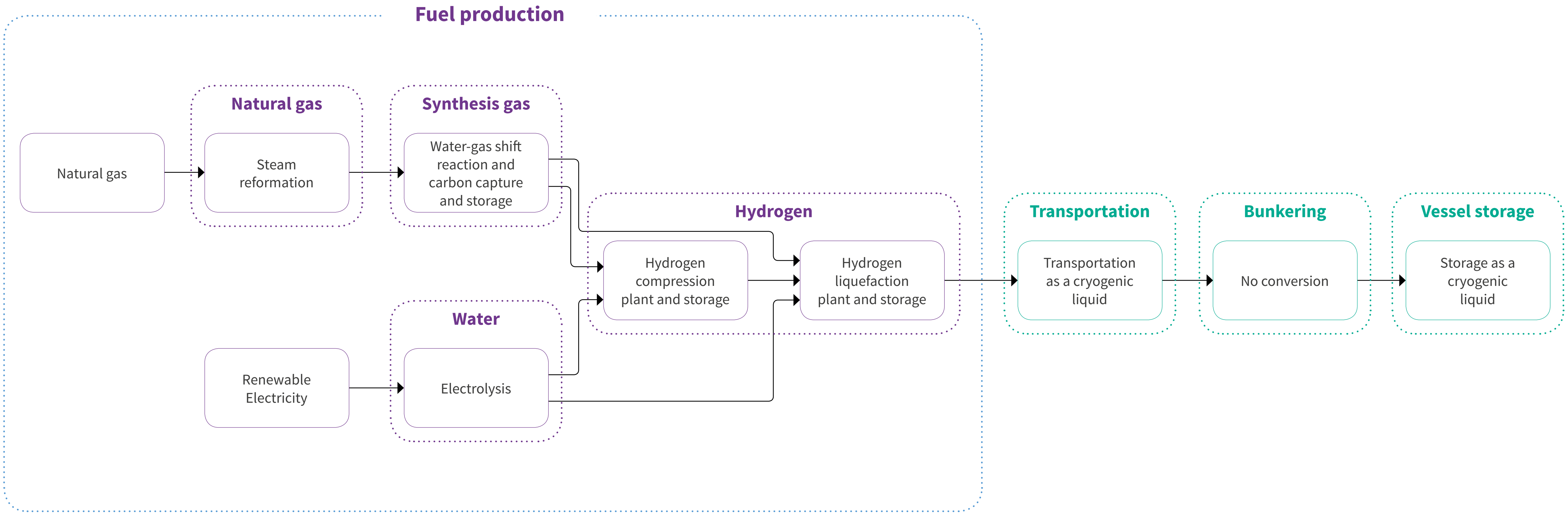


Figure 16 - Hydrogen production pathway

HYDROGEN PRODUCTION

(CONTINUED)

Steam reformation

In the case of hydrogen production through steam reformation, the operational expenses account for the maintenance costs of systems and equipment (fixed), the energy requirements of the process (variable) and the primary energy sources (natural gas) necessary for fuel production (variable). In this instance the price of natural gas has greater influence over the variable operational expenses than the price of electricity, suggesting that location of the fuel production facility is of minor significance. As such, an appropriate level of representation for the cost of hydrogen production typically associated with this process may be obtained through an average of the figures specified previously.

Electrolysis

In the case of hydrogen production through electrolysis, the operational expenses account for the maintenance costs of systems and equipment (fixed) and the energy requirements of the fuel production process (variable). In this instance the price of electricity has a singular influence over the variable operational expenses, suggesting that location of the fuel production facility is of primary importance when sources of renewable energy are under consideration (International Energy Agency, 2017). Therefore, calculation of the cost of hydrogen production is necessary to incorporate the location specific price of renewable electricity and thereby obtain an appropriate level of representation.

The geographical locations considered within the calculations for the cost of hydrogen production through electrolysis are South America and the Middle East, specifically the port of Quintero (Chile) and the port of Ras Tanura (Saudi Arabia) respectively.

These locations are representative of geographical regions in which a moderate renewable electricity generation potential exists, as indicated within Figure 17, ranking fifth and third respectively in reference to overall global capacity (International Energy Agency, 2017). In this context, the development of approximately 1.5% or 1.0% of these respective renewable electricity generation potentials would be required to accommodate the annual energy consumption of the global shipping fleet, of between 11 EJ/yr - 12 EJ/yr (Olmer, et al., 2017).

These locations are representative of regions in which there exists the potential for renewable electricity to be made available at a significantly reduced price by comparison to those with dissimilar geographical characteristics (International Energy Agency, 2017). The renewable electricity prices that have been assumed for these locations within this study are 21 $/MWh for South America and 18 $/MWh for the Middle East (IMarEST, 2018).

The requisite information and parameters for these calculations, concerning the capital expenses of the facility, the maintenance costs of systems and equipment and the energy requirements of the production process, are included below within Table 1 and Table 2. These parameters correspond to the individual stages of the fuel production process for hydrogen and have been obtained from various sources of literature, as indicated within the applicable data sources specification.

As a means of comparison, (Brynolf, et al., 2018) provide a variable range of between 20 €/MWh and 37 €/MWh for the average wholesale electricity price of the northern European region for the period 2015 to 2018.

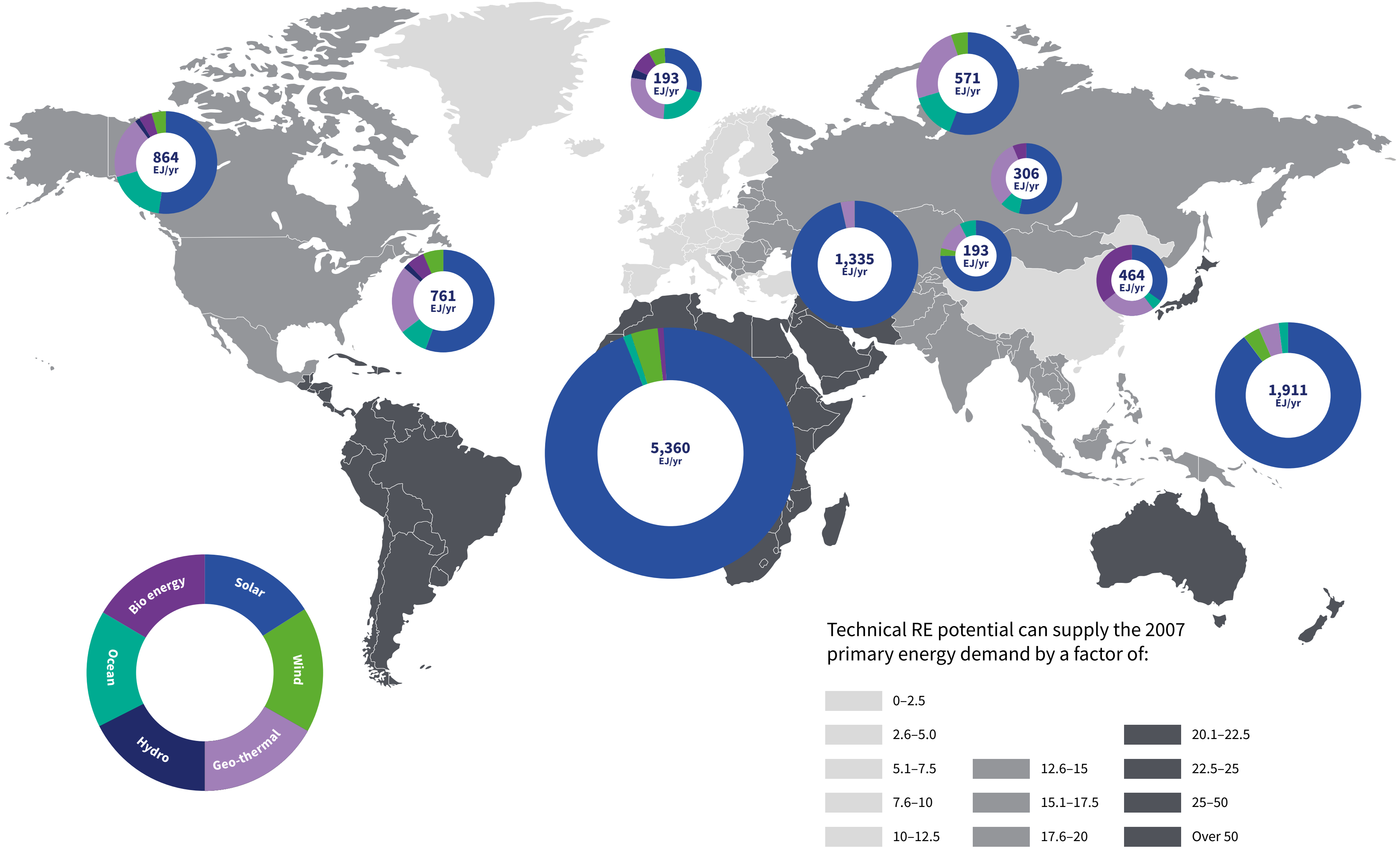


Figure 17 - Global renewable energy potential by geographical region (International Energy Agency, 2017)

HYDROGEN PRODUCTION
(CONTINUED)

Table 1 - Parameters for renewable electricity hydrogen production - liquefaction storage

Production stage	Capital expenditure	Operational expenditure	Stage efficiency	Energy requirements
Pre-treatment	2.23 (€/m^3) [a]	4.3% of Capex [a]	45% [a]	3 (kWh/m^3) [a]
Electrolysis	400 (€/kW) [b]	3% of Capex [a]	70% [b]	4.2 - 5.9 (kWh/m^3) [c]
Liquefaction	0.5 - 1.1 (€/kg) [d]	5% of Capex [e]	77% [f]	10.18 (kWh/kg) [g]
Storage	18 ($/kg) [h]			0.1% Boil-Off Per Day [h]

Data Sources: [a] (Fasihi, et al., 2016); [b] (International Energy Agency, 2017); [c] (Schmidt, et al., 2017); [d] (International Energy Agency, 2014); [e] (Syed, et al., 1998); [f] (Ni, 2006); [g] (Gardiner & Satyapal, 2009); [h] (National Renewable Energy Laboratory, 1998).

Table 2 - Parameters for renewable electricity hydrogen production - compression storage

Production stage	Capital expenditure	Operational expenditure	Stage efficiency	Energy requirements
Pre-treatment	2.23 (€/m^3) [a]	4.3% of Capex [a]	45% [a]	3 (kWh/m^3) [a]
Electrolysis	400 (€/kW) [b]	3% of Capex [a]	70% [b]	4.2 - 5.9 (kWh/m^3) [c]
Compression	0.63 - 1.3 (€/kg) [d]	0.01 - 0.05% of Capex [e]	94% [e]	2.85 (kWh/kg) [f]
Storage	0.015 (€/kWh) [g]			NaN
Liquefaction	0.5 - 1.1 (€/kg) [d]	5% of Capex [h]	77% [e]	10.18 (kWh/kg) [f]

Data Sources: [a] (Fasihi, et al., 2016); [b] (International Energy Agency, 2017); [c] (Schmidt, et al., 2017); [d] (International Energy Agency, 2014); [e] (Ni, 2006); [f] (Gardiner & Satyapal, 2009); [g] (Fasihi & Breyer, 2017); [h] (Syed, et al., 1998).

Production facility

The calculations for the fuel product costs of hydrogen are based on a production facility with an annual capacity of 500,000 tonnes per year. This capacity has been selected in an attempt to capture the potential benefits for capital expenditure that are associated with production at an increased volume; i.e. 'economies of scale'. In this instance the capacity selected is representative of the annual fuel consumption of approximately 33 container ships or 93 oil tankers with typical tonnage, power and range characteristics. An operational lifespan of 30 years' duration has been assumed for the fuel production facility, throughout which uniform repayment of the initial capital expenditure is expected in addition to a return rate equivalent to a 7% weighted average cost of capital.

A value of 0.8 has been assumed for the operation of the constituent systems and equipment, representing an annual processing time of 80% (7,008 hours) and corresponding to a scheduled downtime of 20% (1,752 hours). An operational lifespan of 75,000 hours has been used for the alkaline electrolysers, as provided within (Schmidt, et al., 2017), and has been included within the calculations in a manner assuming direct replacement for the operational lifespan of the fuel production facility.

Storage and transportation

The required fuel product storage capacity of the production facility has been assumed to correspond with 10% of the overall capacity, i.e. totalling 50,000t, intended for retention prior to scheduled transportation to primary bunkering locations. The locations considered as primary bunker locations for the purposes of this study are Rotterdam, Singapore, Fujairah, New York, Long Beach and Gibraltar. The transportation of the hydrogen fuel product is assumed to be undertaken by a vessel capable of the carriage of the total fuel production facility storage capacity in a single voyage, necessitating ten voyages on an annual basis.

Figure 17 summarises the distances from the production location to the primary bunkering locations for electro-hydrogen. Through use of these values an average figure for the voyage distance between the fuel production and primary bunker locations has been calculated for both the Middle East and South America alternatives.

There are two distinct types of electro-hydrogen production facilities that have been considered within this study, the variation of which being concerned with the state in which storage of the hydrogen fuel product is undertaken. This variation represents storage of the hydrogen fuel product in a liquefied state at atmospheric pressure and low temperature or alternatively in a compressed state at high pressure and atmospheric temperature.

To enable transportation in a liquefied state, direct loading of the fuel product onto the vessel is possible for the fuel production facility in which liquefaction and hydrogen storage in a liquefied state is undertaken. However, for the fuel production facility in which compression and hydrogen storage in a compressed state is undertaken an additional stage of liquefaction is required to carry out the further phase conversion of the fuel product. It would be necessary for the systems and equipment associated with this liquefaction stage to be capable of processing the total storage capacity of the fuel production facility at an appropriate rate for loading of the vessel.

In this instance a processing capacity of 50,000 tonnes per day has been considered for this additional liquefaction stage, to enable vessel loading to be undertaken within a period that is typical for such vessels (Croatian Shipbuilding, 2014), i.e. within 24 hours.

The results of the calculations are included below within Table 3 and Table 4, in which the capital expenditure, the fixed operational expenditure and the variable operational expenditure required for the fuel production facility are provided.

Table 3 - Financial requirements for renewable electricity hydrogen production - liquefaction storage

Production stage	Capital expenditure ($)	Fixed operational expenditure ($/y)	Variable operational expenditure ($/y)
Pre-treatment	2,149,515	92,429	2,104,246
Electrolysis	118,000,000	3,540,000	547,813,752
Liquefaction	84,189	4,209	128,902,597
Storage	9,000,000	45,000,000	128,903
Total	**129,233,704**	**48,636,638**	**678,949,498**

Table 4 - Financial requirements for renewable electricity hydrogen production - compression storage

Production stage	Capital expenditure ($)	Fixed operational expenditure ($/y)	Variable operational expenditure ($/y)
Pre-treatment	2,149,515	92,429	2,104,246
Electrolysis	118,000,000	3,540,000	547,813,752
Compression	101,554	30	29,561,170
Storage	34,869,000	10,461	NaN
Liquefaction	1,966,667	98,333	128,902,597
Total	**157,086,736**	**3,741,253**	**708,381,765**

HYDROGEN PRODUCTION EMISSIONS

The emissions that are attributable to the production of hydrogen through steam reformation of natural gas are provided within Table 5 (Spath & Mann, 2001). It has been assumed for the purposes of this study that no emissions are formed as a direct result of the production of hydrogen through the electrolysis of water using sources of renewable energy. However, as the location of the fuel production facility holds significant influence over the feasibility of hydrogen production in this manner, recognition and assignation of the transportation emissions is required.

As specified previously, the geographical locations of electro-hydrogen production that are considered within this study are South America and the Middle East, specifically the port of Quintero (Chile) and the port of Ras Tanura (Saudi Arabia) respectively. The locations that are considered as the primary bunker locations for electro-hydrogen distribution are Rotterdam, Singapore, Fujairah, New York, Long Beach and Gibraltar. The voyage distances assumed for transportation of electro-hydrogen from the port of Quintero are 7,465nm, 9,985nm, 9,688nm, 4,643nm, 4,803nm and 7,002nm respectively. Similarly, the voyage distances assumed for transportation of electro-hydrogen from the port of Ras Tanura by sea are 6,471nm, 3,736nm, 466nm, 8,281nm, 11,393nm and 5,097nm respectively (SeaRoutes, 2017). Through use of these values an average figure for the voyage distance between the proposed fuel production and primary bunker locations has been calculated for both the Middle East and South America geographical alternatives.

The transportation emissions have been calculated using these average distance values in combination with information provided within (Brynolf, et al., 2014) concerning the energy requirements for transportation and the combustion characteristics of propulsion machinery obtained from (Kristensen, 2012), (Moldanova, et al., 2010) and (International Maritime Organization, 2014). Through these calculations, figures corresponding to transportation from the Middle East and South America could be obtained, from which an average has been taken to represent the typical emissions attributable to the fuel product as a consequence of these transportation requirements.

The resultant emission values that are attributable to the production of hydrogen from natural gas and sources of renewable energy respectively are provided within Table 5, represented in differing scales of concentration per tonne of fuel production. The emissions for natural gas derived hydrogen correspond to those attributable to the production process, for which it has been assumed no additional transportation is required. In this instance it is assumed that the production of hydrogen from natural gas may be undertaken at the primary bunkering location, as the geographical location holds limited influence over feasibility. In contrast, the emissions for renewable energy derived hydrogen correspond to those attributable to the production process, assumed as zero, in combination with those attributable to the additional transportation that is required.

Table 5 - Hydrogen production emissions

Emission compound	Hydrogen production from natural gas	Hydrogen production from renewable electricity
Carbon dioxide CO_2 (t.em/t.fp)	10.73	0.2036
Methane CH_4 (g.em/t.fp)	66,260	3.762
Nitrous oxide N_2O (g.em/t.fp)	38.52	11.91
Oxides of nitrogen NO_X (kg.em/t.fp)	13.17	1.254
Oxides of sulphur SO_X (kg.em/t.fp)	8.854	0.1365
Particulate matter PM (g.em/t.fp)	758.0	162.3

Data Sources: NG-Hydrogen Production Emissions (Spath & Mann, 2001); Electro-Hydrogen Production Emissions (Brynolf, et al., 2014), (Kristensen, 2012), (Moldanova, et al., 2010) and (International Maritime Organization, 2014).

In order to estimate the cost of hydrogen as a fuel product, the additional costs as a consequence of CO_2 capture and storage and transportation of the fuel product are required. A further aspect that should be considered within the estimation of the hydrogen fuel product cost is the potential for reductions over time as a result of increased technology adoption and future development.

The additional cost of carbon capture and storage for the production of hydrogen from natural gas is specified within as $670 per tonne of fuel product within (International Energy Agency, 2017), corresponding with CO_2 emissions of 10.7 t.em/t.fp in accordance with (Spath & Mann, 2001). The application of this additional cost to the production cost of hydrogen through steam reformation of natural gas is necessary to emulate the cost of the fuel product when produced through this process in a CO_2 neutral manner. The additional cost for transportation of an electro-hydrogen fuel product is provided within (International Energy Agency, 2014), in which an average value of $165 per tonne is obtained from the specified range of $153 - $177 per tonne. The application of this additional cost to the production cost of hydrogen through the electrolysis of water is necessary to represent the location-dependent nature of fuel production in this manner.

An estimate of the fuel production cost reduction over time due to increased technology utilisation and future development is provided within (International Energy Agency, 2014) and (International Renewable Energy Agency, 2013), from which differentiated rates of cost reduction could be calculated. The differentiated rate calculated for the production of hydrogen through steam reformation of natural gas and in combination with carbon capture and storage corresponds approximately to a 0.6% and 1.2% annual cost reduction respectively (International Energy Agency, 2014). The differentiated rate calculated for the production of hydrogen using sources of renewable energy for the electrolysis of water corresponds approximately to a 4% annual cost reduction (International Renewable Energy Agency, 2013).

The fuel product cost estimates obtained through integration of the specified additional costs and application of the differentiated rates of reduction are included below within Table 6 for the alternative forms of hydrogen production considered within this study.

Table 6 - Hydrogen fuel product cost estimates

Year	NG-hydrogen ($/t)	NG&CCS-hydrogen ($/t)	Liq. electro-hydrogen ($/t)	Comp. electro-hydrogen ($/t)
2018	2,000	2,670	1,831	1,622
2030	1,861	2,276	1,196	1,067
2040	1,753	2,031	856	769
2050	1,651	1,837	628	570

Data Sources: Carbon Capture and Storage Costs (International Energy Agency, 2017), (Spath & Mann, 2001); Transportation Costs (International Energy Agency, 2014); Production Cost Reductions (International Energy Agency, 2014), (International Renewable Energy Agency, 2013).

AMMONIA

Ammonia production pathways.

Ammonia production

The ammonia fuel pathways that are considered within this study are as indicated within Figure 18. The requisite primary energy sources for fuel production in this instance are natural gas or renewable electricity in combination with water, which may undergo conversion to ammonia through steam reformation or electrolysis respectively in combination with a Haber-Bosch process.

A single method for storage of the fuel product following conversion has been considered, in a state corresponding to atmospheric pressure and low temperature (-33°C), i.e. through refrigeration. It has been assumed that the transportation, bunkering and onboard storage of the fuel product would be undertaken exclusively whilst in a refrigerated liquid state, i.e. at atmospheric pressure and low temperature.

The cost of ammonia as a fuel product obtained through the steam reformation of natural gas and the electrolysis of water are specified as $200-$600 and $400-$650 respectively within (International Energy Agency, 2017). These costs are comprised of capital investment requirements in addition to the fixed and variable operational expenses of the production process in a similar manner to that described previously for the production of hydrogen.

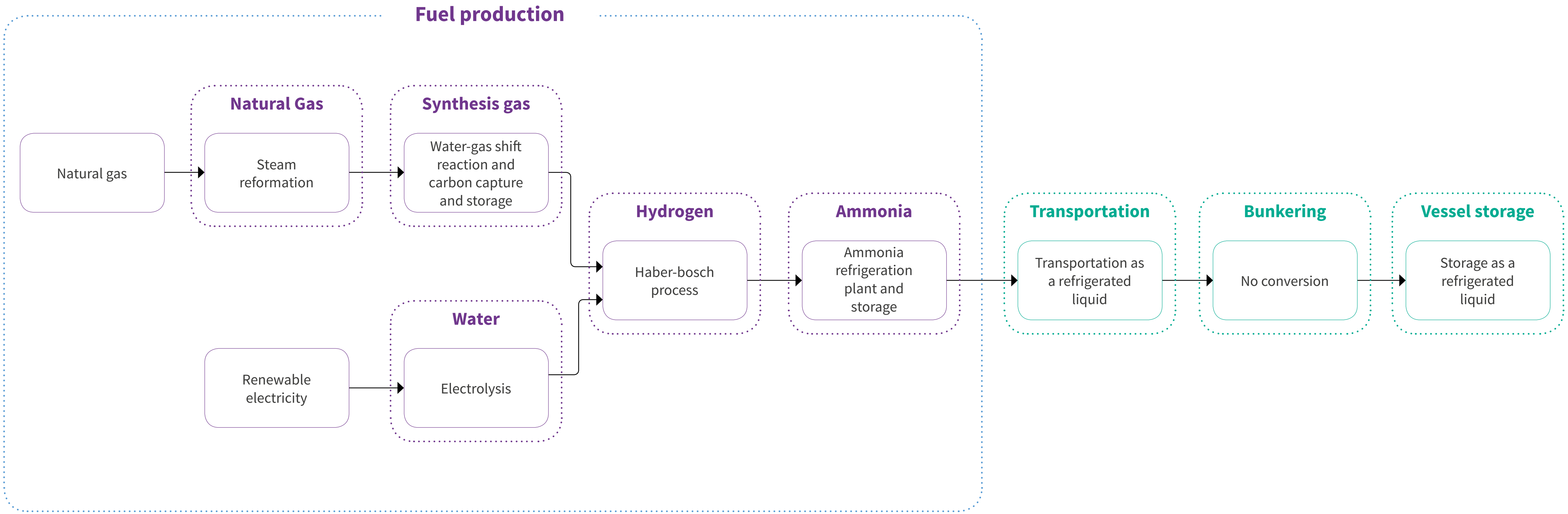


Figure 18 - Ammonia production pathways

Steam reformation versus electrolysis

In this instance the price of natural gas has greater influence over the variable operational expenses than the price of electricity for the production of ammonia through steam reformation, and as such the location of the fuel production facility is of minor significance. Correspondingly, the price of electricity has a singular influence over the variable operational expenses for the production of ammonia through electrolysis, and as a consequence the location of the fuel production facility is of primary importance (International Energy Agency, 2017). Therefore, an appropriate level of representation for the cost of ammonia production through steam reformation may be obtained through an average of the figures specified previously. However, to obtain an appropriate level of representation for the cost of ammonia production through electrolysis, calculation is necessary to incorporate the location-specific price of renewable electricity.

The geographical locations considered for the cost of ammonia production through electrolysis are as per those previously specified for hydrogen.

The requisite information and parameters in this instance, concerning the capital expenses of the facility, the maintenance costs of systems and equipment and the energy requirements of the production process, are included below within Table 7. These parameters correspond to the individual stages of the fuel production process for ammonia and have been obtained from various sources of literature, as indicated within the applicable data sources specification.

Table 7 - Parameters for renewable electricity ammonia production

<table>
<tr><th>Production stage</th><th>Capital expenditure</th><th>Operational expenditure</th><th>Stage efficiency</th><th>Energy requirements</th></tr>
<tr><td>Pre-treatment</td><td>2.23 (€/m^3) [a]</td><td>4.3% of Capex [a]</td><td>45% [a]</td><td>3 (kWh/m^3) [a]</td></tr>
<tr><td>Electrolysis</td><td>400 (€/kW) [b]</td><td>3% of Capex [a]</td><td>70% [b]</td><td>4.2 - 5.9 (kWh/m^3) [c]</td></tr>
<tr><td>Air separation</td><td>7.29 ($/kg) [d]</td><td>4% of Capex [d]</td><td>71.25% [d]</td><td>4.5 (kW/kg) [d]</td></tr>
<tr><td>Haber-Bosch</td><td>13 ($/kg) [d]</td><td>4% of Capex [d]</td><td>73.4 - 81.8% [d]</td><td>0.46 - 1.32 (kWh/kg) [e]</td></tr>
<tr><td>Refrigeration</td><td rowspan="2">0.7 ($/kg) [d]</td><td rowspan="2">3% of Capex [d]</td><td rowspan="2">85% [d]</td><td>0.03788731 (kWh/kg) [e]</td></tr>
<tr><td>Storage</td><td>0.1% Boil-off per day [d]</td></tr>
</table>

Data Sources: [a] (Fasihi, et al., 2016); [b] (International Energy Agency, 2017); [c] (Schmidt, et al., 2017); [d] (Morgan, 2013); [e] (Bartels, 2008).

Production facility

The calculations for the fuel product costs of ammonia are based on a production facility with similar characteristics to those of the hydrogen production facility described previously, which includes: an annual production capacity of 500,000 tonnes per year (representing the annual fuel consumption of 5 container ships or 15 oil tankers); a facility operational lifespan of 30 years; a weighted average cost of capital of 7 percent; a facility utilisation rate of 0.8 (International Energy Agency, 2017); an electrolyser lifespan of 75,000 hours (Schmidt, et al., 2017); and a facility storage capacity of 50,000 tonnes. The locations considered as primary bunker locations in this instance are also as per those specified previously, with transportation assumed to be similarly undertaken by a vessel with a capacity that corresponds to the fuel production facility storage capacity, i.e. 50,000t per scheduled voyage.

The results of the calculations are included below within Table 8, in which the capital expenditure, the fixed operational expenditure and the variable operational expenditure required for the fuel production facility are provided.

Table 8 - Financial requirements for renewable electricity ammonia production

Production stage	Capital expenditure ($)	Fixed operational expenditure ($/y)	Variable operational expenditure ($/y)
Pre-treatment	234,678	10,091	103,133
Electrolysis	20,951,911	628,557	138,955,752
Air separation	534,710	21,388	50,645,078
Haber-Bosch	1,159,389	46,376	11,182,345
Refrigeration	62,429	1,873	434,590
Storage	35,000,000	1,050,000	435
Total	**57,943,117**	**1,758,285**	**201,321,333**

Ammonia production emissions

The emissions that are attributable to the production of ammonia through steam reformation of natural gas are provided within (Spath & Mann, 2001), (Wood & Cowie, 2004) and (Environmental Protection Agency, 1993) and are shown within Table 9. To maintain consistency with the assumptions made in relation to the production of electro-hydrogen, it has been assumed that no emissions are formed as a direct result of the production of electro-ammonia. However, as the location of the fuel production facility holds significant influence over the feasibility of ammonia production in this manner, recognition and assignation of the transportation emissions is required.

The geographical locations of electro-ammonia production and those that are considered for distribution of the fuel product are as per those specified previously for electro-hydrogen, for which the transportation voyage distances (SeaRoutes, 2017) are retained. The transportation emissions for electro-ammonia have been calculated in a manner consistent with that adopted for electro-hydrogen, using average distance values in combination with information provided within (Brynolf, et al., 2014), (Kristensen, 2012), (Moldanova, et al., 2010) and (International Maritime Organization, 2014). Through these calculations figures corresponding to transportation from the Middle East and South America could be obtained, from which an average has been taken to represent the typical emissions attributable to the fuel product as a consequence of these transportation requirements.

The resultant emission values that are attributable to the production of ammonia from natural gas and sources of renewable energy respectively are provided within Table 9, represented in differing scales of concentration per tonne of fuel production. The emissions for natural gas-derived ammonia correspond to those attributable to the production process, for which it has been assumed no additional transportation is required. In this instance it is assumed that the production of ammonia from natural gas may be undertaken at the primary bunkering location, as the geographical location holds limited influence over feasibility. In contrast, the emissions for renewable energy-derived ammonia correspond to those attributable to the production process, assumed as zero, in combination with those attributable to the additional transportation that is required.

Table 9 - Ammonia production emissions

Emission compound	Ammonia production from natural gas	Ammonia production from renewable electricity
Carbon dioxide CO_2 (t.em/t.fp)	2.487	0.2036
Methane CH_4 (g.em/t.fp)	11,850	3.762
Nitrous oxide N_2O (g.em/t.fp)	6.840	11.91
Oxides of nitrogen NO_X (kg.em/t.fp)	2.180	1.254
Oxides of sulphur SO_X (kg.em/t.fp)	1.601	0.1365
Particulate matter PM (g.em/t.fp)	130.7	162.3

Data Sources: NG-Ammonia Production Emissions (Spath & Mann, 2001), (Wood & Cowie, 2004), (Environmental Protection Agency, 1993); Electro-Ammonia Production Emissions (Brynolf, et al., 2014), (Kristensen, 2012), (Moldanova, et al., 2010) and (International Maritime Organization, 2014).

Ammonia production cost emissions

In order to estimate the cost of ammonia as a fuel product in a manner consistent with that undertaken for hydrogen, the additional costs as a consequence of CO_2 capture and storage and transportation of the fuel product are required. Similarly, the potential for reductions over time as a result of increased technology adoption and future development should be considered within the estimation of the electro-ammonia cost to allow for comparison with the alternative fuel products.

The additional cost of carbon capture and storage for the production of ammonia from natural gas is $153 per tonne of fuel product (International Energy Agency, 2017), corresponding with CO_2 emissions of 2.5 t.em/t.fp in accordance with (Spath & Mann, 2001) and (Wood & Cowie, 2004). The additional cost for transportation of an electro-ammonia fuel product is provided within (International Energy Agency, 2017), in which an average value of $50 per tonne is obtained from the specified range of $40 - $60 per tonne.

In order to estimate the fuel production cost reduction over time due to increased technology utilisation and future development, application of differentiated rates in a manner consistent to that specified previously is necessary. The differentiated rate calculated for the production of ammonia through steam reformation of natural gas and in combination with carbon capture and storage corresponds approximately to a 0.6% and 1.2% annual cost reduction respectively (International Energy Agency, 2014). The differentiated rate calculated for the production of ammonia using sources of renewable energy for the electrolysis of water corresponds approximately to a 4% annual cost reduction (International Renewable Energy Agency, 2013).

The fuel product cost estimates obtained through integration of the specified additional costs and application of the differentiated rates of reduction are included below within Table 10 for the alternative forms of ammonia production considered within this study.

Table 10 - Ammonia fuel product cost estimates

Year	NG-ammonia ($/t)	NG&CCS-ammonia ($/t)	Electro-ammonia ($/t)
2018	400	553	468
2030	372	467	309
2040	351	414	223
2050	330	373	166

Data Sources: Carbon Capture and Storage Costs (International Energy Agency, 2017), (Spath & Mann, 2001), (Wood & Cowie, 2004), (Environmental Protection Agency, 1993); Transportation Costs (International Energy Agency, 2017); Production Cost Reductions (International Energy Agency, 2014), (International Renewable Energy Agency, 2013).

Methanol production pathways.

Methanol production

The methanol fuel pathways that are considered within this study are as indicated within Figure 19. The requisite primary energy sources for fuel production in this instance are biomass or renewable electricity in combination with water, which may undergo conversion to methanol through gasification or electrolysis with carbon capture respectively in combination with a methanol synthesis process.

A single method for storage of the fuel product following conversion has been considered, in a state corresponding to atmospheric pressure and temperature, i.e. in a natural state. It has been assumed that the transportation, bunkering and onboard storage of the fuel product would be undertaken exclusively whilst in a natural state, i.e. at atmospheric pressure and temperature.

The cost of methanol as a fuel product obtained through the gasification of biomass and electrolysis in combination with carbon capture are specified as \$177-\$944 and \$602-\$1,062 respectively within (International Renewable Energy Agency, 2013). These costs are composed of capital investment requirements in addition to the fixed and variable operational expenses of the production process in a similar manner to that described previously for the production of hydrogen.

METHANOL PRODUCTION
(CONTINUED)

Gasification versus electrolysis

In this instance the price of biomass has greater influence over the variable operational expenses than the price of electricity for the production of methanol through gasification, and as such the location of the fuel production facility is of minor significance. Correspondingly, the price of electricity has a singular influence over the variable operational expenses for the production of methanol through electrolysis, and as a consequence the location of the fuel production facility is of primary importance (International Energy Agency, 2017). Therefore, an appropriate level of representation for the cost of methanol production through gasification may be obtained through an average of the figures specified previously. In this regard it is assumed that cultivation of the biomass required for the production of methanol in this manner is undertaken within the geographical region of the fuel production facility. However, to obtain an appropriate level of representation for the cost of methanol production through electrolysis, calculation is necessary to incorporate the location-specific price of renewable electricity.

The geographical locations considered within the calculations for the cost of methanol production through electrolysis are as per those specified previously for the production of hydrogen ammonia.

The requisite information and parameters in this instance, concerning the capital expenses of the facility, the maintenance costs of systems and equipment and the energy requirements of the production process, are included below within Table 11. These parameters correspond to the individual stages of the fuel production process for methanol and have been obtained from various sources of literature, as indicated within the applicable data sources specification.

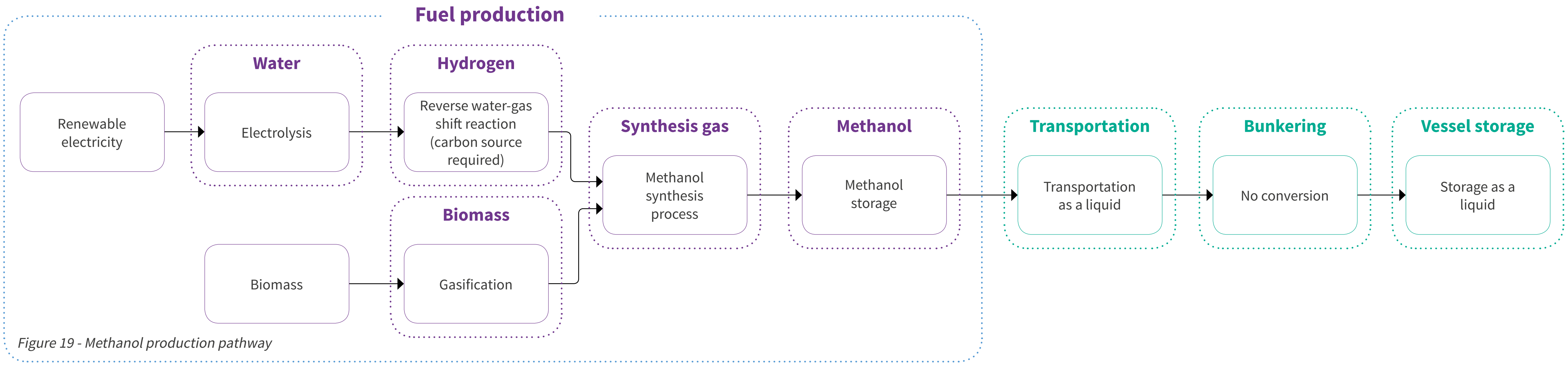


Figure 19 - Methanol production pathway

Table 11 - Parameters for renewable electricity methanol production

Production stage	Capital expenditure	Operational expenditure	Stage efficiency	Energy requirements
Pre-treatment	2.23 (€/m^3) [a]	4.3% of Capex [a]	45% [a]	3 (kWh/m^3) [a]
Electrolysis	400 (€/kW) [b]	3% of Capex [a]	70% [b]	4.2 - 5.9 (kWh/m^3) [c]
Carbon capture	228 (€/t) [d]	4% of Capex [d]	94% [d]	225 (kWh/t) [d]
MeOH synthesis	726 (€kW) [d]	4% of Capex [d]	80.3% [d]	216 (kWh/t) [d]
Storage	0.144 ($/kg) [e]	0.01 - 0.05% of Capex	100%	NaN

Data Sources: [a] (Fasihi, et al., 2016); [b] (International Energy Agency, 2017); [c] (Schmidt, et al., 2017); [d] (Fasihi & Breyer, 2017); [e] (Amirkhas, et al., 2006).

Production facility

The calculations for the fuel product costs of ammonia are based on a production facility with similar characteristics to those of the hydrogen production facility described previously, which includes: an annual production capacity of 500,000 tonnes per year (representing the annual fuel consumption of 5 container ships or 15 oil tankers); a facility operational lifespan of 30 years; a weighted average cost of capital of 7 percent; a facility utilisation rate of 0.8 (International Energy Agency, 2017); an electrolyser lifespan of 75,000 hours (Schmidt, et al., 2017); and a facility storage capacity of 50,000 tonnes. The locations considered as primary bunker locations in this instance are also as per those specified previously, with transportation assumed to be similarly undertaken by a vessel with a capacity that corresponds to the fuel production facility storage capacity, i.e. 50,000t per scheduled voyage.

The results of the calculations are included below in Table 12, in which the capital expenditure, the fixed operational expenditure and the variable operational expenditure required for the fuel production facility are provided.

Table 12 - Financial requirements for renewable electricity methanol production

Production stage	Capital expenditure ($)	Fixed operational expenditure ($/y)	Variable operational expenditure ($/y)
Pre-treatment	429,903	18,486	116,168
Electrolysis	929,840,000	27,895,200	156,518,215
Carbon capture	35,031,250	1,401,250	3,407,314
MeOH synthesis	488,208,583	19,528,343	2,622,665
Storage	7,200,000	2,160	0
Total	**1,460,709,736**	**48,845,439**	**162,664,362**

The emissions that are attributable to the production of methanol through gasification of biomass are provided within (Brynolf, et al., 2014) and derived in accordance with the life-cycle reduction potentials of (DNV GL - Maritime, 2018), as shown within Table 13. To maintain consistency with the assumptions made in relation to the production of electro-hydrogen, it has been assumed that no emissions are formed as a direct result of the production of electro-methanol. However, as the location of the fuel production facility holds significant influence over the feasibility of methanol production in this manner, recognition and assignation of the transportation emissions is required.

The geographical locations of electro-methanol production and those that are considered for distribution of the fuel product are as per those specified previously for electro-hydrogen, for which the transportation as shown in Figure 17 voyage distances (SeaRoutes, 2017) are retained. The transportation emissions for electro-methanol have been calculated in a manner consistent with that used for electro-hydrogen, using average distance values in combination with information provided within (Brynolf, et al., 2014), (Kristensen, 2012), (Moldanova, et al., 2010) and (International Maritime Organization, 2014). Through these calculations figures corresponding to transportation from the Middle East and South America could be obtained, from which an average has been taken to represent the typical emissions attributable to the fuel product as a consequence of these transportation requirements.

The resultant emission values that are attributable to the production of methanol from biomass and sources of renewable energy respectively are provided within Table 13, represented in differing scales of concentration per tonne of fuel production. The emissions for biomass-derived methanol correspond to those attributable to the production process, for which it has been assumed no additional transportation is required. In this instance it is assumed that the production of methanol from biomass may be undertaken at the primary bunkering location, as the geographical location holds limited influence over feasibility. In contrast, the emissions for renewable energy-derived methanol correspond to those attributable to the production process, assumed as -1.46 t.em/t.fp for CO_2 (Fasihi & Breyer, 2017) and zero for the remaining compounds, in combination with those attributable to the additional transportation that is required.

Table 13 - Methanol production emissions

Emission compound	Methanol production from biomass	Methanol production from renewable electricity
Carbon dioxide CO_2 (t.em/t.fp)	-0.7900	-1.256
Methane CH_4 (g.em/t.fp)	835.8	3.762
Nitrous oxide N_2O (g.em/t.fp)	4.378	11.91
Oxides of nitrogen NO_X (kg.em/t.fp)	1.114	1.254
Oxides of sulphur SO_X (kg.em/t.fp)	0.9552	0.1365
Particulate matter PM (g.em/t.fp)	218.9	162.3

Data Sources: Bio-Methanol Production Emissions (Brynolf, et al., 2014); Electro-Methanol Production Emissions (Fasihi & Breyer, 2017); (Brynolf, et al., 2014), (Kristensen, 2012), (Moldanova, et al., 2010) , (International Maritime Organization, 2014) and DNV GL - Maritime, 2018.

Methanol production cost estimates

In order to estimate the cost of methanol as a fuel product in a manner consistent with that undertaken for hydrogen, the additional costs as a consequence of transportation of the fuel product are required. Similarly, the potential for reductions over time as a result of increased technology adoption and future development should be considered within the estimation of the electro-methanol cost to allow for comparison with the alternative fuel products.

The additional cost for transportation of an electro-methanol fuel product is derived from (American Journal of Transportation, 2018), from which an average value of $17 per tonne is obtained from the indicated range of $6 - $38 per tonne. The differentiated rate calculated for the production of methanol through gasification of biomass and electrolysis of water corresponds approximately to a 2.5% and 4% annual cost reduction respectively (International Renewable Energy Agency, 2013).

The fuel product cost estimates obtained through integration of the specified additional costs and application of the differentiated rates of reduction are included below within Table 14 for the alternative forms of methanol production considered within this study.

Table 14 - Methanol fuel product cost estimates

Year	Bio-methanol ($/t)	Electro-methanol ($/t)
2018	561	742
2030	416	466
2040	324	318
2050	252	219

Data Sources: Transportation Costs (American Journal of Transportation, 2018); Production Cost Reductions (International Energy Agency, 2014), (International Renewable Energy Agency, 2013).

Gas oil production pathways.

Gas oil production

The gas oil fuel pathways that are considered within this study are as indicated within Figure 20. The requisite primary energy sources for fuel production in this instance are biomass or renewable electricity in combination with water, which may undergo conversion to gas oil through gasification or electrolysis with carbon capture respectively in combination with the Fischer-Tropsch process.

A single method for storage of the fuel product following conversion has been considered, in a state corresponding to atmospheric pressure and temperature, i.e. in a natural state. It has been assumed that the transportation, bunkering and onboard storage of the fuel product would be undertaken exclusively whilst in a natural state, i.e. at atmospheric pressure and temperature.

The cost of gas oil as a fuel product obtained through the gasification of biomass and electrolysis in combination with carbon capture are specified as $628-$816 and $673-$1,944 within (Festel, et al., 2014) and (Brynolf, et al., 2018) respectively. These costs are comprised of capital investment requirements in addition to the fixed and variable operational expenses of the production process in a similar manner to that described previously for the production of hydrogen.

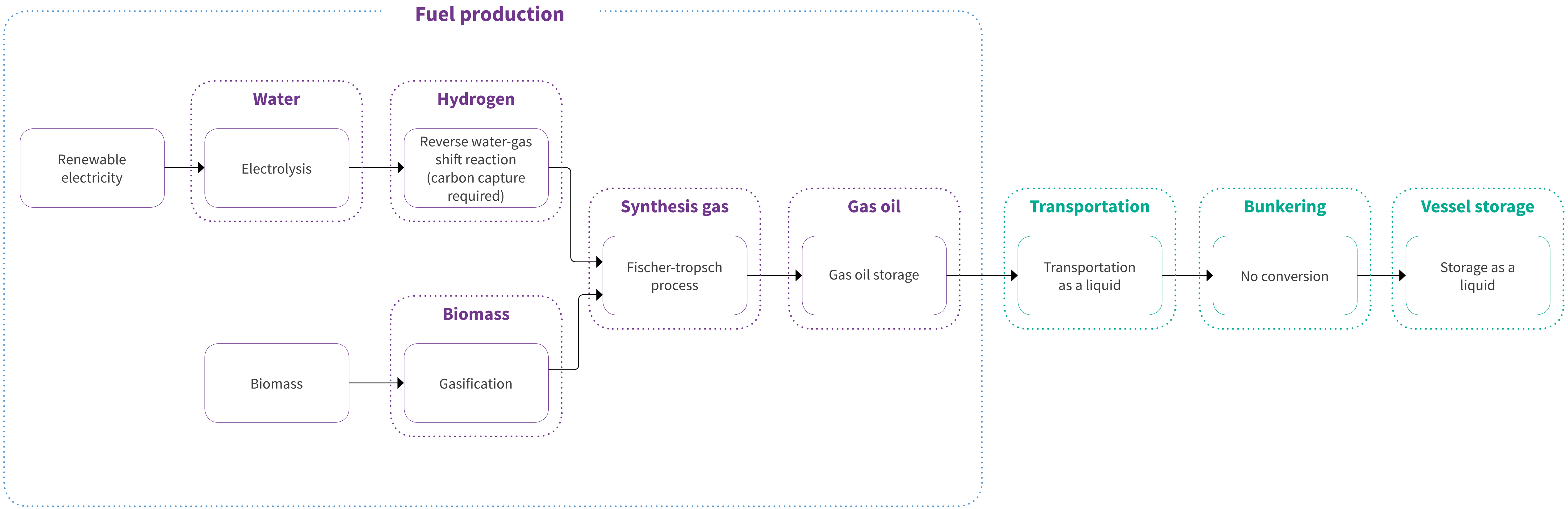


Figure 20 - Gas oil production pathway

Gasification verses electrolysis

In this instance the price of biomass has greater influence over the variable operational expenses than the price of electricity for the production of gas oil through gasification, and as such the location of the fuel production facility is of minor significance. Correspondingly, the price of electricity has a singular influence over the variable operational expenses for the production of gas oil through electrolysis, and as a consequence the location of the fuel production facility is of primary importance (International Energy Agency, 2017). Therefore, an appropriate level of representation for the cost of gas oil production through gasification may be obtained through an average of the figures specified previously. In this regard it is assumed that cultivation of the biomass required for the production of gas oil in this manner is undertaken within the geographical region of the fuel production facility. However, to obtain an appropriate level of representation for the cost of gas oil production through electrolysis, calculation is necessary to adequately incorporate the location-specific price of renewable electricity.

The geographical locations considered within the calculations for the cost of gas oil production through electrolysis are as per those specified previously for the production of hydrogen, i.e. as shown in Figure 17. South America and the Middle East. The renewable electricity prices that have been assumed for these locations are also as per those used previously, specifically 21 $/MWh for South America and 18 $/MWh for the Middle East (IMarEST, 2015).

The requisite information and parameters in this instance, concerning the capital expenses of the facility, the maintenance costs of systems and equipment and the energy requirements of the production process, are included below within Table 15. These parameters correspond to the individual stages of the fuel production process for gas oil and have been obtained from various sources of literature, as indicated within the applicable data sources specification.

Table 15 - Parameters for renewable electricity gas oil production

Production stage	Capital expenditure	Operational expenditure	Stage efficiency	Energy requirements
Pre-treatment	2.23 (€/m^3) [a]	4.3% of Capex [a]	45% [a]	3 (kWh/m^3) [a]
Electrolysis	400 (€/kW) [b]	3% of Capex [a]	70% [b]	4.2 - 5.9 (kWh/m^3) [c]
Carbon capture	228 (€/t) [d]	4% of Capex [d]	94% [d]	225 (kWh/t) [d]
Hydrocarbons	60,000 (€/bpd) [a]	3% of Capex [a]	57.5% [a]	258 (kWh/t) [a]
Storage	0.14 ($/kg) [e]	0.01 - 0.05% of Capex [e]	100% [e]	NaN

Data Sources: [a] (Fasihi, et al., 2016); [b] (International Energy Agency, 2017); [c] (Schmidt, et al., 2017); [d] (Fasihi & Breyer, 2017); [e] (DNV-GL Maritime, 2018).

Production facility

The calculations for the fuel product costs of gas oil are based on a production facility with similar characteristics to those of the hydrogen production facility described previously, which includes: an annual production capacity of 500,000 tonnes per year (representing the annual fuel consumption of 11 container ships or 30 oil tankers); a facility operational lifespan of 30 years; a weighted average cost of capital of 7 percent; a facility utilisation rate of 0.8 (International Energy Agency, 2017); an electrolyser lifespan of 75,000 hours (Schmidt, et al., 2017); and a facility storage capacity of 50,000 tonnes. The locations considered as primary bunker locations in this instance are also as per those specified previously, with transportation assumed to be similarly undertaken by a vessel with a capacity that corresponds to the fuel production facility storage capacity, i.e. 50,000t per scheduled voyage.

The results of the calculations are included below within Table 16, in which the capital expenditure, the fixed operational expenditure and the variable operational expenditure required for the fuel production facility are provided.

Table 16 - Financial requirements for renewable electricity gas oil production

Production stage	Capital expenditure ($)	Fixed operational expenditure ($/y)	Variable operational expenditure ($/y)
Pre-treatment	1,416,643	60,916	373,468
Electrolysis	3,064,067,936	91,922,038	515,768,781
Carbon capture	117,118,793	4,684,752	11,391,557
Hydrocarbons	1,598,682,318	47,960,470	6,043,120
Storage	9,669,473	2,901	0
Total	**4,790,955,163**	**144,631,077**	**533,576,926**

Gas oil production emissions

The emissions that are attributable to the production of gas oil through gasification of biomass are provided within (Brynolf, et al., 2014) and derived in accordance with the life-cycle reduction potentials of (DNV GL - Maritime, 2018), as shown within Table 17. To maintain consistency with the assumptions made in relation to the production of electro-hydrogen, it has been assumed that no emissions are formed as a direct result of the production of electro-gas oil.

However, as the location of the fuel production facility holds significant influence over the feasibility of gas oil production in this manner, recognition and assignation of the transportation emissions is required.

The geographical locations of electro-gas oil production and those that are considered for distribution of the fuel product are as per those specified previously for electro-hydrogen, for which the transportation voyage distances (SeaRoutes, 2017) are retained.

The transportation emissions for electro-gas oil have been calculated in a manner consistent with that used for electro-hydrogen, as per Figure 17 using average distance values in combination with information provided within (Brynolf, et al., 2014), (Kristensen, 2012), (Moldanova, et al., 2010) and (International Maritime Organization, 2014).

Through these calculations figures corresponding to transportation from the Middle East and South America could be obtained, from which an average has been taken to represent the typical emissions attributable to the fuel product as a consequence of these transportation requirements.

The resultant emission values that are attributable to the production of gas oil from biomass and sources of renewable energy respectively are provided within Table 17, represented in differing scales of concentration per tonne of fuel production. The emissions for biomass-derived gas oil correspond to those attributable to the production process, for which it has been assumed no additional transportation is required. In this instance it is assumed that the production of gas oil from biomass may be undertaken at the primary bunkering location, as the geographical location holds limited influence over feasibility. In contrast, the emissions for renewable energy-derived gas oil correspond to those attributable to the production process, assumed as -3.53 t.em/t.fp for CO_2 (Fasihi, et al., 2016) and zero for the remaining compounds, in combination with those attributable to the additional transportation that is required.

Table 17 - Gas oil production emissions

Emission compound	Gas oil production from biomass	Gas oil production from renewable electricity
Carbon dioxide CO_2 (t.em/t.fp)	-2.410	-3.330
Methane CH_4 (g.em/t.fp)	286.8	3.762
Nitrous oxide N_2O (g.em/t.fp)	460.6	11.92
Oxides of nitrogen NO_X (kg.em/t.fp)	484.8	1.254
Oxides of sulphur SO_X (kg.em/t.fp)	0.6703	0.1365
Particulate matter PM (g.em/t.fp)	341.1	162.3

Data Sources: Bio-Gas Oil Production Emissions (Zhou, et al., 2017); Electro-Gas Oil Production Emissions (Fasihi, et al., 2016), (Brynolf, et al., 2014), (Kristensen, 2012), (Moldanova, et al., 2010) and (International Maritime Organization, 2014); (DNV GL - Maritime, 2018).

Gas oil production cost estimates

In order to estimate the cost of gas oil as a fuel product in a manner consistent with that undertaken for hydrogen, the additional costs as a consequence of transportation of the fuel product are required. Similarly, the potential for reductions over time as a result of increased technology adoption and future development should be considered within the estimation of the electro-gas oil cost to allow for comparison with the alternative fuel products.

The additional cost for transportation of an electro-gas oil fuel product is derived from (American Journal of Transportation, 2018), from which an average value of $8 per tonne is obtained from the indicated range of $5 - $13 per tonne. The differentiated rate calculated for the production of gas oil through gasification of biomass and electrolysis of water corresponds approximately to a 2.5% and 4% annual cost reduction respectively (International Renewable Energy Agency, 2013).

The fuel product cost estimates obtained through integration of the specified additional costs and application of the differentiated rates of reduction are included below within Table 18 for the alternative forms of gas oil production considered within this study.

Table 18 - Gas oil fuel product cost estimates

Year	Bio-gas oil ($/t)	Electro-gas oil ($/t)
2018	722	1,707
2030	535	1,059
2040	417	713
2050	324	480

Data Sources: Transportation Costs (American Journal of Transportation, 2018); Production Cost Reductions (International Energy Agency, 2014), (International Renewable Energy Agency, 2013).

Electricity production pathways.

Electricity production

The electricity pathways that are considered within this study are as indicated within Figure 21. The requisite primary energy sources for production in this instance is renewable electricity in combination with some form of battery storage, which is assumed to be situated within the port facility that is to function as the intended vessel-charging location.

The inclusion of a battery storage facility within this pathway is considered necessary to enable charging of a vessel to be undertaken in a comparable timeframe to that required for bunkering of an equivalent fuel product. The storage of renewable electricity in this manner would also function as a grid stabilisation mechanism during periods of excess production and provide justification for the construction of the additional generation capacity required by such a facility.

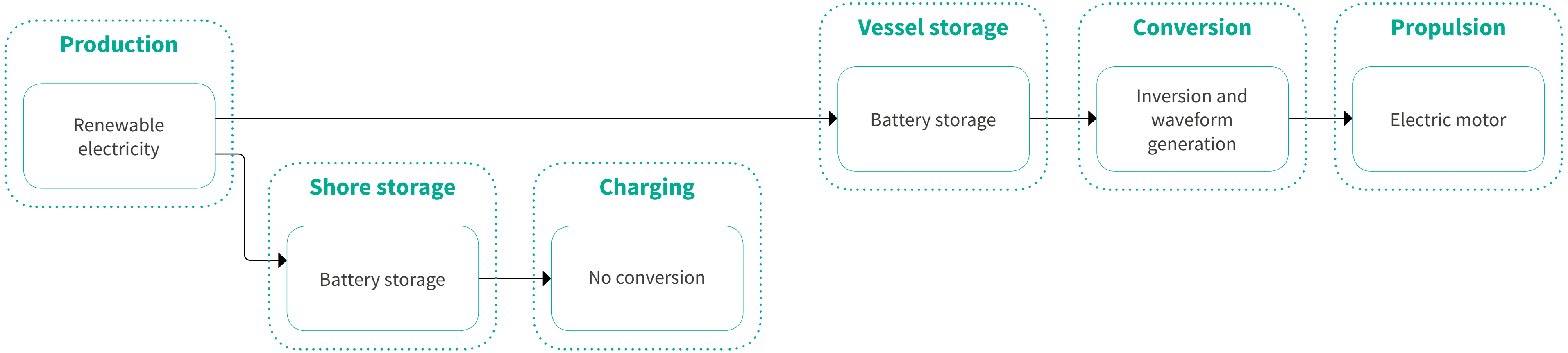


Figure 21 - Electricity production pathway

The geographical locations considered within the calculations for the cost of electricity storage in this manner are as per those specified previously for the production of hydrogen, i.e. South America and the Middle East. The renewable electricity prices that have been assumed for these locations are also as per those used previously, specifically 21 $/MWh for South America and 18 $/MWh for the Middle East (IMarEST, 2015).

The requisite information and parameters in this instance, concerning the capital expenses of the facility, the maintenance costs of systems and equipment and the energy requirements of the storage process, are included below within Table 19. These parameters correspond to the individual stages of the storage process for renewable electricity and have been obtained from various sources of literature, as indicated within the applicable data sources specification.

Table 19 - Parameters for renewable electricity storage

Production stage	Capital expenditure	Operational expenditure	Stage efficiency	Energy requirements
Transmission	0.612 (€/kW/km) [a]	0.0075 (€/kW/km) [a]	98.4% per 1000km [a]	NaN
Conversion	180 (€/kW) [a]	1.8 (€/kW) [a]	98.6% [a]	NaN
Battery storage	150 (€/kWh) [b]	6% of Capex [b]	90% [b]	NaN

Data Sources: [a] (Fasihi & Breyer, 2017); [b] (Fasihi, et al., 2016).

Storage facility

The calculations for the product costs of renewable electricity are based on a battery storage facility with similar characteristics to those of the hydrogen production facility described previously, which includes: a facility operational lifespan of 30 years; a weighted average cost of capital of 7 percent; and a facility utilisation rate of 0.8 (International Energy Agency, 2017). In a dissimilar yet consistent manner to the fuel production facility calculations conducted previously, an operational lifespan of 15 years has been used for the batteries, as provided within (Fasihi, et al., 2016). This has been included within the calculations assuming direct replacement of the batteries for the operational lifespan of the electricity storage facility, corresponding with the assumptions made in reference to the electrolysers for the fuel production facilities. An additional assumption in this instance is the availability of an appropriate form and capacity of renewable electricity generation at a distance of no more than 1,000km from the location of the battery storage facility.

There are two distinct categorisations of facility that have been considered within this study, the variation of which is concerned with the scale of electricity storage undertaken, and hence the types of vessel intended for its utilisation. This variation represents an electricity storage facility with the capacity to accommodate domestic inland, coastal and short sea vessels, of relatively small tonnage and limited range requirements, or larger vessels that are more representative of deep-sea shipping respectively.

The coastal vessel electricity storage facility is scaled to correspond with the tonnage, power and range characteristics of electric vessels that are available at present, such as that developed by the HH Ferries Group and ABB (Lambert, 2017) or the Hangzhou Modern Ship Design and Research Company (Lambert, 2017). In this instance a electrical capacity of 50MWh is assumed for the storage facility, representing a capability to accommodate the requirements of approximately ten vessels of this type and corresponding with an annual electricity consumption of 18.3GWh.

The deep-sea vessel electricity storage facility is scaled to correspond with the tonnage and power characteristics of a typical bulk carrier (Doskocz, 2012) and oil/product tanker (Croatian Shipbuilding, 2014) with a range of approximately 1,000nm; or greater with a corresponding reduction in the former parameters. In this instance an electrical capacity of 4.5GWh is assumed for the storage facility, representing a capability to accommodate the requirements of approximately two vessels of this type and corresponding with an annual electricity consumption of 1.6TWh.

The results of the calculations are included below within Table 20 and Table 21, in which the capital expenditure, the fixed operational expenditure and the variable operational expenditure required for the storage facility are provided.

Table 20 - Financial requirements for renewable electricity storage - coastal vessels

Production stage	Capital expenditure ($)	Fixed operational expenditure ($/y)	Variable operational expenditure ($/y)
Transmission	2,350,781	28,809	NaN
Conversion	691,406	6,914	NaN
Battery storage	22,125,000	1,327,500	388,818
Total	**25,167,187**	**1,363,233**	**388,818**

Table 21 - Financial requirements for renewable electricity storage - deep-sea vessels

Production stage	Capital expenditure ($)	Fixed operational expenditure ($/y)	Variable operational expenditure ($/y)
Transmission	206,331,832	2,528,576	NaN
Conversion	60,685,833	606,858	NaN
Battery storage	1,941,946,650	116,516,799	34,127,205
Total	**2,208,964,315**	**119,652,233**	**34,127,205**

Electricity production cost estimates

In order to estimate the cost of the renewable electricity storage in a manner consistent with that undertaken for the previous fuel products, the potential for reductions over time as a result of increased technology adoption and future development should be similarly considered. The differentiated rate calculated for the storage of renewable electricity in the form of batteries corresponds to an approximate 2.5% annual cost reduction, which is assumed to be consistent with that applicable to production of fuel from biomass resources (International Renewable Energy Agency, 2013).

The storage cost estimates obtained through application of the differentiated rate of reduction are included below within Table 22 for the form of renewable electricity storage that is considered within this study.

Table 22 - Renewable electricity storage cost estimates

Year	Battery electricity ($/MWh)
2018	239
2030	177
2040	138
2050	107

Data source: (International Renewable Energy Agency, 2013)

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