Deliverable WP1: Offshore Reuse Potential for Existing Gas Infrastructure in a Hydrogen Supply Chain

As part of the project "Gas Infrastructure Opportunities for a Hydrogen Supply Chain"

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Rev. No.: 4 (Final) Date: 08/02/2019

No distribution (confidential)

Abstract

The EU mitigation targets have inspired North sea countries to start significant offshore wind investment in the North sea. This study focuses on the Netherlands continental shelf, where, according to some projections, by 2050 as much as 60GW capacity may have been installed. Given the relatively high costs and lead times to transport the offshore wind power to shore and further on to its final destination via electricity cables, one increasingly recognizes that for socio-economic reasons and to benefit most of the wind energy, it may be a valid option to offshore convert part of the wind power into hydrogen, and use either the existing gas grid or dedicated hydrogen infrastructure to transport this renewable energy to its onshore destination. These green hydrogen flows may be combined with blue hydrogen generated to grow towards considerable volumes, although this aspect was not explicitly included in the modelling.

All this raises the issue which technically feasible and accepted hydrogen transport mode will be optimal under varying conditions from a cost perspective. With the help of a dedicated excel model the issue was addressed for 5 hydrogen transport modes to be operational during 2020-60.

In the first two modes either hydrogen is transported to shore via an existing grid by admixing it with conventional natural gas flows (but not separating it later on), or 100% hydrogen is transported via reused redundant gas pipelines assumed to be available (in time). In both cases levelised costs of transport[1] over an about 100km distance were comparable and small: some 0.01 EUR/kg.

In the second set of modes, either hydrogen was again admixed and transported via the existing gas grid, but now separated once onshore, or was transported to shore via a new dedicated hydrogen pipeline. The second option of these turned out to be superior due to the relatively high share of separation costs in overall transport mode costs (levelised costs of this option some 0.05 EUR/kg), but the less so with smaller hydrogen volumes and distance to shore. Levelised costs of admixing the hydrogen and separating it again onshore were found to be in the order of 0.36 EUR/kg. A final option including offshore methanation turned out to be extremely costly and therefore not feasible.

[1] The levelized cost of transport describes the net present value of the unit-cost of transported energy (LCOE) over the project lifetime. The LCOE can be taken as an indicator for the average price the transporting party must receive in a market for the project to break even.

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1. Introduction

The Netherlands, along with each of the 55 countries that signed the Paris Agreement[2], have made the pledge to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius compared to pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. Hence, these countries have submitted Nationally Determined Contributions (NDCs) expressing their national targets set by the Paris agreement. Among many climate change efforts, current challenges to reduce greenhouse gas emissions have to cope with reducing conventional energy consumption. Meanwhile energy demand driven by developing countries will significanly grow. Therefore, much attention and efforts are increasingly being put on hydrogen, as it is a promising energy carrier that can replace conventional fuels in a myriad of ways, drastically decreasing local pollution as well as greenhouse gas emissions when it is produced from renewable resources.

On a global scale, hydrogen production these days ranges between 600-720 billion Nm^3/year, 80 billion of which is accounted for by the European Union [1], and it is continuously growing at a rate of 5-6% per year. Just about 50% of the global hydrogen production is currently produced by means of steam methane reforming (SMR), using natural gas as feedstock, while only around 3-4% is produced without direct use of fossil resources [2].

The Northern Netherlands and the adjacent North Sea region, are locations to develop low-emission green hydrogen production, because of: large-scale green electricity production (mainly offshore wind); the proximity to large industrial energy demand; as well as existing oil & gas infrastructure which could be (partly) reused to transport green hydrogen. According to estimates stated in the TKI Hydrogen Roadmap [3], the potential demand for hydrogen in the Netherlands by 2050 might increase to about 14 Mton of hydrogen per year, although this estimate has been criticised for being at the high side of the spectrum.

Green hydrogen is usually produced by using electrolysis fed by offshore wind electricity with either offshore or onshore conversion. Previous research has shown that, in theory, hydrogen production will be more (cost)-efficient if conversion is located as close as possible to the primary source of input. In this study, offshore conversion and transport of hydrogen is presented as a viable alternative to transport energy by means of electricity to shore, if only because it could alleviate grid congestion and grid expansion challenges of feeding large quantities of wind electricity in the onshore power grid.

In the report *The future of the North Sea. The North Sea in 2030 and 2050: a scenario study* [4], a series of scenarios has been developed to assess the energy potential of the North Sea, and more specifically

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[2] https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement

of the Dutch Continental Shelf, in the years 2030 and 2050. They show that by 2030, an installed offshore wind power capacity in the range of 7.5-15 GW is feasible, which will continue to grow to 22-60 GW by 2050.

All in all, the potential benefits of a hydrogen-based economy are being recognised to different degrees by national governments and supranational institutions, although the pathways and techno-economic advancement to achieve such benefits remain a matter of discussion. The development of electrolysers that produce economically and technologically competitive hydrogen is a crucial prerequisite for the successful introduction of hydrogen as the fuel of the future. Other factors are also vital for a successful transition to a hydrogen economy, in particular the availability of infrastructure for transporting and storing hydrogen. Gaseous hydrogen is already transported over several thousand kilometres of pipelines in North America.

Nowadays, hydrogen producers typically own dedicated hydrogen pipelines themselves. These pipelines are strategically located where large hydrogen users are concentrated, such as petroleum refineries, chemical plants and steel production facilities. The expenses associated with the energy costs required to move the hydrogen between producers and consumers is mostly internalised in the hydrogen production costs. Regulated transport tariffs, known from the natural gas transport business, do not exist. However, the experience from natural gas pipeline operations can be used to assess the energy required to transport hydrogen through pipelines.

The costs of such transportation depend considerably on possible reallocation of existing gas infrastructure, or whether the construction of new hydrogen dedicated pipelines is needed. Reused pipelines can provide a low-cost option for point-to-point delivery of large volumes of hydrogen. By contrast, significant up-front costs may incur by the installation of new dedicated pipelines, which, given the current demand for hydrogen, could pose a limit on the expansion of such hydrogen infrastructure.

There are many different options to transport hydrogen molecules over long distances, e.g. from offshore generation hubs to the mainland. One of the objectives of this study is to determine the tipping point at which moment one transport scenario is preferable over another. Such analysis is important, especially regarding the option of re-using existing infrastructure, since the opportunity of re-use forgoes when infrastructure enters the decommissioning phase. The focus of this study and the modelling efforts is to determine and assess the techno-economic parameters of offshore hydrogen transportation, given a selection of transportation methods and taking into account varying distances and hydrogen volumes. The research questions are:

What are the most important techno-economic parameters for different offshore hydrogen transportation options ?

How do the different offshore hydrogen transportation options relate to each other from a cost point of view, also with regard to varying transport capacities and distances?

After the system boundaries of the research were defined, a series of scenarios (chapter 2) were developed in order to test the parameters of different transportation modes, and to conclude which scenario could provide under what conditions the most economically feasible way to transport hydrogen. Chapter 3 and 4 discuss the technological and economic parameters of the various transport techniques in more detail. The study outcome is translated into a model using MS-Excel software, via which, at the different variables and parameters, the user can visualise and ultimately compare the results of transporting hydrogen under the conditions of five selected scenarios. The results are presented in chapter 5 by way of a dynamic graph showing the relation between transport distance and costs (in time) for varying production volumes per scenario.

2. Approach

2.1. System boundaries

There is a variety of ways to transport hydrogen produced at offshore locations to the mainland where all demand is located. However, options that are included in this study are limited to the ones dealing with gaseous transport of hydrogen and methane e.g. produced from synthesizing hydrogen and carbon dioxide [3].

Figure 1 highlights the system boundaries in more detail, starting at the physical point of offshore produced hydrogen (output of installed wind and electrolyser capacity), including the potential conversion to methane, required on- and offshore compression, transportation of the molecules in gaseous form via a pipeline, and finally ending at an onshore delivery point (e.g. a gas treatment facility or a connection to the onshore distribution grid). The volume of hydrogen to be transported via the offshore infrastructure is expected to be determined by the offshore capacity of hydrogen production, which in turn is affected: by the offshore wind scenarios, the development of an onshore hydrogen economy, and the availability of existing infrastructure. In order to decrease the dependence on these developments the analysis focuses on the transport systems only.

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[3] For further explanation see section 3.

To compare the different transportation options, a series of scenarios is developed, each describing the transport options with particular boundary conditions for the most important technical parameters such as design pressure levels. Furthermore, the content of the study is limited to the extent that only applications with a high technology readiness level (TRL) and preferably proven technologies are included. To accommodate the system boundaries shown in Figure 1, the model has to operate with exogenous variables. They enter the model as fixed/'given' information, and affect the endogenous variables. The volume of hydrogen and distance are fixed and the same for each scenario in order to be able to compare the various transportsystems.

Various aspects are, for reasons of simplicity, left outside the scope of this project, but affect the outcomes of the analysis significantly. The potential for market uptake varies strongly between the commodities transported in the various scenarios, especially since a transparent hydrogen market (which includes aspects such as purity and pressure) has not evolved yet. Hence, if the potential for market uptake would be included another transport scenario is used, than the one indicating the lowest cost without including market uptake. . The study focuses on similar point-to-point transport cases of hydrogen and therefore on the greater routing flexibility that could be offered by new pipelines, since new pipelines do not have to follow the same itinerary as the existing pipeline network.

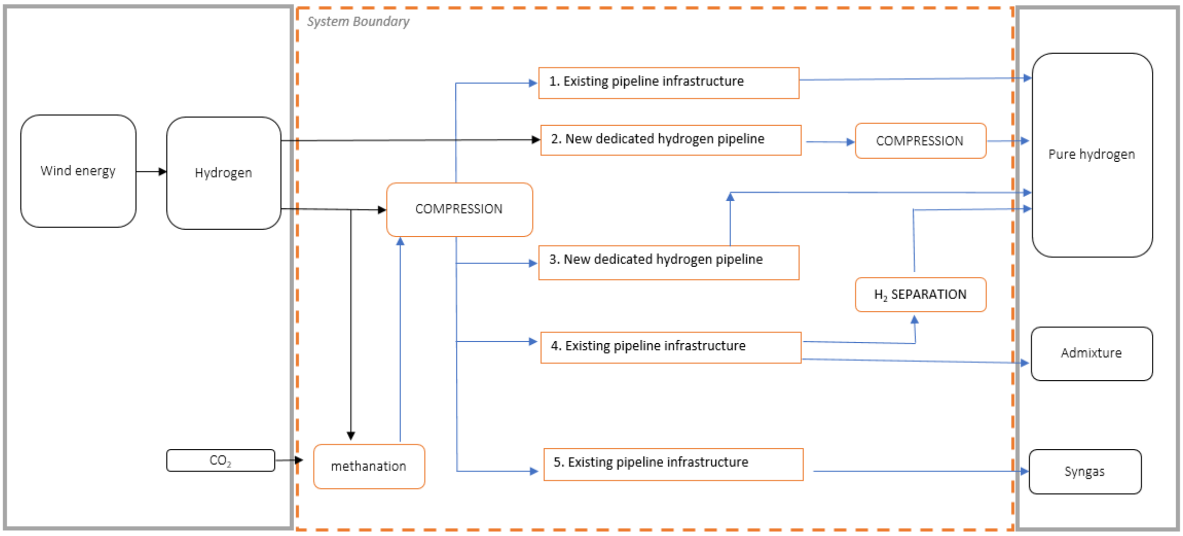

Figure 1 - System Boundaries

The calculation tool developed fulfils the requirements of a diversified economic analysis, as well as the requirements defined by the commissioning organisation, namely that the model should be able to calculate results with varying hydrogen volumes and transportation distances. Thus, no specific locations are considered. This is an important requirement since the potential for offshore hydrogen production will grow with the rollout of offshore wind generation so that assessing different hydrogen transport systems for changing volumes of offshore hydrogen production may be preferable. It is the purpose of the model to allow for highlighting the optimal transportation option for particular capacities and distances, and especially to identify turning points at which one scenario becomes preferable over another. The main requirements for the model are summarized in Table 1.

Table 1: Model requirements

Specification	
Hydrogen volume	The model should be able to highlight preferable transportation options with regard to hydrogen volume. For instance, new, dedicated pipelines might be more cost-efficient at larger hydrogen volumes, whereas admixing might be a preferred solution when smaller volumes of hydrogen are considered.
Transportation distance	The model should be able to highlight preferable transportation options with regard to distance. For instance, the economic benefits of reusing existing pipelines, assuming this is technically possible, may increase with increasing distance.
Maximum admixture of hydrogen in the existing natural gas flow (reuse of infrastructure)	The model should be able to adjust the admixed volumes of hydrogen in such a way that the accepted limit of hydrogen volume percentage in the existing natural gas flow will not be exceeded.
Maximum volume of gas that can be processed offshore	The offshore gas treatment plant located on O&G platforms is limited to the volumes of gas it can process. This limit should not be exceeded.
CO_2 sources	As mentioned in the description of system boundaries. CO_2 is expected to be available at the offshore production location. Hence, compression, transportation and capture costs (depending on source) are externally determined and need to enter the model as exogenous variables.
LCoE (transport)	The model needs to show costs of transported energy. It comprises the system costs (within the system boundaries) that are divided by the quantity of energy transported. This should be the comparable parameter for the various scenarios.
Sensitivity analysis	The model shall include the possibility to execute a sensitivity analysis based on changing CAPEX and OPEX parameters, distances and hydrogen production volumes.

Taking these specifications into consideration, the information flows of the model are shown below in Figure 2. The MS-Excel software allows the user to visualise and ultimately compare the results of transporting hydrogen in five designated scenarios. This result is eventually presented by way of a dynamic graph showing the relation between transport distance and costs (in time) for the varying production volumes of each scenario.

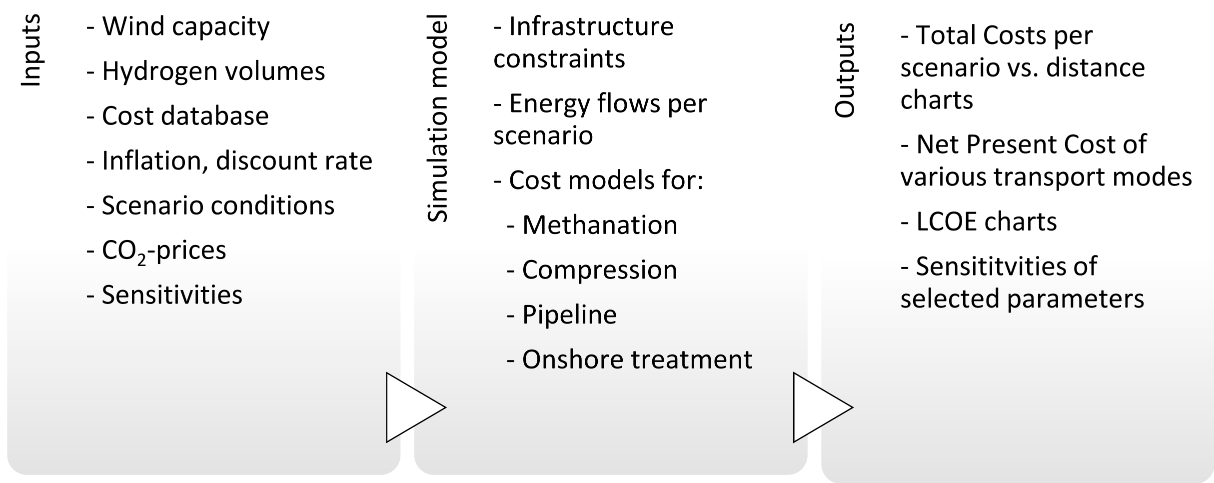

Figure 2 - Description of the information flow in the excel model

2.1.1. Hydrogen volume

The volume of hydrogen to be transported via the offshore infrastructure is determined by the offshore capacity of hydrogen production, which in turn is determined by: the development of a hydrogen economy, the offshore wind capacities, and the limits of available infrastructure.
Since this study is limited to the transportation of hydrogen rather than its production or demand side, the details of the latter aspects are not further described. For additional information on offshore hydrogen production we refer to the study results of e.g. the North Sea Energy consortium, that include the production potential of hydrogen production from electrolysis and steam methane reforming (SMR) incl. CCS [15]. The main argument here is that the complete production process of green hydrogen becomes more energy efficient the closer the conversion takes place to the primary energy source, highlighting the potential economic benefit of hydrogen production offshore. In addition, offshore conversion and transport of hydrogen is presented as a viable alternative to transport electricity to shore, which could also alleviate grid congestion challenges by feeding large quantities of wind electricity into the onshore power grid.

Hydrogen demand

An assumption was made in order to estimate the volumes of hydrogen to be transported in the various scenarios. The TKI Hydrogen Roadmap [3], estimates a potential theoretical demand for hydrogen for all applications in the year 2050 in the Netherlands, summing up to about 14 Mton of hydrogen per year. This (relatively high) theoretical potential suggests for instance a high offtake of hydrogen in the mobility sector of 1 Mton a year (Figure 3).

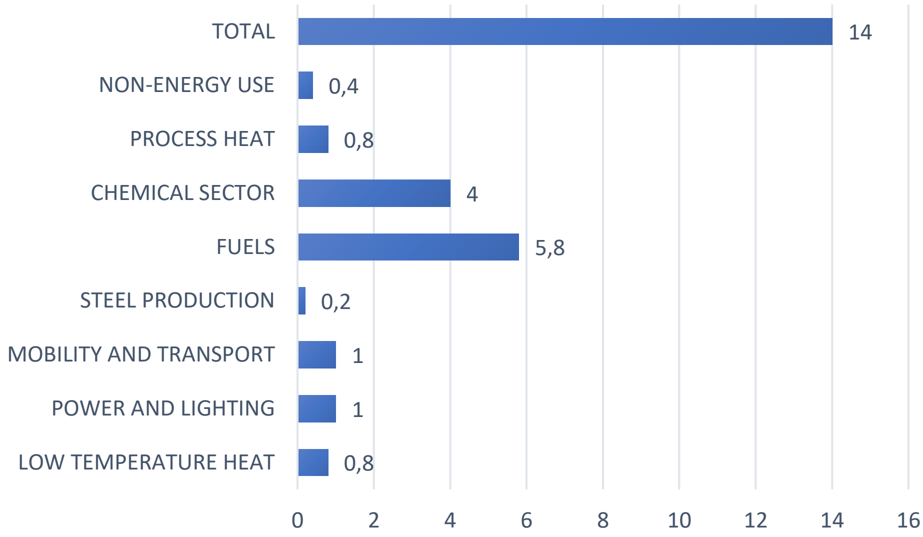

Figure 3 - Theoretical hydrogen demand in Mton H2/year [3]

2.1.2. Hydrogen supply potential

The hydrogen volumes are, next to the transportation distance, one of the major determining parameters in the model. The assumptions of hydrogen supply are based on electrolysis connected to offshore wind power generation. The base of the defined hydrogen volumes is stated in the report *"The future of the North Sea. The North Sea in 2030 and 2050: a scenario study"* [4] that describes a series of scenarios assessing the potential installed wind capacity of the North Sea and more specifically on the Dutch Continental Shelf by 2030 and 2050.

Given that the energy content of hydrogen is 120 MJ/kg or 33.3 kWh/kg (LHV) at 4380 full load hours p.a. (capacity factor of 50%) for offshore wind power generation and a 75% electrolyser efficiency[4], it becomes clear that even in the most optimistic scenario the North Sea wind power generation will be able to contribute only 5.8 Mt of hydrogen per annum which is limited if compared to the projected future demand of 14 Mt p.a. (estimated by the TKI Hydrogen Roadmap for 2050). This optimistic scenario considers max. 60 GW wind power capacity by 2050, according to the estimations of scenario

[4] Siemens SILYZER 300.

"Sustainable Together" [4], and a full allocation of the generated electric energy to feeding electrolysis. By comparison, a wind power scenario according to the "Rapid Development" scenario [4], and an allocation of 20% of the generated electricity results in just 0.6 Mt annual hydrogen production.
However, the four scenarios of future installed offshore wind power described in that particular report are implemented in the model giving the user a choice to select how much of that windpower should be allocated towards the conversion into hydrogen .
The hydrogen scenarios depicted in Table 2 are thus input to the consecutive energy flow calculations of the model. These parameters may change if new scenarios on offshore wind capacity installation may become available or when technological improvement causes load hours or electrolysis efficiency to increase.

Table 2 - Summary of energy transition data, per scenario, for 2030 and 2050 based on [4] and completed with hydrogen conversion potential

Year	Scenario I: Slow Change	Scenario II: Pragmatic Sustainability	Scenario III: Rapid Development	Scenario IV: Sustainable Together
		Greenhouse gas reduction (in %, compared with 1990)		
2030	30	45	40	50
2050	45	80	65	100
		Offshore wind power (GW)		
2030	4.5	7.5	11.5	15
2050	12	22	32	60
		Hydrogen conversion (Mton)		
2030	0.4	0.7	1.1	1.5
2050	1.2	2.1	3.1	5.8
		CCS (Mt CO_2 /year)		
2030	-	-	15	20
2050	-	30	25	45

2.1.3. Reuse of natural gas pipeline infrastructure

Existing pipelines may be suitable for hydrogen transport in case:

a) pipelines are no longer used for natural gas;

b) hydrogen could be admixed to the continuous natural gas stream and;

c) hydrogen could be upgraded to similar gas quality compared to natural gas.

A disadvantage of using the existing pipeline infrastructure is that the infrastructure may not be completely available when needed for hydrogen transportation, e.g. if the transportation of still significant volumes of offshore extracted natural gas has priority. In this case admixture of hydrogen may be the most beneficial, even if certain limitations are set on hydrogen injection due to the capacity limitation of gas treatment plants. These plants, which are the delivery locations of hydrogen in every scenario, are assumed to have a maximum capacity of 35 to 45 MNm^3/day [27].[5] Hence, this is the maximum admissible flow rate for each of the scenarios, and together with the assessment of the trunk lines it determines the maximum volume of hydrogen to be admixed.

Although difficult to predict, the estimated throughput (based on input of EBN) of the existing trunk lines for the coming decades is defined as follows: 15 MNm^3/day in the year 2020 with a linear decline to 2 MNm^3/day in 2040 and subsequently a linear decline to 0 MNm^3/day [6] in 2050.[7] Figure 4 gives a graphical overview of the expected throughput for the existing offshore treatment plants. In addition to the natural gas throughput, it also highlights the potential volumes for hydrogen given the aforementioned parameters of the scenario "Rapid Development" (Table 2).

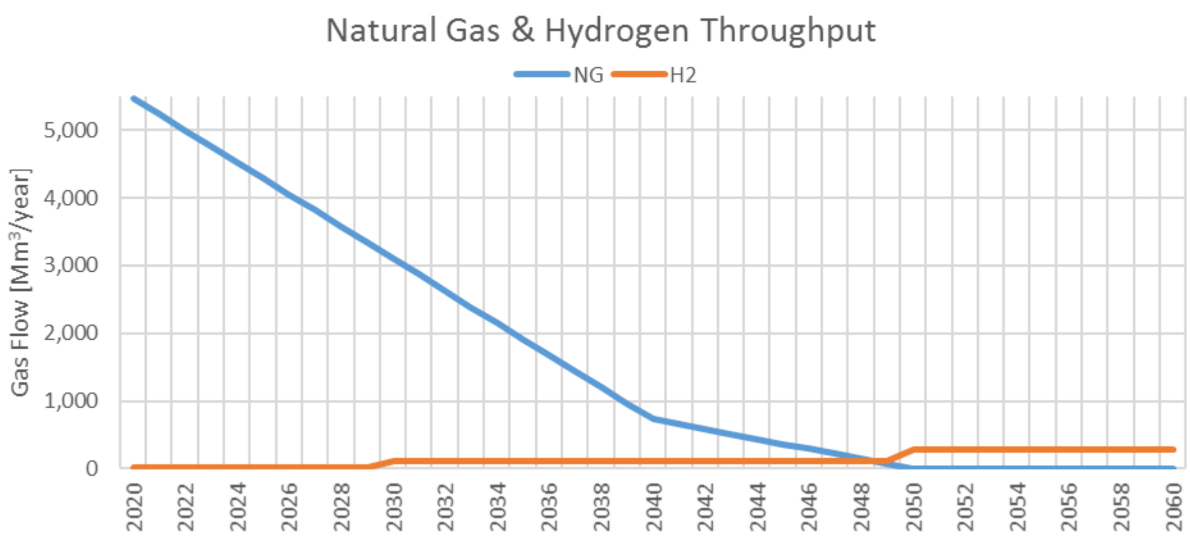

Figure 4 - Natural Gas and Hydrogen volumes per year (natural gas volumes are based on estimations provided by EBN)

[5] Mm^3 = Million normal cubic metres

[6] Estimations are provided by EBN.

2.2. Scenarios

This study comprises five different scenarios that have been established with EBN. One of the objectives of this study is to evaluate tipping-points at which the reuse of existing infrastructure, such as pipelines and compressors, would be less costly than building a dedicated offshore hydrogen transport infrastructure. Table 3 gives an overview of the key differences of the various scenarios in order to be able to assign and combine different parameters and in that way to obtain differentiated transportation methods.

Table 3 - Summary of scenarios

	Pipelines	Stream	Diameter	Design pressure pipeline	Receiving Pressure at consumer	Separation
Scenario 1	Existing	100% H_2	36 inch	110 bar	70 bar	N/A
Scenario 2	New	100% H_2	24 inch	35 bar	70 bar	N/A
Scenario 3	New	100% H_2	36 inch	110 bar	70 bar	N/A
Scenario 4a	Existing	15 vol% Admix	36 inch	110 bar	70 bar	No
Scenario 4b	Existing	15 vol% Admix	36 inch	110 bar	70 bar	Yes
Scenario 5	Existing	100% CH_4	36 inch	110 bar	70 bar	No

2.2.1. Scenario 1

This scenario will be characterised by its use of existing infrastructure with a design pressure of max. 110 barg and a 100% H_2 stream. The design pressure, which is common standard in the existing offshore gas network, is taken as a basis in the analysis. Pipelines retrofitting would be necessary to prevent leaking and embrittlement due to the H_2 stream. Moreover, it is expected that a pure H_2 stream requires dedicated compression equipment. The CAPEX and OPEX associated with dedicated hydrogen compression systems as well as the costs for retrofitting and OPEX of the existing infrastructure (pipelines and compression) constitute to the main cost parameters. The main advantage of this scenario is that the costs for hydrogen infrastructure can be significantly reduced by reusing existing pipelines.

2.2.2. Scenario 2

A main disadvantage of using the existing pipeline infrastructure is that the infrastructure might not be completely available on time due to the fact that part of the gas extraction facilities do still need to transport natural gas to shore. Another risk is the technical feasibility to transport pure hydrogen flows in case the existing pipelines are not suitable for hydrogen transport (e.g. due to leakages and steel embrittlement). Scenarios 2-5 provide various alternatives. Scenario 2 will be characterised by its use of new infrastructure with a design pressure of 35 barg and a 100% dedicated H_2 stream. Although investment in dedicated pipelines is required, no new investments in compression systems is required. Current PEM-electrolyser systems, such as the Sylizer from Siemens, produce hydrogen at an output pressure of 35 barg. It is expected that due to technological innovation this might in the future increase towards 60 barg [17]. Nevertheless one might need onshore compression to bring it further land-inward at a pressure of to 70 barg. Hence the CAPEX and OPEX of a new onshore electric hydrogen compressor and new offshore pipeline infrastructure have been considered as the main cost parameters.

2.2.3. Scenario 3

Scenario 3 focusses on a 100% dedicated H_2 stream pipeline with design pressure of 110 barg. Next to the CAPEX and OPEX of new infrastructure (pipelines and compressors) this scenario accounts for an offshore electric-driven hydrogen compressor to accommodate demand for 70barg output pressure.

2.2.4. Scenario 4

This scenario is characterised by its use of existing infrastructure with a design pressure of 110 barg and an admixed stream of natural gas and hydrogen. This scenario is especially relevant to investigate, since natural gas production is expected to continue to a certain extent in future whereas the increased wind capacity is increasing steadily. The exact composition of the mixture may, however, change over the years as the volumes of gas decrease. However, a maximum of 15 vol% of hydrogen in the natural gas mix is assumed[8].

There are two sub-scenarios associated within scenario 4, where sub-scenario 4a considers the delivery of the admixed blend to shore, and sub-scenario 4b considers a separation step onshore to isolate the hydrogen from the blended stream before its final delivery.

[8] Limitation confirmed by EBN due to the receiving equipment at the gas plant on shore.

The cost parameters consist, apart from retrofitting cost, of the existing pipelines, the CAPEX and OPEX of new electric hydrogen compressors, and the OPEX of the existing pipeline infrastructure. In sub-scenario 4b CAPEX and OPEX costs of the separation step are added.

2.2.5. Scenario 5

This scenario contains a second conversion process in which the hydrogen molecules are combined with CO_2 molecules to methane. The produced methane is then transported via the existing transport infrastructure (incl. existing compression system) with a design pressure of 110 bar. The scenario consists of various sub-scenarios with the varying elements of methanation technology and CO_2 sources (see section 3.1.3). The main cost components in this scenario are the CAPEX and OPEX of the methanation step (incl. CO_2 purchase) and the OPEX of the existing infrastructure (pipelines and compressors).

3. Technical considerations

In the following section a brief description of the different technical considerations that were used in the assessment of the different scenarios is made. The objective of the sections is not to describe in detail the technologies themselves but to point out which where the selected ones and the reasons behind them.

3.1. General comparison of hydrogen and methane infrastructure

The feasibility of using existing natural gas pipelines for hydrogen is still in discussion since the difference in the characteristics of methane and hydrogen molecules (see also

Table 4) may lead (depending on material and equipment choices) to: diffusion losses, brittleness of materials and seals, incompatibility of compressor lubrication with hydrogen, etc. This is also partly due to the fact that hydrogen molecules are about 6 times smaller than methane molecules, requiring a careful assessment whether existing pipelines are prone to leakages. In addition, the volumetric lower heating value of hydrogen[9] compared to natural gas is about 30-40% smaller suggesting that hydrogen pipelines can transport 30%–40% less energy than natural-gas pipelines of the same diameter. As a consequence, hydrogen pipelines need to operate either at higher pressures or have to be of larger diameter to supply the same amount of energy. For compression hydrogen needs dedicated compressors which require much more energy than natural gas compressors, again, due to the smaller molecule size. Hence, compressor design and material need to be adapted to accommodate a higher flow in order to lower the transportation costs and ensure the reliability of the transport service [7]. The compression rate needed to accommodate the pipeline design pressure strongly depends on the outlet pressure of the electrolyser.

[9] The heating value of hydrogen in the pipeline is about one-third of that of natural gas until at a pressure of 100 bar. Long-distance pipelines typically are designed for a pressure of 30 to 100 bar.

Table 4: Comparison of hydrogen and methane characteristics

Specification	Methane	Hydrogen
Density at 20ºC and 100kPa (kg/m³)	0.668	0.0899
Diffusion coefficient in air (cm²/s)	0.21	0.756
Energy content (LHV, MJ/kg)	42-55	120
Flammability range	5.3-17	4-75
Wobbe index in (MJ/M³) (measured at 15ºC)	50.73	45.88

The injection of hydrogen in the natural gas grid is limited as hydrogen influences the characteristics of the gas mixture significantly, e.g. impacting its burning velocity and Wobbe-Index (WI). Annex I – Technical Discussions provides more insight in these effects. Based on these hydrogen characteristics, natural gas can only be admixed up to a certain limit to prevent severe effects on material integrity (especially at valves and compressor units).

Currently, the feasibility of using existing pipelines for hydrogen lays on the material of the gas pipes (specifically the carbon content of steel) and therefore potential re-use must be studied on a case-by-case basis. Hydrogen requires a non-porous material as it can diffuse quickly through most materials, welds, and seals causing severe degradation of steels, mainly by hydrogen embrittlement [11]. As an alternative to the reuse of existing pipe-infrastructure a dedicated hydrogen pipeline could be established that secures the potential for pure hydrogen offtake and provides more flexibility regarding the shore connection. The next sections discuss the mentioned concepts of reuse.

3.1.1. Using the existing O&G network

Gaseous hydrogen transported via existing pipelines is a low-cost opportunity for delivering hydrogen. The high initial capital costs of constructing new pipelines may constitute a significant barrier to installing or expanding hydrogen pipeline delivery infrastructure. Research today, therefore, focuses on overcoming technical matters related to pipeline transmission, including but not limited to:

- the potential for hydrogen to embrittle the pipeline material, heat affected zones and welds used to fabricate the pipelines;
- the need to control hydrogen permeation and leaks (an estimate by GTI suggests that leakage rates would double with 20% hydrogen, but would still be economically insignificant at just 0.0002% of the total flow rate);
- the need for lower-cost, more reliable, and more durable hydrogen compression technology [8].

Adapting part of the current natural gas infrastructure in order to accommodate hydrogen is seen as a possibility for rapidly expanding the hydrogen delivery infrastructure. In addition, retrofitting natural gas pipelines to carry a blend of natural gas and hydrogen (up to around 15 vol% of hydrogen) may require only modest adjustments to the pipeline. Retrofitting existing natural gas pipelines to deliver pure hydrogen may require more generous modifications. Current research and studies are examining both approaches [6]. An overview of technical barriers and top priority R&D needs is given in the table below, based on [7] [11], and in line with the *Strategic Research Agenda within the European Hydrogen and Fuel Cell Technology Platform*.

Table 5 - Technical barriers/improvements areas and significant R&D need for Hydrogen pipeline transportation, based on. [7], [10]

Technical barrier/improvement areas	Related R&D need
Hydrogen-induced degradation of steels	Cheaper hydrogen insensitive materials for high pressures.
	Internal coatings and linings and spraying pigs.
	New/advanced polymers impermeable to hydrogen.
Pipeline technology	Innovative welding and joining methods, risk assessment.
	Potential innovations in this field include using fibre reinforced polymer (FRP) pipelines for hydrogen transportation. Their installation costs are about 20% less than that of steel pipelines because the FRP can be obtained in sections that are much longer than steel.
	Inexpensive, hydrogen-fitted valves, metering systems, components for high- and medium-pressure transmission and low-pressure distribution.
Compressor technology (Reciprocating)	Simpler design (minimisation of seals and valves), improvement of volumetric efficiency, reduction of exposure to hydrogen contamination by lubricants, less expensive materials.
Compressor technology (centrifugal)	Development of centrifugal compressors with a dedicated design for H_2.
Leak detection	Smart sensors, odorants, intelligent pigs.
Hydrogen-natural gas separation	Development of separation membranes.
Elecrolyser technologies	Further development of High-Pressure Electrolysis (HPE), which is based in the PEM electrolysis, but with the difference that the compressed hydrogen output is around 120 to 200 bar at 70 ^{o}C.

3.1.2. Admixing hydrogen in the existing pipeline network

The use of a mixed stream of natural gas and hydrogen has the potential of greening the existing consumption of gas without needing to invest in adjustments to the transportation network or stationary applications, such as gas turbines. Therefore, the question that rises is how much hydrogen can be mixed and injected into the natural gas stream infrastructure.

DNV GL together with Gasunie Transport Service (GTS) have investigated to what extent the existing gas infrastructure could be used, considering the security and stability of the network. They concluded that GTS's existing high-pressure gas network offers excellent opportunities for transporting either a 100% hydrogen stream or a natural gas-hydrogen blend [7].
According to the DNV GL study, there are two main limitations when trying to mix hydrogen with natural gas. The first one is due to legal requirements, that determine a maximum 2 vol% restriction of hydrogen into the Netherland's high-pressure natural gas transport system. The capabilities of existing end-user equipment form a second limitation leading to recommendations to keep hydrogen concentrations below 2vol% of the total gas stream. For new sophisticated equipment this fraction could be up to 15 vol%. Whereas the latter limitation is inspired by equipment use at the end point of the gas value chain, the limit might not be relevant to the purpose of pure transportation activities [7].
Considering the technical feasibility of blending the hydrogen with the natural gas stream at the injection point, measures may need to be taken at the extraction point to separate both gases, but 'filtering' the hydrogen from the natural gas is costly and requires additional energy. Another aspect that could pose problems is the highly variable gas quality, which is the combined effect of i.e. the filtering and variations in the flow rate throughout the entire year.

H_2 separation and quality

The most suitable technology in terms of H_2 separation for the given amounts of hydrogen production is currently Pressure Swing Absorption (PSA)[10]. However, for the volumes flows that current measuring stations typically process (200,000 to 300,000 Nm^3/h), the size of a PSA plant would be too extensive. However, given that the reception locations in this study are large gas plants onshore with sufficient and available square meters to fit these plants, PSA is yet assumed to be an adequate solution.[11]
Pressure swing adsorption (PSA) and vacuum pressure swing adsorption (VPSA) are the most common purification systems for a methane stream or a reformate with a high content of H_2. A brief description of the process is given in the study "Green Hydrogen Production from Raw Biogas: A Techno-Economic Investigation of Conventional Processes Using Pressure Swing Adsorption Unit" [12] :

"These units use multiple beds filled with adsorbent material, which undergo a sequence of steps, cyclically repeated. The step sequence is generally made of (a) an adsorption step at high pressure, in which impurities are adsorbed and removed from the feed stream, while hydrogen is collected in the

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[10] Link: Hydrogen Recovery by Pressure Swing Adsorption (The Linde Group)
[11] As explained and confirmed by EBN B.V.

product stream, (b) a depressurization/pressurization step, in which two columns at different pressure communicate, one decreasing pressure while the other one increases up to a common value, (c) a purge step at low pressure, in which impurities are desorbed from the bed by also using part of the hydrogen produced. Design of a PSA or VPSA unit is not a trivial task, due to the large number of parameters in play, including the detailed design of subcomponents and auxiliaries."

3.1.3. Methanation

Methane has some chemical advantages over hydrogen (see Table 4), and also advantages on a transportation point of view since it can be directly injected into the existing natural gas grid without the need of any retrofitting or adjustments to the latter. Hence, a scenario with a methanation step is analysed.

For converting hydrogen into methane, a methanation reactor and CO_2 source are required. There are currently two mainstream methanation technologies available: biological methanation and catalytic thermochemical methanation. Regarding CO_2.sources one could differentiate between sources from fossil fuels, air, or biogenic. Within the methanation process CO_2 is supposed to react with H_2 on a basis of 5.5:1. So, if one has about 65,000 ton of H_2 , one need at least 350 ton of CO_2. Annex I – Technical Discussions presents more detailed information on each of these technologies.

This study assumes a thermochemical methanation relying on the advantage that the obtained hydrogen from the electrolyser has high purity levels, an stringent requirement if nickel is to be used as a catalyst for its high activity and methane selectivity while having a low material cost. Moreover, the chemical methanation process can be operated dynamically, which is a prerequisite when dealing with a hydrogen source powered by wind.

3.2. New dedicated pipeline costs

Gaseous hydrogen can be transported through pipelines in a very similar way compared to natural gas. Existing dedicated hydrogen pipelines are usually owned by merchant hydrogen producers, and these pipelines are usually strategically located where large hydrogen users are concentrated, such as petroleum refineries, chemical plants and steel production facilities.

The assessment of the energy required to deliver hydrogen through pipelines is derived from natural gas pipeline operating experience. Also, hydrogen pipelines may have to be larger in diameter to reduce the energy requirement for transporting it.

In the DNV GL "Verkenning Waterstofinfrastructuur" report [7] an assessment of the transport capacity of the existing gas pipelines is done by making the following comparison. The energy content (HHV) of

hydrogen is about 13 MJ/Nm³, whereas the HHV of high-caloric gas (H-gas) is equal to approximately 40 MJ/Nm³ (or about 35 MJ/Nm³ for Groningen gas). One can therefore conclude that there is three times of hydrogen volume required to yield the same energy content of a given natural gas volume transported.
Another option is to increase the velocity of hydrogen flow to three times higher than for natural gas. However, such high speeds can lead to vibration and erosion problems but considering that the density of hydrogen is 1/9 of that of natural gas, the impact of higher flow rates is considered to be sufficiently compensated. Although a detailed analysis should be conducted, it is a priori expected that transition from natural gas to hydrogen has little or no effect on the occurrence of vibration problems. [7]

The energy needed to pressurize hydrogen for pipeline transmission will be significant in terms of capital investments and electricity demand. To illustrate this, in "The Future of Hydrogen: Bright or Bleak?" report [8] it is calculated that moving a specific energy flow of hydrogen through a given pipeline requires about 3.85 times more energy than for natural gas. Hence, this area may benefit from the further development of new technologies. Those used today are mature and have not been improved significantly for many years. However, for transmission this is not a priority research area, unless it is related to distributed hydrogen production systems, as mentioned above.

Potential innovations in this field include using fibre reinforced polymer (FRP) pipelines for hydrogen transportation. Their installation costs are about 20% less than that of steel pipelines because the FRP can be obtained in sections that are much longer than steel[12,13], which significantly minimizes welding requirements [10].

3.3. Compression

High pressure hydrogen compression is a prerequisite for its transport. Whether a blended stream of natural gas and hydrogen is transported, or a 100% hydrogen stream, current compression technologies for natural gas will commonly not be adequate, so that new compression facilities will be required for all scenarios, except for scenario 5. In case of methanation it is assumed that the syngas is composed in such way that the existing compressor is capable to compress the syngas without any operational drawbacks.

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[12] See the Natural Gas Pipeline Technology Overview from Argonne National Laboratory.
[13] FRP can be delivered in lengths of up to 0.5 mile.

Because of its lower molecular weight and viscosity, hydrogen flows move 2–2.5 times faster than natural gas in a pipeline under the same conditions of pipe diameter and pressure drop. However, because of the lower heating value of hydrogen,[14] such a hydrogen pipeline carries about 30%–40% less energy than a natural-gas pipeline. That is why hydrogen pipelines need to operate at higher pressures to supply the same amount of energy, or need to have a larger diameter [1].

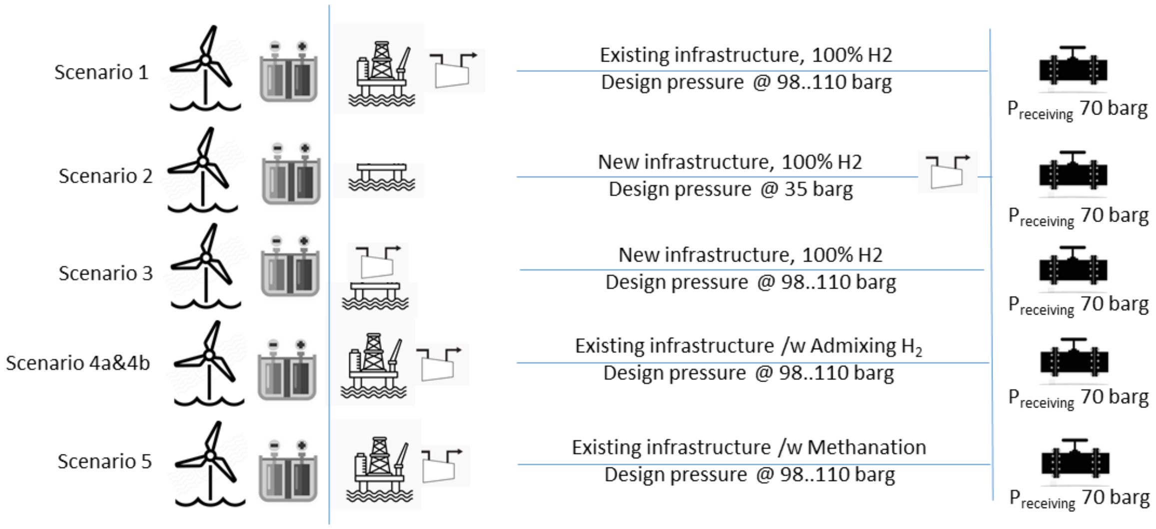

Figure 5 - Compression in each scenario

Assuming that at the upstream end in each scenario (the production location) a PEM electrolyser will split the water molecules using offshore wind-power to produce the hydrogen, output pressure at the pipe inlet will be in the order of 35 barg. In each scenario the hydrogen is compressed to satisfy the required downstream receiving pressures of 70 barg. For simplicity purposes, a simple phase stream has been considered in every scenario leaving the multi-phase analysis to be done in a future study where specific locations would be considered.

The compressed output is around 15-25 bar for alkaline technology and approximately 35 bar for PEM.[15] It is expected that due to technological innovation this may increase towards 60 barg [17]. Regardless of which of these two technologies are being used, their outlet pressures demand a compressor station to boost the hydrogen pressure in order to be able to transport it.

New developments are being carried out to advance on the High-Pressure Electrolysis (HPE), which is based in the PEM electrolysis, but with the difference that the compressed hydrogen output is around 120 to 200 bar at 70 ^{0}C. This technology could represent huge advantages since the high cost of

[14] The heating value of hydrogen in the pipeline is about one-third that of natural gas until at a pressure of 100 bar. Long-distance pipelines typically are designed for a pressure of 30 to 100 bar.
[15] Examples of different electrolysis technologies and their outlet pressure: Alkaline→ Hydrogenics HySTAT™ 15-25 barg, Etogas 15 bar, Tractebel 0-15 bar; PEM→ Siemens Silyzer 200/300 35 bar, Tractebel 30-60 bar.

compression is making it difficult for all hydrogen production pathways to match the energy cost of conventional fuels. Further advantages are that it eliminates one or more stages of mechanical compression, thereby reducing maintenance needs as there are no moving parts and no contaminants; it also reduces the overall system complexity which translates into lowering drying requirements. [16] The US DOE indicates that high-pressure electrolysis, supported by ongoing research and development, will contribute to the enabling and acceptance of technologies where hydrogen is the energy carrier between renewable energy resources and clean energy consumers.[16]

Mitsubishi is pursuing such technology in its High-pressure hydrogen energy generator (HHEG) project.[17] The Forschungszentrum Jülich, in Jülich Germany, is currently researching the cost reduction of components used in high-pressure PEM electrolysis in the EKOLYSER project. The primary goal of this research is: to improve performance and gas purity; reduce cost and volume of expensive materials; and reach the alternative energy targets set forth by the German government for 2050 in the Energy Concept published in 2010.

Although HPE technology presents a promising option, further advancement is required to make it commercially viable, mainly in its membrane, stack and balance of plant (BOP) requirements [16].

[16] https://www.hydrogen.energy.gov/pdfs/progress06/ii_h_5_ibrahim.pdf

[17] http://www.mitsubishi.com/mpac/e/monitor/back/0408/news.html

4. Economic parameters

Each scenario contains various costs components that jointly determine the LCoE of hydrogen transport (see also Table 6). The following sub-sections give an overview of the calculation method of the scenario specific cost components (incl. equations used to determine the ultimate cost structure).

	Pipeline requirements	Compression requirements	Other investments
Scenario 1	Retrofitting existing pipeline (CAPEX) Yearly OPEX existing pipeline	Dedicated offshore H_2 compressor (CAPEX&OPEX)	N/A
Scenario 2	New dedicated H_2 pipeline (CAPEX&OPEX)	Dedicated onshore H_2 compressor (CAPEX&OPEX)	N/A
Scenario 3	New dedicated H_2 pipeline (CAPEX&OPEX)	Dedicated offshore H_2 compressor (CAPEX&OPEX)	N/A
Scenario 4a	Retrofitting existing pipeline (CAPEX) Yearly OPEX existing pipeline	Dedicated offshore H_2 compressor (CAPEX&OPEX)	N/A
Scenario 4b	Retrofitting existing pipeline (CAPEX) Yearly OPEX existing pipeline	Dedicated offshore H_2 compressor (CAPEX&OPEX)	Gas separation costs (CAPEX&OPEX
Scenario 5	Yearly OPEX existing pipeline	N/A	Methanation technology and CO_2 sources incl. transport to shore (CAPEX&OPEX)

Table 6: Overview of cost elements per scenario

4.1. Existing pipeline

Typical costs for an offshore trunk line consist of intelligent pig runs, rock dumping and valve inspections. The costs are dominated by the intelligent pig runs, although rock dumping can be a significant cost position as well but this is very dependent on the location of the pipelines [26]. For this study an estimated OPEX for a trunk line of 4,000 to 6,000 EUR/km is used.[18]

4.2. New dedicated hydrogen pipelines

The method to construct associated costs follows the series of estimations made by EBN and Gasunie in their report 'Transport en opslag van CO2 in Nederland' [30]. It states that on average, besides the pipeline material, two major factors are crucial for pipeline investments costs: the diameter and the distance to be covered. Generally put, costs per kilometer decrease as the distance increases. The report estimates were based on market prices and globally realized projects; because market prices were quite low at the measurement moment (2017), the estimates are assumed to have accuracy ranges from -20 to +40%. Other factors that can have a prominent impact on the cost of laying new pipelines include: submarine obstacles (such as other pipes and cables), but also super-sea obstacles, such as platforms or wind farms. All this may require that crossings be implemented. As this study does not focus on a specific location within the North Sea, it is not possible to assess how many and what type of crossings should be considered when concrete locations will be studied. Such costs obviously must be taken into consideration in greater detail

4.3. Hydrogen Separation

An economic analysis by Gioele Marcoberardino et al., 2018 [12], established in the best case a hydrogen production cost of around 5 €/kg when using a vacuum PSA system that allowed to achieve a 99.999% hydrogen purity. However, the drawback is that the recovery rate the system allows is lower with respect to the typical values of a large PSA unit (about 80-90%) that uses 10-12 beds.

A different option could be using a pipe-in-pipe concept where a new pipe slides into the existing pipeline and transports the hydrogen separately. This concept is associated with many modifications to existing stations (valve-locations), so that this concept can be more expensive than constructing an entirely new pipe. Next to the technical issues of separation, a legal-economic point is which party is responsible for gas separation and hence quality conversion of the gas streams.

[18] Estimations are provided by EBN.

Research is being carried out on new separation technologies based on membranes. The FCH JU[19] project HyGrid[20] focuses on the design, scale-up and demonstration at industrially relevant conditions of a novel membrane-based hybrid technology for the direct separation of hydrogen from natural gas grids. The concept is to separate the hydrogen via a combination of membranes, electrochemical separation and temperature swing adsorption, in an effort to decrease total cost of hydrogen recovery. The project targets a pure hydrogen separation system with a power requirement of < 5 kWh/kgH_2 and costs of < 1.5 €/kgH_2. To achieve this, HyGrid aims at developing a novel hybrid system integrating three technologies for hydrogen purification combined in a way that enhances the strengths of each of them: membrane separation technology is employed for removing H_2 from the 'low H_2 content' (e.g. 2-10 %), followed by electrochemical hydrogen separation (EHP) optimal for the 'very low H_2 content' (e.g. <2 %), and finally by temperature swing adsorption (TSA) technology to purify from humidity produced in both systems upstream.

4.4. Methanation

The University of Linz has made cost predictions on methanation systems as part of their activities in the Store&Go project. [22] The table below, retrieved from their latest report, shows similar cost reduction trends for catalytic and biological methanation systems. The biological methanation cost curve is, however, somewhat steeper because learning effects on catalysts are expected to be relatively small, and the percentage increase in cumulative production via biological methanation is expected to be relatively high. Apart from learning effects, significant economies of scale will reduce methanation costs.

Figure 6Figure 6, highlights the effect of economics of scale on the specific cost of biological and chemical methanation and the presented costs are also taken as a basis for this study. However, so far no methanation plants are operated on a commercial basis.

[19] The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) is a unique public-private partnership supporting research, technological development and demonstration (RTD) activities in fuel cell and hydrogen energy technologies in Europe. The three members of the FCH JU are the European Commission, fuel cell and hydrogen industries represented by Hydrogen Europe, and the research community represented by Hydrogen Europe Research.

[20] http://www.fch.europa.eu/project/flexible-hybrid-separation-system-h2-recovery-ng-grids

Methanation system	Calculated costs [€$_{2017}$/kW$_{SNG}$]			
	initial (2017)	2020	2030	2050
Catalytic	600	579 – 579	437 – 444	270 – 295
Biological	600	551 – 552	357 – 363	213 – 232

Table 7 - Summary of calculated cost reduction potential for 5 MW SNG-output methanation systems; copied from [28]

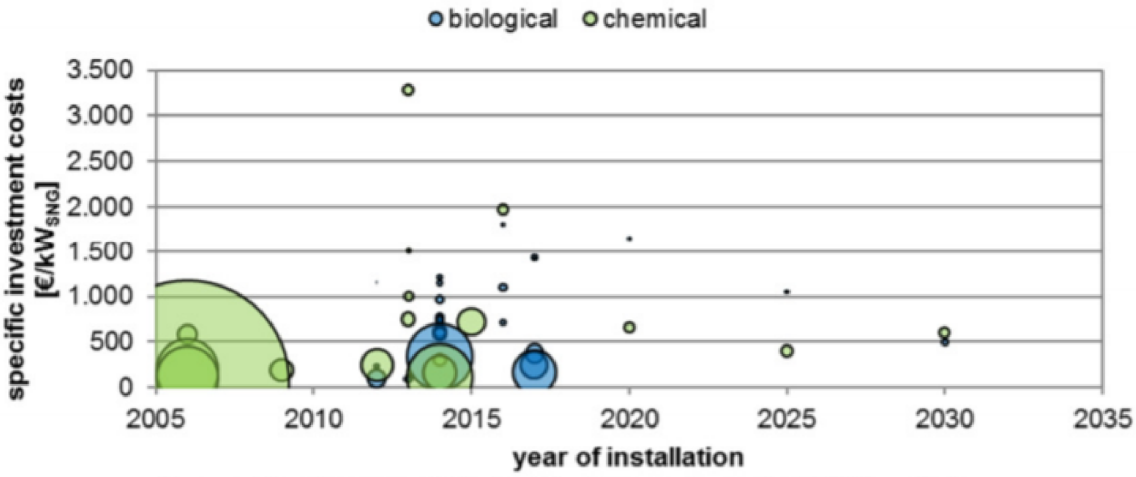

Figure 6 - Overview of the specific investment costs for chemical and biological methanation plants related to the year of installation and the nominal power of the plant(retrieved from [28])

In order to deliver syngas that is claimed to be green, one has to take into account the carbon footprint of the supply chain, e.g. the used CO_2 feedstock. With respect to electricity supply used to generate hydrogen, this is typically guaranteed through the supply of green electricity. In addition the sustainability of the used CO_2 will have to be demonstrated (for some results, see Figure 7)

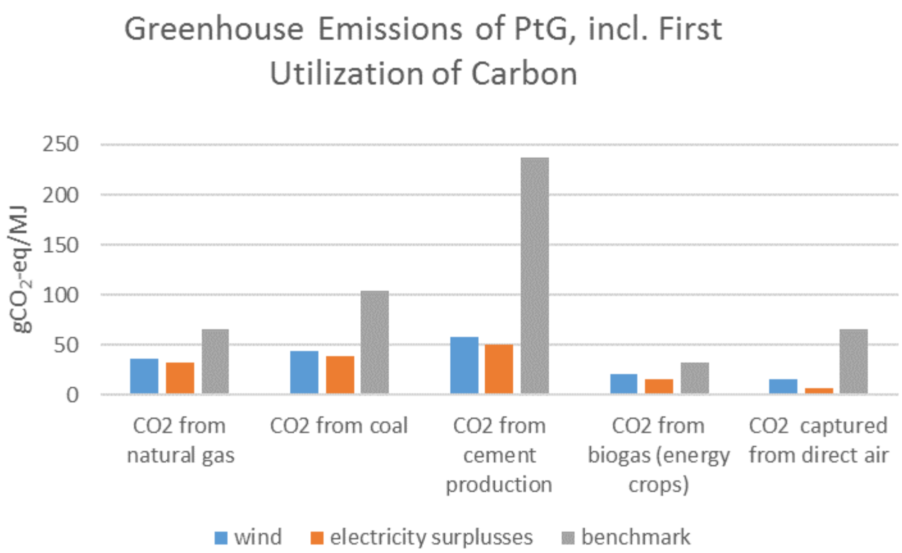

Figure 7 - Greenhouse gas emissions of PtG from diverse electricity resources and CO2 sources. Graphic compilation based on data retrieved from [20]

Social acceptance or legal issues may arise if rather 'grey' CO_2 sources would be used to merge with the green hydrogen molecules. It is therefore important to be able to rank CO2 sources, that can be grouped in three main categories: fossil sources, biogenic sources and ambient air. Annex I – Technical Discussions provides an overview of the characteristics of the various CO_2 sources, incl. capture cost characteristics will be discussed. Note already, however, that the methanation process in our study takes place in an offshore environment, so that it may be complex to assure continuous flows of pure and 'green' CO_2.

4.5. Compression costs

For each of the scenarios compression costs are included. For this purpose, a compression power, noted P in kW, is calculated determining together with the operating hours and the load profile the energy required for compression. The equation below is based on two reports, *Techno-economic assessment of hydrogen transmission & distribution systems in Europe* [11] and Jean Andre et al., 2014 [13].

Equation 1 - Compression Power

$$P = \frac{Q}{3600 \times 24 \times 33{,}33} \times \frac{Z \times T \times R}{M_{H_2} \times \eta_{comp}} \times \frac{N_\gamma}{\gamma - 1} \times \left[\left(\frac{P_{out}}{P_{in}} \right)^{\frac{\gamma-1}{N_\gamma}} - 1 \right]$$

where:

- Q the flow rate (in kWh per day) by taking a low heating value (LHV) of 33.33 kWh/kg specific to hydrogen,
- P_{in} the inlet pressure of the compressor (suction),
- P_{out} the outlet pressure of the compressor (discharge),
- Z the hydrogen compressibility factor,
- N the number of compressor stages,
- T the inlet temperature of the compressor (278 K),
- γ the diatomic constant factor (1.4),
- M_{H2} the molecular mass of hydrogen (2.0158 g/mol)[21],
- η_{comp} the compressor efficiency ratio (here taken as 75%),
- the universal constant of ideal gas R = 8.314 J K-1 mol-1.

The pressure drop occurring in the pipe due to friction when transporting hydrogen (or any other gas) depends on: the pipe diameter, the gas throughput, the surface properties of the pipe material, the

[21] Interview with Gasunie on 07/11/'17.

pressure level in the pipe, and the density of the gas. Generally, the pressure drop needs to be compensated by recompression (booster stations) per every 200–300 km on onshore installations, but in offshore scenarios, such as the ones studied in this report, the pressure drop is added to the receiving pressure requirement. The pressure drop in high-pressure gas pipelines can be calculated according to the Darcy–Weisbach equation as follows:

Equation 2 - Darcy-Weisbach Pressure Drop equation

$$P_{in}^{\ 2} - P_{out}^{\ 2} = f \cdot \frac{16}{\pi^2} \cdot \rho \cdot P_0 \cdot \frac{T}{T_0} \cdot L \cdot Z \cdot q^2 \cdot \frac{1}{d^5}$$

where:

P_{in}, P_{out} Inlet and outlet pressure of pipeline (Pa),

f Pipe friction factor (Moody factor),

P Gas density under normal conditions (kg/m^3),

P_0 Normal pressure (101 300 Pa),

T Gas temperature (K),

T_0 Normal temperature (273.2 K),

L Pipeline length (m),

Z Compressibility factor of the gas,

q Volume flow under normal conditions (Nm^3/s),

d Pipeline diameter (m).

Following the same report insights and in line with 'The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs' [14], the compression CAPEX relates in a linear way to the compression power (Equation 3), while for its operational expenditures an annual maintenance fee of 3% of the CAPEX is assumed along with the electricity costs to run the compression station (Equation 4).

Equation 3 - Compression CAPEX

$$CAPEX_{compression}[€] = 2545 \times P$$

Equation 4 - Compression OPEX

$$OPEX_{compression}\left[\frac{€}{a}\right] = \left(A_0 \times H_{year} \times e/DTE\right) \times P + 0.03 \times CAPEX_{compression}$$

where:

A_0 Availability (85%),

H_{year} Hours per year (8760h),

e the electricity costs (0.06 €/kWh),

DTE the Driver Thermal Efficiency (90%).

5. Outcomes

5.1. Parameters setting

The parameters described in the following sections were set to the indicated values in order to achieve a coherent and comparable result between every scenario. Two main set of parameters were chosen to show a ‘Simplistic’ approach and a ‘Complex‘ one. In the former, the aim was to show a clear distinction between the main variables of every scenario, and therefore there is no time consideration which reflects in a constant supply of hydrogen (given by a defined wind power capacity), and results are timeless. In the latter, the model exploits the full complexity of the system, following the potential wind power capacity of a ‘Rapid Development’ scenario [9] and correspondingly an increasing production of hydrogen throughout the lifetime of the project.

5.1.1. Simplistic Approach

This approach is meant to provide a clear distinction between the different scenarios by simplifying mainly the wind power generation and consequently the hydrogen production. It is also worth mentioning that this approach does not consider a time frame.

Wind Power Capacity & Hydrogen Production

Wind Power capacity is set at 3 GW[22] with a capacity allocation of 20% towards PEM electrolyzers working at 75% efficiency. This configuration leads to an electrolyzer power of 0.51 GW and a hydrogen energy of 2,193 GWh considering 4,300 full load hours.

Hydrogen Injection

Given the aforementioned conditions that give form to this Simplistic approach, a potential hydrogen injection flow into the natural gas stream was obtained and showed to be equal to the full amount of hydrogen production. Even though the maximum allowable per cent of admixing was set to a 15 (vol%), due to the wind power capacity selected and the electrolyzers characteristics, the obtained admixing was in the range of 0.5 (vol%).

[22] Value set by EBN to reflect the potential IJmuiden Ver project output.

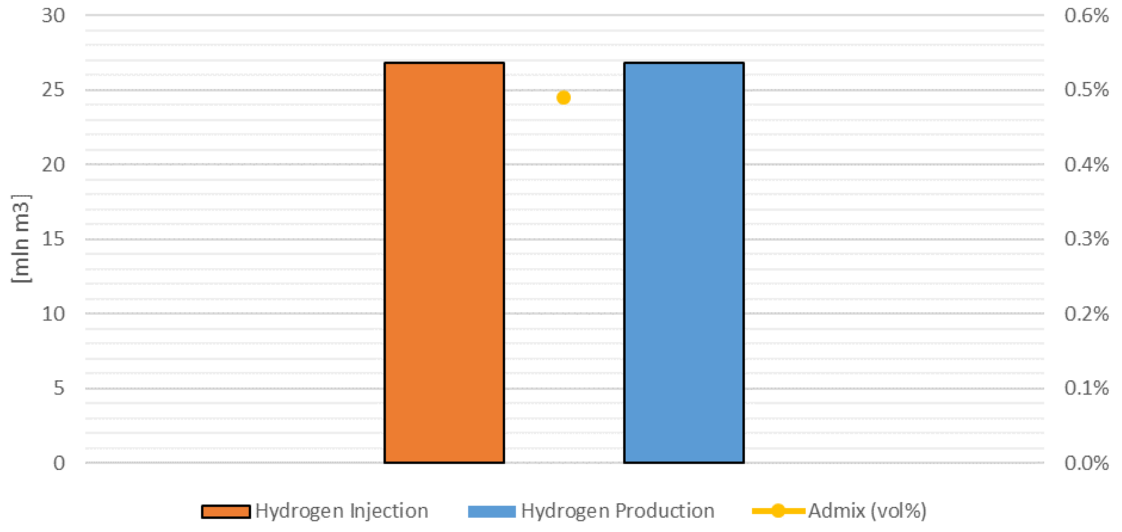

Figure 8 - Hydrogen Production & Injection (Simplistic Approach)

Total Cost per Scenario vs Distance

Figure 9 shows the results in the Simplistic approach, which were plotted in a line graph depicting the total cost per scenario along distances ranging from 50 to 250 km.

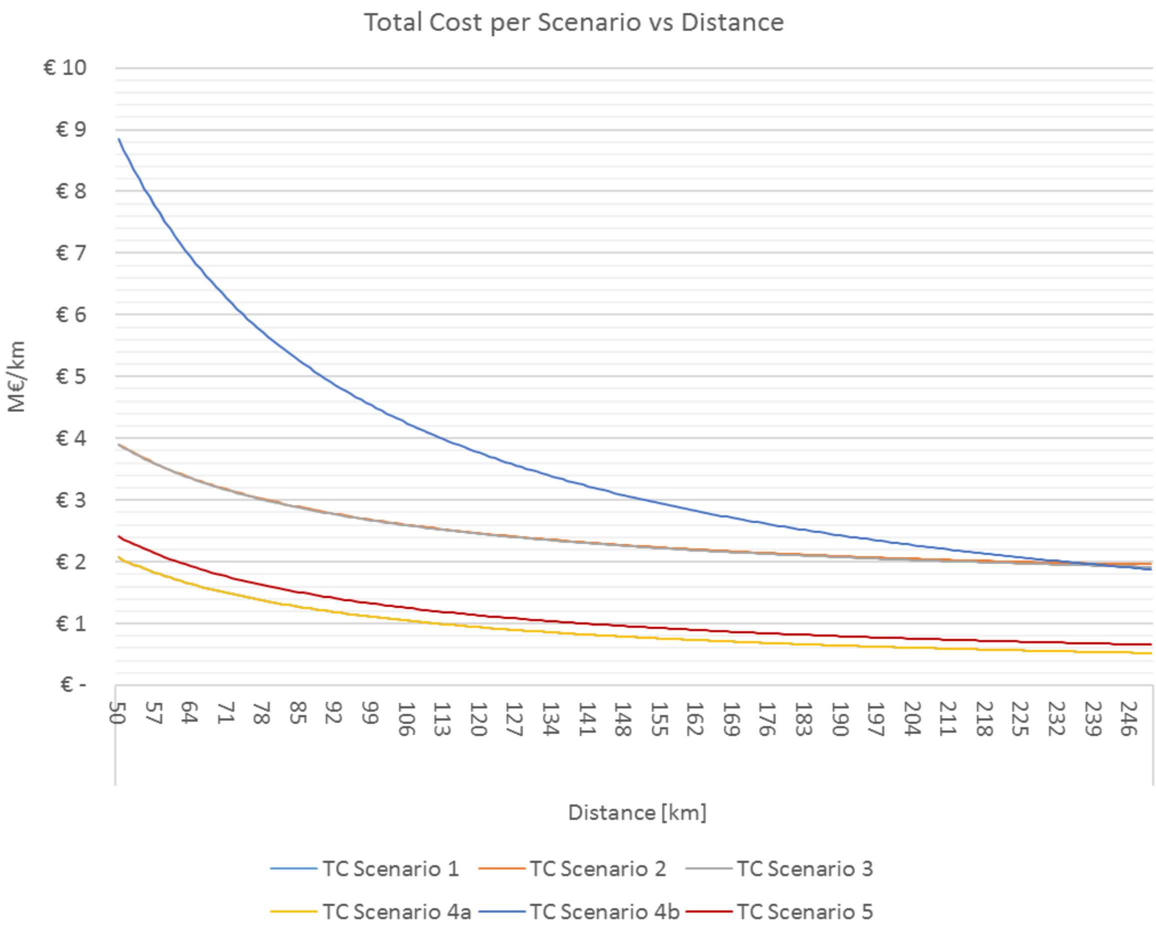

Figure 9 - Total Cost per Scenario vs Distance (Simplistic Approach)

The graph above shows that the most expensive transportation method is given by the scenario 4b configuration, in which the existing pipelines are retrofitted to transport a mixed blend of hydrogen and natural gas and with a separation step at the delivery end-location. This separation step is the heftier variable that positions this scenario separate from the rest, at least in the first 200 km. It is worth mentioning that this scenario declines more rapidly than the rest, mainly because its more significant contributor, the separation expenditures, is not dependent from the distance. That is why from approximately 230 km onwards scenario 4b starts to show even lower cost results than scenario 2 and 3.

Scenarios 2 and 3 are next in line going downward from the most high cost cases. These two scenarios are both configured such that they use newly dedicated pipelines for a 100% hydrogen stream. The main difference between the two of them is that scenario 2 considers the compression efforts at the end point while scenario 3 does so at the injection point. Although both scenarios look pretty much the same, there is a slight difference, not perceived at a simple glance from the graph: but scenario 2 is slightly more costly as a result of the compressing efforts being done at the endpoint which demands a little more power than doing it from the injection point.

Next comes scenario 5, which is driven by its methanation process converting the hydrogen to synthetic natural gas and injecting it into the existing pipeline network. For this reason, scenario 5 does not contemplate new investments in compression, a variable that had a strong impact in all other scenarios, as they use the existing infrastructure. It does consider the operational expenditures related to compression, though.

Scenarios 1 and 4a ranked with the lowest total cost per kilometre ; both scenarios set to reuse the existing infrastructure. While the first one transports a pure hydrogen stream, the latter injects the hydrogen into the current natural gas stream delivering a blended stream without considering any separation whatsoever. They both showed the same total cost, due to the fact that the maximum allowable admixing set to 15 vol% was never reached, since the amounts of hydrogen being produced were too small for that. Therefore, both scenarios are transporting the full hydrogen production available.

5.1.2. Complex Approach

This approach contemplates every variable set forth in the framework. It considers a declining natural gas profile, along with an increasing wind power capacity and consequently a growing hydrogen production throughout a time period from 2020 until 2060.

Wind Power Capacity & Hydrogen Production

The wind power capacity follows the "Rapid Development" scenario [9], where the estimated power for the years 2020, 2030 and 2050 are 2 GW, 11.5 GW and 32 GW, respectively. With a capacity allocation of 20% towards PEM electrolyzers at 75% efficiency, the hydrogen power obtained ranges from 0.34 GW in 2020 to a maximum of 5.4 GW in 2050.

Hydrogen Injection

The impact of considering a declining natural gas stream coupled with increased production of hydrogen along the project lifetime is depicted in Figure 10 below. The blue bars represent the hydrogen produced in each year, while the orange ones represent the hydrogen injected into the natural gas stream; both are plotted against the left vertical axis. On the right axis, the per cent in volume of the hydrogen injection into the gas stream is represented with a yellow line throughout the extension of the project lifetime.

It can be observed that the full production of hydrogen could be injected into the gas stream only until 2040, in which year the natural gas stream decline is such that the maximum allowable admixing per cent becomes a constraint. So, from 2040 till 2050 there is an increasing surplus of hydrogen that may not be allowed to be injected into the stream. From the year 2050 onwards as there would not be any more natural gas delivered in the pipelines, the full amount of hydrogen production is transported.

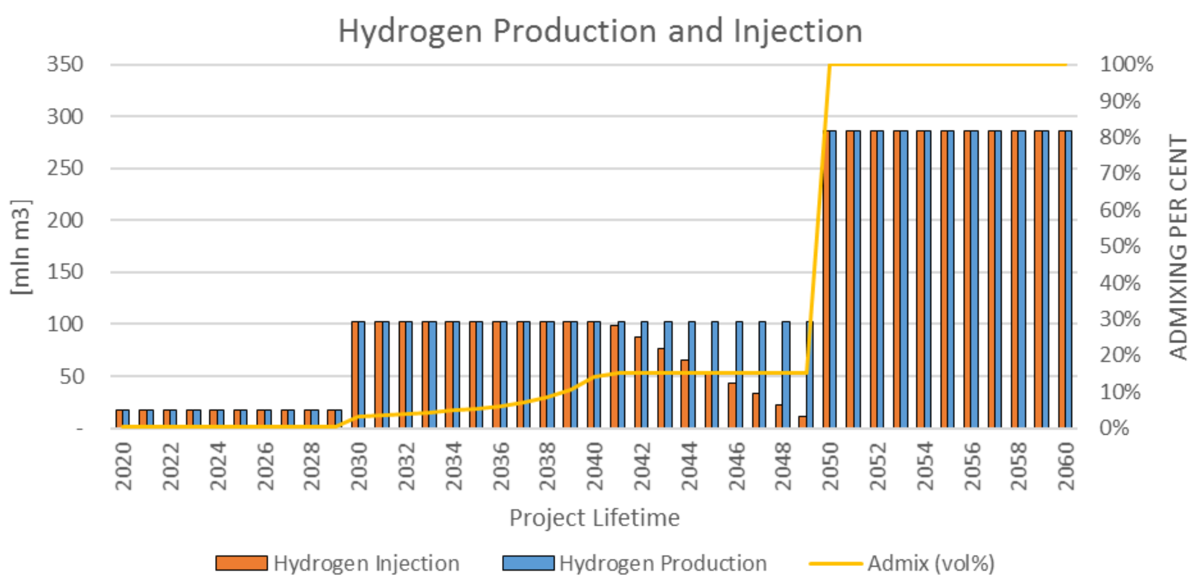

Figure 10 - Hydrogen Production & Injection (Complex Approach)

5.2. Total Costs per Scenario vs Distance (in time)

Figure 11 below presents the results in a line chart. Each line represents one of the evaluated scenarios' total costs in millions of euros per kilometre over the lifetime of the project (grouped by 20 years), and distance (in ranges of 10 km from 50 km to 300 km). The total costs for scenario 5 have been plotted against the secondary (right) vertical axis in order to get a joint overview of all the scenarios.

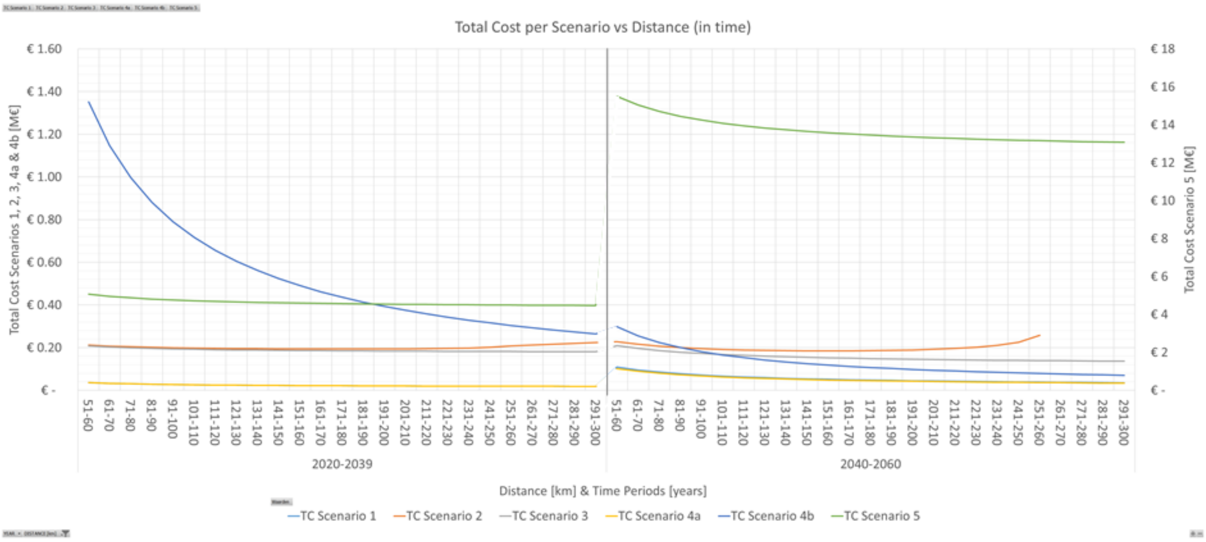

Figure 11 - Total Cost per Scenario vs Distance (in time)

The first trend that can be observed from Figure 11 is that the total costs in every scenario decrease with longer distances, which is mostly due to a decreasing impact of fixed costs on the costs per kilometre. The exception to this trend is scenario 2. Since this scenario assumes that the compression efforts are applied at the receiving end, and therefore when the pressure drop reaches values near to the initial injection pressure, the amount of compression power required for longer distances increases rapidly. Likewise, the second time period shows that the total costs increase significantly. This is due to the fact that there is more wind power capacity installed and therefore more hydrogen available to be transported.

In the following subsections, we will take a look at different timeframes and hydrogen generation capacities to get insight into the issue which scenarios may be preferable under which conditions.

5.2.1. From 2020 to 2039

Figure 12 only shows the total costs per kilometre in each scenario during 2020-2039 corresponding to a hydrogen production capacity of 0.4 GW in 2020 increasing towards 2 GW in 2030. The total costs for scenario 5 have been plotted against the secondary (right) vertical axis in order to get a joint overview of all the scenarios.

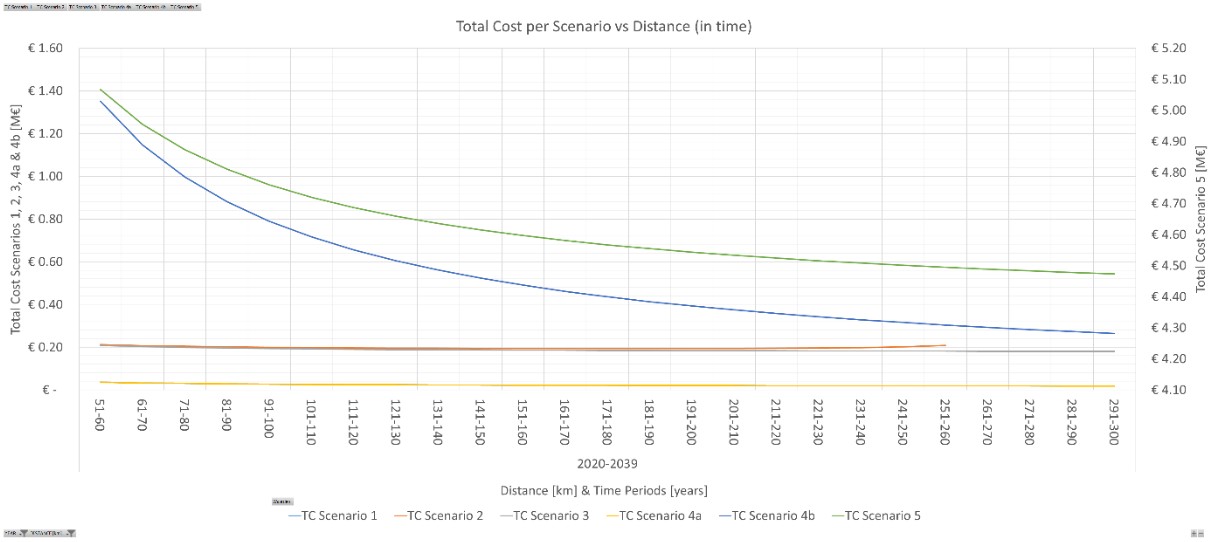

Figure 12 - Total costs per scenario vs distance (2020-2039)

An assessment of the results shows that in the first twenty years of the project, the costlier option is represented by scenario 5, even though it uses the existing infrastructure. The high costs of implementing a methanation process to convert the produced hydrogen into SNG makes it rank as by far the most expensive choice. Next in line comes scenario 4b, which also considers the reuse of existing infrastructure and transports a mixed blend of hydrogen and natural gas with a separation step before the delivery point. This last step is for the most decisive for explaining its hefty total costs. The total costs in these two scenarios are typically driven by their expenditures in methanation and separation as shown below:

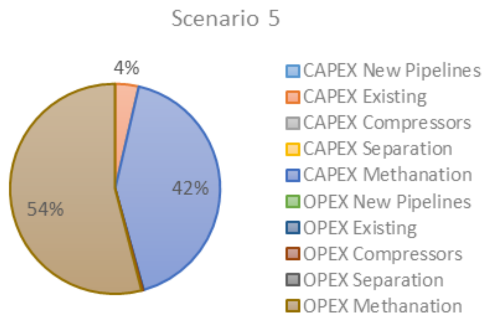

Figure 13 - Scenario 5 Total costs share (2020-2039)

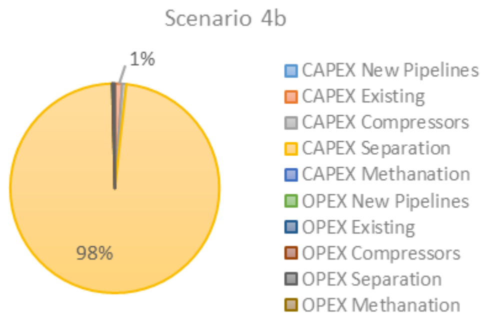

Figure 14 - Scenario 4b Total costs share (2020-2039)

Scenarios 2 and 3 follow in the ranking of costlier to less costly scenarios, which is due to their costlier investment in new pipelines and high compression costs as a result of transporting 100% hydrogen. Scenario 2 is slightly more costly due to higher compression efforts needed to overcome the pressure drop along the distances, resulting in higher capital expenditure for its new compressors. This is shown in Figure 15 and Figure 16 below:

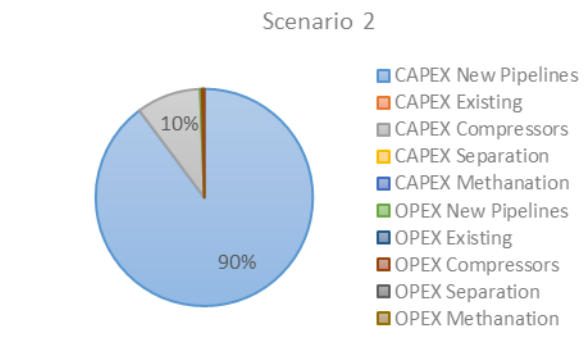

Figure 15 - Scenario 2 Total costs share (2020-2039)

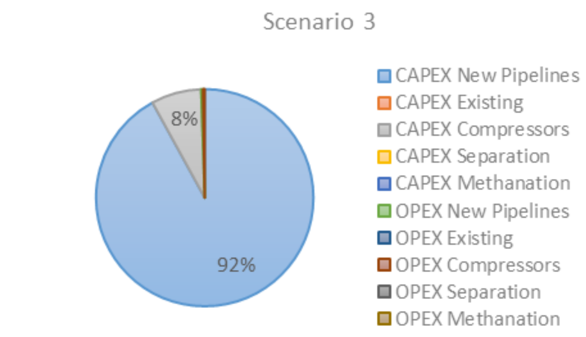

Figure 16 - Scenario 3 Total costs share (2020-2039)

Scenarios 1 and 4a are positioned on the low-cost side, mainly as a result of re-using existing infrastructure and not implementing any further step such as methanation or separation. Even though the transported stream of scenario 1 is a 100% hydrogen stream and for scenario 4a a blended composition of hydrogen and natural gas, they present the same total cost lines. This is the result of having such a production volume of hydrogen that it can be admixed into the stream in its entirety and still remain under the 15 vol% maximum share, causing both scenarios to transport the same amounts of hydrogen during the analysed time period. Therefore, the cost drivers for these two scenarios in the first twenty years are the retrofitting cost of the existing pipelines and the expenditures related to the compressors (Figure 17 & Figure 18).

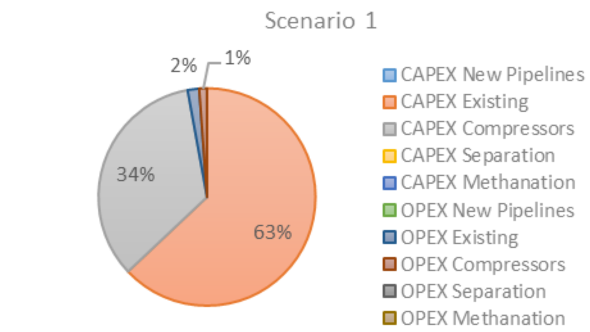

Figure 17 - Scenario 1 Total costs share (2020-2039)

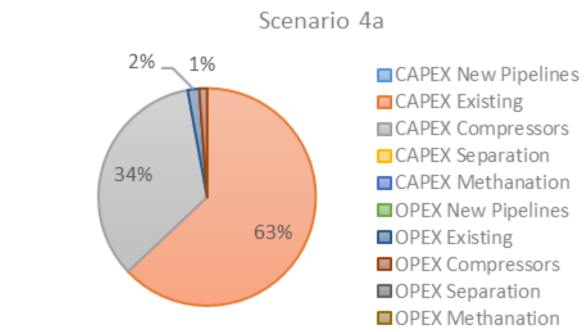

Figure 18 - Scenario 4a Total costs share (2020-2039)

5.2.2. From 2040 to 2060

Figure 19 only shows the total costs per kilometre in each scenario during 2040-2060 characterised by a hydrogen production capacity growing from 2 GW in 2030 towards 5.4 GW in 2050. The total costs for scenario 5 have been plotted against the secondary (right) vertical axis in order to get a joint overview of all the scenarios.

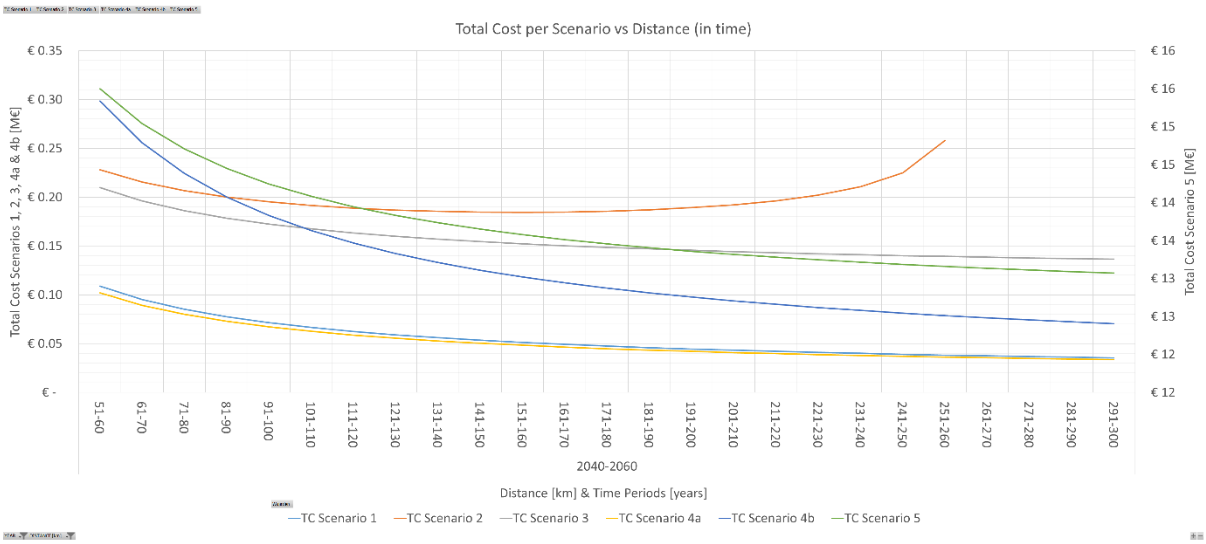

Figure 19 - Total costs per scenario vs distance (2040-2060)

Over the next twenty years of the project, in which hydrogen volumes increase and natural gas throughput diminishes, the ranking of the scenarios changes. Scenario 5 still stands as the most costly option. This is mainly due to the capital expenditures for the methanation step, which in this period have to cope with full production of hydrogen with increased capacities. Therefore, since the methanation step is directly related to the injected amounts of hydrogen, costs for methanation rise strongly as shown below:

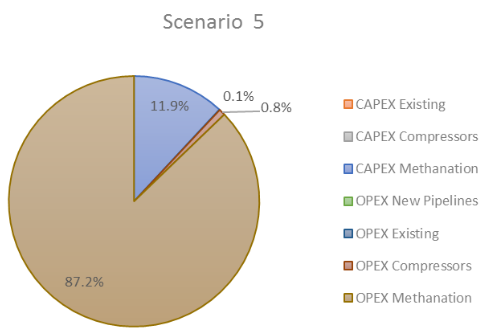

Figure 20 - Scenario 5 Total costs share (2040-2060)

The remaining scenarios are ranked. By doing so, it turns out that the scenarios that include investment in new pipelines and a 100% hydrogen stream are costlier than the rest, mainly because the amounts of hydrogen to be transported are much higher. The latter factor has a substantial impact on the compression efforts which are the main relevant cost parameters that position each of these remaining scenarios, as shown in the figures below:

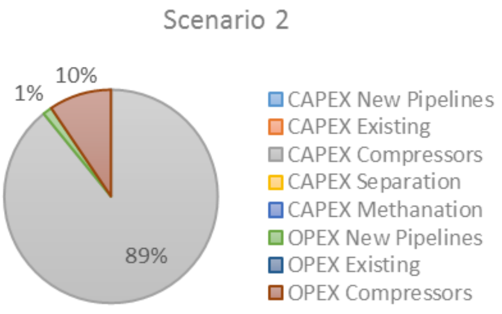

Figure 21 - Scenario 2 Total costs share (2040-2060)

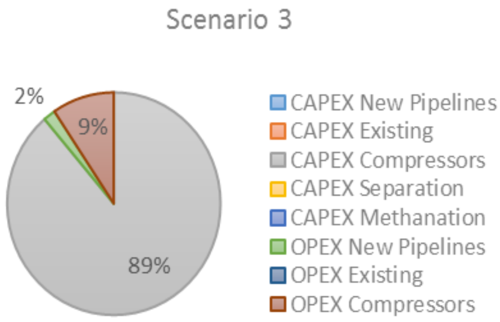

Figure 22 - Scenario 3 Total costs share (2040-2060)

Moreover, scenario 2 presents an upward increase in its total cost for distances beyond 170 kilometres. This is the result of not having a compression stage at the injection point and relying on the electrolysers output pressure to overcome the pressure drop till the receiving point where the stream is elevated to the required receiving pressure. This makes the power demanded to cope with the pressure difference even more significant due to the compressibility factor of hydrogen at lower pressures.

Next in line comes scenario 4b which considers the re-utilization of the existing pipelines and a separation step at the delivery end. In the same way as scenario 5, the main reason of heftier costs per kilometre in the first twenty years was its capital expenditures for the separation. This upfront expense is much lower during the second time period as a result of the decreasing amount of natural gas being produced coupled with the 15 vol% admixing limitation, leading to a diminished amount of hydrogen being allowed to be injected into the stream. Therefore, as the separation step is directly related to the injected amounts of hydrogen, costs for separation plunge but remain relevant as shown below:

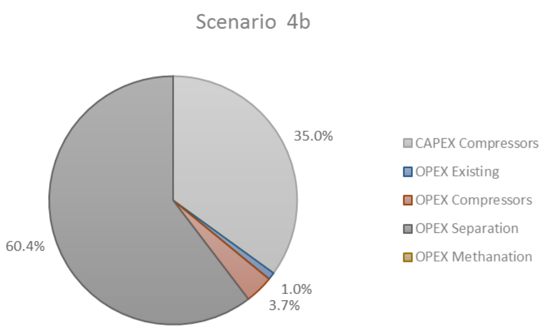

Figure 23 - Scenario 4b Total costs share (2040-2060)

Scenarios 1 and 4a are on the lower-cost end . Both consider the use of existing pipelines but differ in the transported stream: compressing the blended stream of scenario 4a is slightly less demanding than the 100% hydrogen stream of scenario 1. Therefore, the main parameters driving these scenarios during this time period are the compression related costs as shown below:

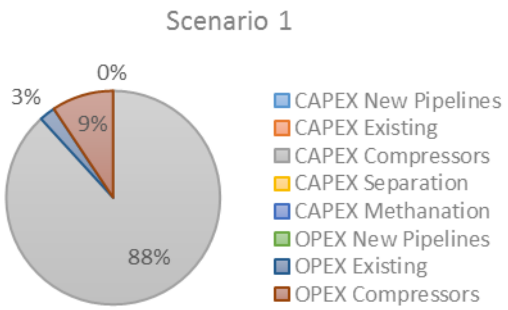

Figure 24 - Scenario 1 Total costs share (2040-2060)

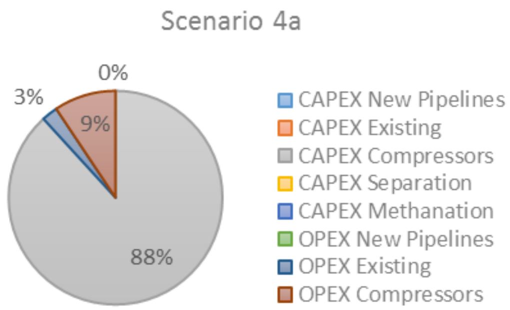

Figure 25 - Scenario 4a Total costs share (2040-2060)

From 2020 to 2060

The previous analysis showed how the total costs of each scenario developed during the different periods of time. Now the aim is to add to the previous outcomes a comparison of the overall cost of every scenario throughout the entire lifetime of the project. This is done by calculating the Net Present Cost of each of the scenario.

5.2.3. Net Present Cost

Given that the capital expenditures in every scenario are highly related to the length of the pipelines, a representative 100 km length has been selected to get to results comparable between scenarios.
The results of a life-cycle cost assessment per scenario, by way of the present value of all the capital and operational expenditures over the lifetime of this study from 2020 to 2060, are depicted below.

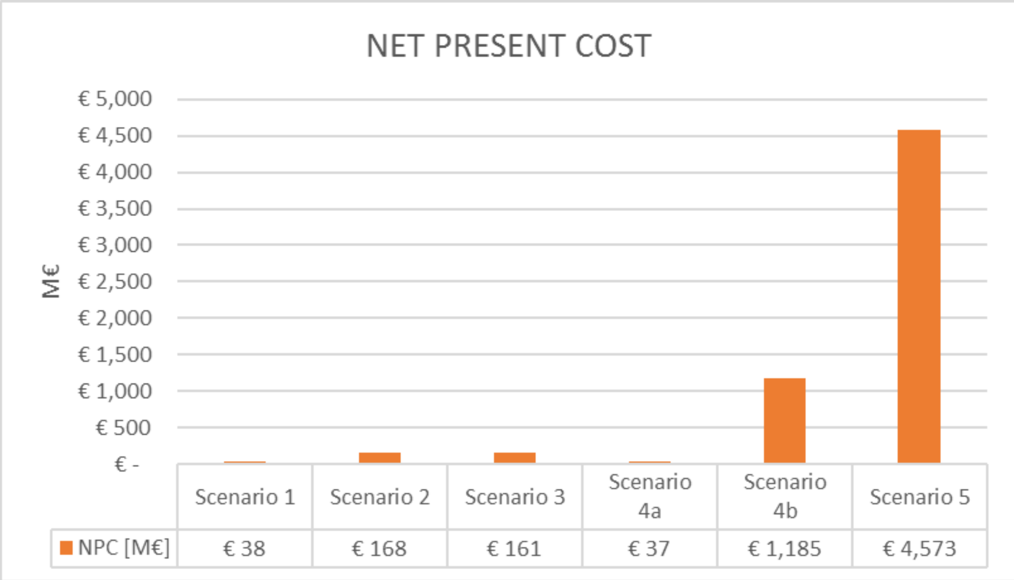

Figure 26 - Net Present Cost

These results demonstrate that scenarios 4b and 5, which are based on existing infrastructure and an admix blend that is separated and methanized into SNG, respectively, are the costliest option mainly due to the high cost of the separation and methanation steps.

Next in line are scenarios 2 and 3, respectively. Both scenarios assume new infrastructure investment and a 100% H_2 stream. Scenario 2 ranks costlier due to its higher compression efforts compared to scenario 3.

At the lower positions are scenario 1 and 4a. Both assume the use of existing infrastructure but differ with respect to stream compositions. In scenario 1 a 100% H_2 stream is transported and in scenario 4a a blended stream. This is the main reason for the different net costs between them, as the volumes in scenario 1 increase along the lifetime of the project due to increasing hydrogen production, while the flow rate of scenario 4a decreases due to the diminishing natural gas production and the impact of the admixing constraint (see Figure 10) and consequently lower compression efforts needed.

5.2.4. Levelized Cost of Energy (LCoE)

In the preceding sections, the results and analysis were based on total costs per kilometre in each scenario. It gave some impression of cost levels per scenario but not how much energy is delivered. It also gave an indication of the investments involved. However, it is worth also to consider how much energy is transported given such investments. So, a cost comparison per unit of energy transported will be performed with the help of an LCoE analysis based on high heating values (HHV) of the gas mix. The LCoE (transported) results are depicted in Figure 27 below. They show that scenarios 4b and 5 are the ones with the highest cost per transported MWh, due to the high capital investment required for the separation and methanation steps. Next in line come scenarios 2 and 3, which assume new infrastructure investment, thereby positively impacting cost per unit of energy transported. Out of this group, scenario 2 presents slightly higher costs due to higher demand for compression power.

After that, scenarios 1 and 4a present the lowest cost per transported unit of energy as a result of their assumed reuse of existing infrastructure and therefore smaller upfront investments. Scenario 1 shows somewhat higher costs than scenario 4a because in the former the full production of hydrogen can be transported each year, while in scenario 4a flow rates are lower because less energy is transported. The latter is due to a decreasing amount of natural gas produced, and its consequence via the allowable admix ratio (see Figure 10).

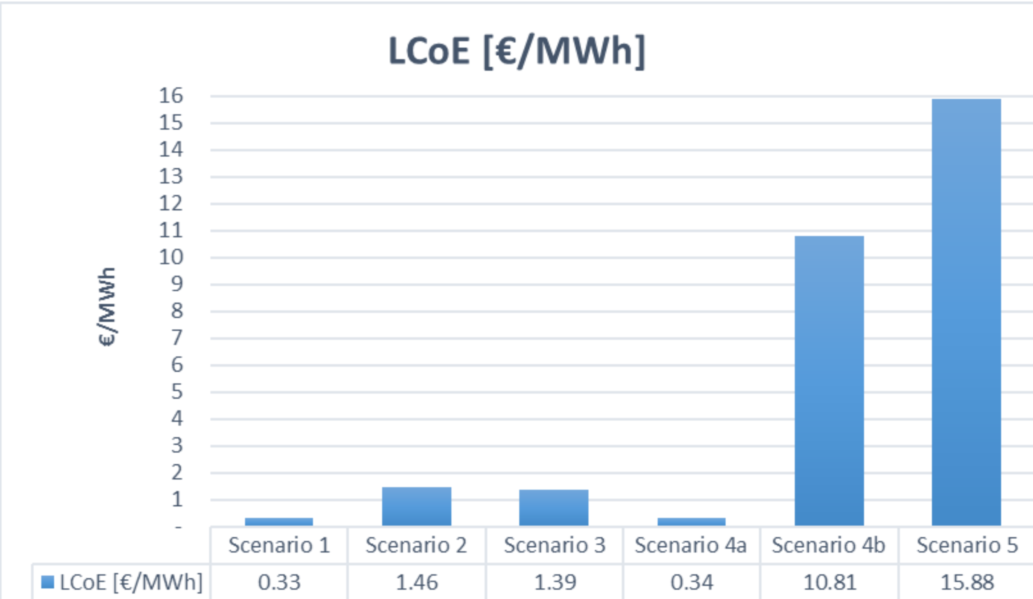

Figure 27 - Levelized Cost of Energy (transported)

The results obtained must be interpreted with care. At first glance, it looks like scenario 4a is the most logical and economical transportation method due to its lowest cost per unit of transported energy. But then again, due to the inherent constraints of this scenario, mainly the allowable admix per cent, not all hydrogen produced can possibly be transported, or even stored, so that other, often costly, solutions will have to be found. These costs are not taken into consideration, but will definitely affect this particular scenario's cost profile.

6. Conclusions

This study assesses cost profiles of various transportation modes of bringing green hydrogen produced offshore in the Netherlands Continental Shelf (North Sea) to shore (transport options of so-called blue hydrogen were not included in the study). The aim was to identify cost differentials and to explain which techno-economic cost parameter values are the most critical ones for each transport mode. The model developed for this purpose typically allows to compare transport costs under varying transport capacities and distances.

In order to compare the various scenarios' results in a long-term perspective, a 2060 time horizon (starting in 2020) was set with an intermediate step in 2040. Based on the literature, offshore green hydrogen production on the Netherlands Continental Shelf (0.4 GW in 2020) was assumed to amount to 2 GW from 2030 onwards and 5.4 GW from 2050 till 2060.

The most important findings were the following:

The lowest-cost transport mode of green hydrogen to shore was to transport it along with the conventional natural gas flow via an existing gas pipeline system without separating it later on. This way - assuming a 100 km transport distance and hydrogen volumes increasing from 16 (2020) to some 250 Mm3 (2050) - transport costs amounted to some € 0.011 per kg of hydrogen. The backdrop of this option is that the hydrogen may only generate a price comparable to the relatively low natural gas price, but may in addition generate a premium for the green certificate generated. Also in a possible future regime in which admixing a certain % green gasses to natural gas would be mandatory, this option may be attractive.

Transport costs per kg of hydrogen only slightly increased, primarily due to higher compression costs, in the mode in which instead of admixing to natural gas a 100% hydrogen flow was transported by reusing an existing pipeline system. The critical point of this transport mode – next to possible safety issues – is whether suitable existing gas infrastructure will be available in time given exploration time profiles. A co-benefit of this mode would be that it offers some storing potential (line-pack) without significant extra costs, and therefore contributes to produce green hydrogen from otherwise curtailed or stranded wind energy.

Overall transport costs of the third and fourth transport mode considered – either admixing the hydrogen to a natural gas flow via an existing gas grid to separate it again once onshore, or transporting pure green hydrogen via a new dedicated transport system – obviously were considerably higher than the first ones (i.e. without separation or new infrastructure needed) mentioned. Which of this two modes had the lowest costs per kg/km turned out to typically depend on the green hydrogen volumes transported per time unit and the transport distance. On the whole investment in a new dedicated hydrogen pipeline turned out the more cost-effective, the larger the hydrogen volume to be transported and the longer the distance to shore. The main conclusion, however, from a levelized cost of energy perspective was that the cost of the option to transport the hydrogen via a new dedicated pipeline system was significantly lower than the cases of admixing and separation. Typical transport cost levels per kg of hydrogen were € 0.05 for the case of investment in new pipelines, but as much as € 0.36 for the transport mode that includes a separation step onshore while reusing the existing pipeline system. In fact, separation costs in some cases represented as much as 98% of overall transportation mode costs.

A final transportation option including offshore methanation of the green hydrogen flows (e.g. because in due time hydrogen volumes threaten to surpass the max. admixing rate), if at all technically feasible given the available offshore space, turned out to be much (some 30 times) more expensive than options including transport via new dedicated hydrogen pipeline systems, and was therefore regarded non-feasible.

As far as the admixing transport modes is concerned, it could be concluded that even in a very optimistic scenario of the Netherlands' North Sea wind power development the risk of surpassing the assumed admixing maximum allowed limit of 15 vol% turned out to be very small, at least until 2040. Whether risks of violating this threshold may grow after 2040 obviously also depends on the future policy regime towards max. offshore admixing.

More in general, sensitivity analysis on cost components showed that compressor costs were among the most decisive cost factors in all scenarios, both if existing infrastructure was reused (cost share 14% on average), or in cases of new dedicated pipelines (shares between 37 and 40%). New, more efficient hydrogen compressor or (high-pressure) electrolyzer technology may therefore have a serious downward transport cost impact.

6.2 Recommendations

As the outcomes of this study show, there is not just a single transportation method turning out to be the most cost-effective option for varying transportation distances and volumes transported. Instead, each of the scenarios proves to have its strengths and weaknesses, depending on the chosen parameters. This leads to the remaining question of how the gained insights could be used for the actual Dutch situation on the North Sea. In that regard, the generic approach to the topic of hydrogen transportation allows to proceed in greater depth in a next study.

In particular, the generic framework developed in the course of this first project could be applied to specific offshore locations. The proposed approach would be to base the study on projections for offshore wind farm locations since these sites present themselves as high potential offshore hydrogen production locations as well.

A second point to be considered is the expansion of the original system boundaries in order to assess the value of the transported molecules next to the costs of transportation. The value comprises both the economic value as well as technical value characteristics such as the purity levels. This becomes important when considering e.g. comparisons between designated hydrogen transport and the transportation of methane, including either small volumes of admixed hydrogen or being the product of green methanation (scenario 4 & 5). In addition to the impact of transportation methods on costs per transported kilometre, the scenario specific impact on the cost-price per kilogram of hydrogen should be analysed.

Thirdly, the outcomes show that certain scenarios are less favourable than others. In order to avoid a premature decision on excluding the most costly transportation options (methanation) from further location specific considerations, these scenarios should be further scrutinized. The initial sensitivity analysis has already pointed out the most decisive parameters for the scenarios individually, e.g. separation costs of hydrogen from natural gas for scenario 4b. In case the earlier observations can be confirmed, the focus of a next study should consequently lay on the most economically viable transportation options and a further specification of their cost models.

In addition to earlier considerations on specific transportation locations, once can analyse the direct onshore absorption capacity of markets depending on the onshore landing points of the molecules, i.e. the receiving gas treatment plants of existing offshore pipelines. The inclusion of flexibility impact caused by new pipelines may generate additional value that is currently not taken into account,

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Annex I – Technical Discussions

Admixing - Wobbe Index

The standard WI bandwidth currently specified for the exit points in the gas transmission line for the H-gas system is 47-55.7 MJ/Nm³ [22]. The WI is a measure of interchangeability of gasses for different burning systems. Hence industrial and household appliances may not work properly if the WI decrease below the stated bandwidth.

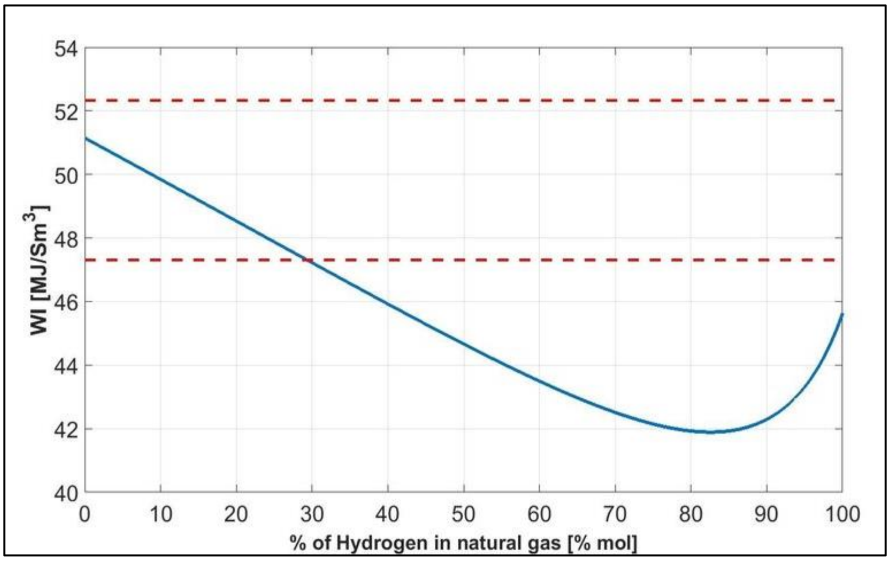

Figure 28: WI variation with injection of hydrogen, retrieved from [18]

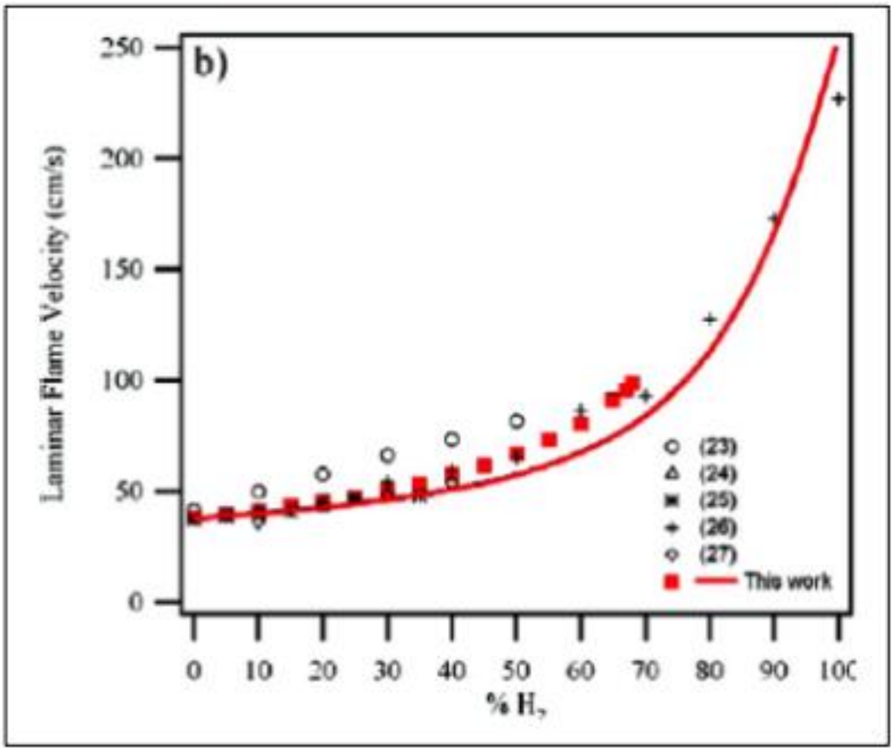

Figure 29: Change in burning velocity as a function of H2 in the gas, retrieved from [23]

Methanation

In the following section, the methanation techniques will be addressed, as well as the determinants required to use them in an offshore environment. Within the Store&Go project various literature and economic analysis have been made with regard to the various methanation technologies This was not easy, since methanation technology is still in its development phase, and information on costs of methanation reactors is even more limited than it is for electrolysers.

Technology

The methanation process could either be based on a chemical or biological reaction. The former requires a catalyst reactor, for instance nickel or ruthenium; an advantage of nickel is its high activity and methane selectivity and its material price, a disadvantage is, however, its purity request for hydrogen. Although the catalytic methanation reaction has been known since 1902 novel reaction concepts are required to operation in dynamic and intermittent environments.
The methanation reaction is highly exothermic, and thus releases energy as heat. For instance, assuming a Gas Hourly Space Velocity of 5000 h^{-1} and a complete CO_2 conversion, approximately 2MW heat per m^3 of catalyst needs to be removed [19]. The catalytic methanation reactors are typically operated at temperatures between 200°C and 550°C and as a consequence temperature control is necessary to prevent thermodynamic limitation and catalyst sintering [19]. Steady state reactors, such as fixed bed fluidized – bed, three phase and structured reactors have been developed to realized proper temperature control. Moreover, currently left out of scope, release heat may be reused in other processes.
The chemical methanation process can either be operated dynamically or steadily. The operation strategy chosen affects the requirements set to the methanation reactor and catalyst. Aspects such as stand-by characteristics of reactors, the ability to react to high temperature variations, and the speed in which reactors may ramp-up or ramp-down ultimately determine the potential of reactor to suit to dynamic conditions. If conditions are not being met, temporary hydrogen storage may secure a more stead production line. In this research it is assumed that methanation reactors are fitting these dynamic conditions, or otherwise, the hydrogen will temporarily be stored in the line-pack.

There are several challenges that affect the viability of this methanation process in an offshore location. First, the relatively high-temperature heat could, in onshore applications, be reused in industry or local district heating. It is uncertain whether it could be reused in an offshore location. If not, this would significantly reduce the overall efficiency of the methanation process. Second, the fact that the methane reactor is connected to a fluctuating primary source of energy, offshore wind, implies that the production process of the reactor is more likely to fluctuate. This may imply additional cost for hydrogen storage and therefore raise the overall cost of methanation. Third, chemical methanation is a favourable technology for large-scale industrial processes. Given the space limitations of platforms, sufficient economics of scale may not be realized leading to higher costs as well. Finally, the reactor requires a pure stream of CO_2. In the next section the complexity of this will be discussed in more detail.

A second methanation process makes use of micro-organisms (achea) and is called biological methanation. The achea obtain the energy of growth by anaerobicically metabolising hydrogen and carbon dioxide [19].

A big advantage of biological methanation is its tolerance for relatively high level concentrations of impurities, reducing the need for a very pure stream of CO_2 [19] [24]. Moreover, contrary to chemical methanation, the biological process takes place under moderate conditions with low temperatures (20°C -70°C) and ambient pressures. However, the technical implementation, such as the reactor efficiency, is still an issue. The methanation reaction takes place in the aqueous fermentation liquid. However, at 60°C, carbon dioxide is nearly 23 times more soluble than hydrogen[19]. The enhancement of mass transfer by improving the hydrogen supply to the micro-organisms presents currently the biggest engineering challenge.

Biological methanation can take place via a separate reactor or within a biomass digester. Biological methanation via a separate reactor is still in the development phase, as the supply of hydrogen to the micro-organisms significantly limits the methane formation rate. The method may become promising if future research enables a reaction between gaseous hydrogen, the microorganisms and the potential to add multiple sources of CO_2. The option for offshore biological methanation in a separate reactor is, although potentially promising, left out of the scope of this research since it is not yet commercially available. In this option, hydrogen can be fed into a biomass digester to convert part of the CO_2 (normally 40%) into methane. The methane formation rate of this option is limited by CO_2 production rates of the biogas plant. This condition affects the viability of its application in an offshore location. In our case, a biogas plant should at least be able to deliver 350 tons of CO_2 per year. This is even more challenging since current pilot-sites of biological methanation technology are still below 1 MW.

A technological comparison

Reactor type	Biological methanation (separate) isothermak CSTR	Chemical methanation fixed bed adiabetic
Stage of development	Lab-scale	Commercial
T in °C	20-70 °C	300-550 °C
Gas Hourly space velocity in h^{-1} (given that methane content >90% and product gas is dry basis.	<<100	200-5000
Tolerance for impurities	High	Low
Load change rate	Limited to process control system	Most sensitive to dynamic operation
Minimum load	No load basis needed	Minimum of 10-20%
Heat utilisation	Poor	Very good

Table 8 - comparison of main characteristics of methanation technology - retrieved from [19].

Gas hourly space velocity (GHSV) is a measure to directly compare the required reactor size of biological methanation with chemical methanation. The stark differences in GHSV's between biological and chemical methanation is caused by the fact that the methanation process is occurring under higher temperatures which leads to higher reaction rates. Moreover, the liquid phase in the biological methanation process influences the volumetric mass of hydrogen required, for reasons explained above. Biological methanation is more robust against impurities than chemical methanation. For chemical methanation process contamination with sulphur content above >1ppm could harm the nickel catalyst significantly. The flexibility of a methanation reactor is determined by the load rate change and the minimum required load levels set by the reactor technology. Comparing the two technologies is seems that the biological methanation is better suited for dynamic processes, as the limiting factor is only the process control system and no issues with rapid temperature changes are documented [19].

Carbon sources

An argument that is often used against the use of fossil CO_2 sources for methanation is that this could legitimize the continuation of fossil-fuelled power plants. This can be an issue for coal-fired power plants; for some industrial sources, one can however argue that this argument is less relevant when there are little or none green alternatives. In fact, the re-use of sources from such industries usually requires, apart from capturing, some expensive upgrading to remove poisoning trace gases. The efficiency to capture and upgrade CO_2 to a high purity stream leads to cost estimates between 14 and 100$/ton CO_2 [29]. Figure 28 provides an overview of the capture costs and their bandwidth.

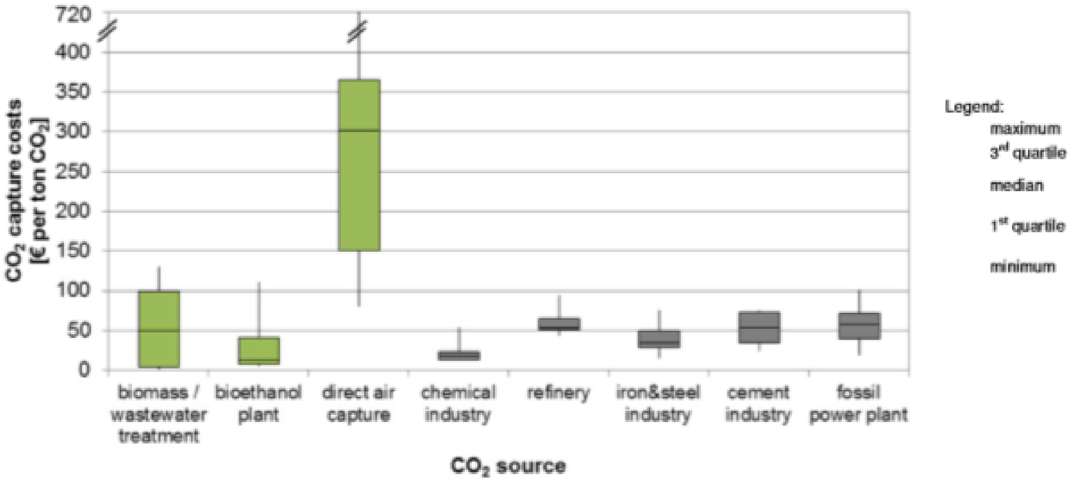

Figure 30: Costs for CO2 capture from various resources (retrieved from [29]*)*

Apart from capturing CO_2 during the combustion at a natural gas fired power plant, CO_2 can also be retrieved at the beginning of the gas value chain. Certain gas fields in the Dutch continental shelf contain a relatively high percentage of CO_2. For instance, at the K12-B field CO_2 is reinjected into the gas reservoir that simultaneously extracts natural gas. Although the injection of CO_2 increase the pressure in the gas reservoir, it may also mix up with the gas molecules, so that the process equipment may at some point no longer be suitable for processing the gas due to a too high concentration of CO_2. Hence, from that point onward the CO_2 may rather be used for methanation purposes. The advantage of the latter option is that the CO_2 is relatively cheap and does not have to be transported over long distances. The gas composition of the North Sea gas from the fields close to the future wind energy areas show, that at some gas wells the CO_2 content of the gas exceeds 20%. Here separation of CO_2 is required in order to comply with the G-Gas quality requirements. Such CO_2 streams could become available for post-synthesis (methanation) of hydrogen.

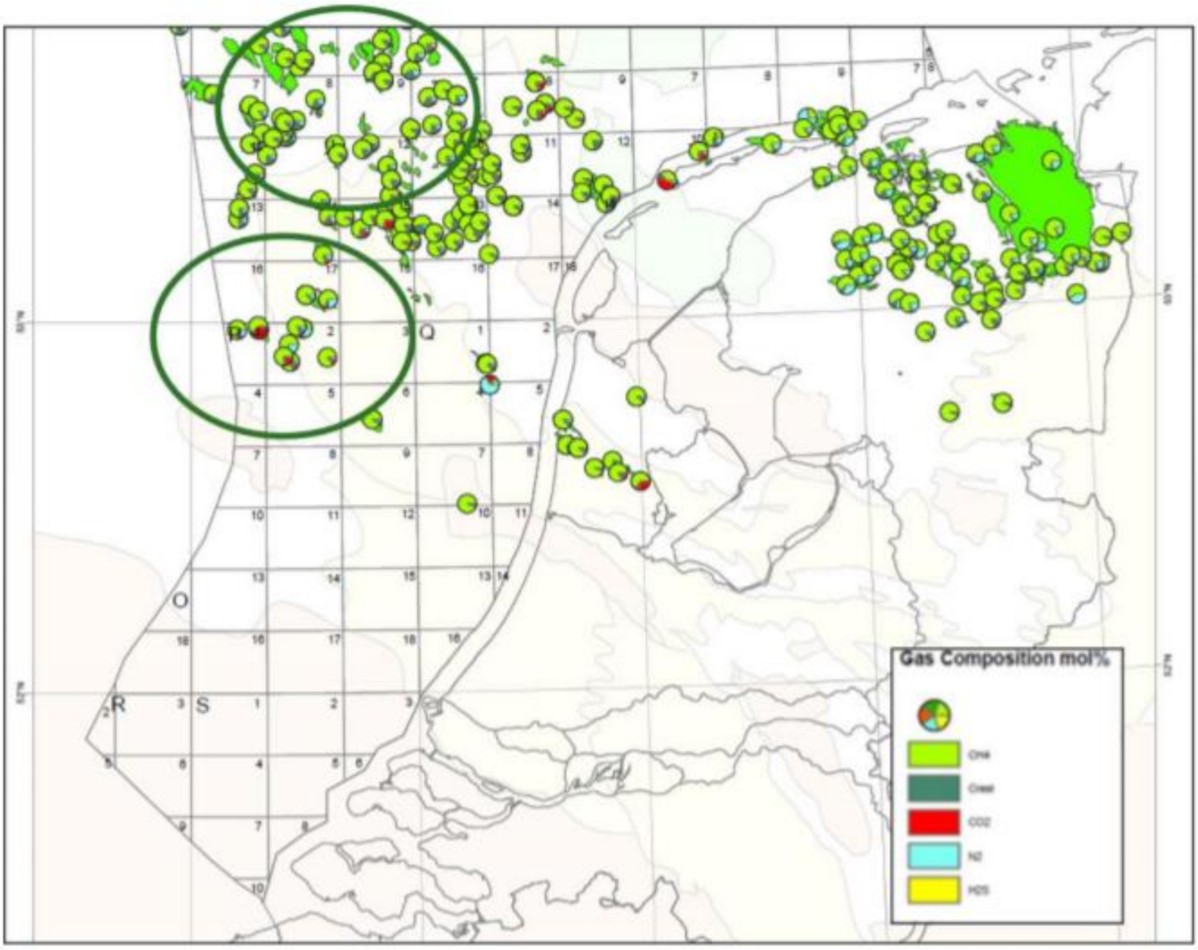

Figure 31: Gas compositions of designated gas fields close to IJmuiden Ver, and (designated) future wind energy areas, retrieved from [25]

Biomass as a source of CO_2

The use of biogas and biomass as part of the power-to-gas chain has the advantage that gas cleaning expenses are low. In case of an offshore biomass-to-gas plant, the O_2 from the electrolyser may be used in the gasification process to increase the efficiency of the overall process [19].

From a socio-economic perspective biogas may be seen as the most ideal CO_2 source, although in practice the average size of the CO_2 sources is rather small. Moreover, if CO_2 sources are located at a larger distance - which is likely since realisation of biogas/bio-ethanol offshore is even more costly than onshore - transport costs of CO_2 should be included. An overview of the CO_2 capture costs from biogenic sources is given in Figure 28.

Although locating a biomass gasification plant offshore would in theory be possible, this would pose a number of challenges. First, there should be enough feedstock for a continuous production of biogas. Although seaweed could function as a feedstock, it has a rather small energy content and should be cleaned up front. Moreover, using it as an energy crop implies its competition with other seaweed markets such as for nutrients, chemicals, sugar, and food. Such markets would probably generate higher prices for sea weed than if used for energy applications.

Direct air capture

The main advantage of separating CO_2 directly from the air is that it can be done at nearly every location, basically just depending on available space. On the other side, the concentration of CO_2 in the atmosphere is only some 400 ppm, making CO_2 capture from air a rather energy-intensive process. Companies like ClimeWorks[23] are working on this, but at its current stage it still is an immature, expensive and energy consuming technology. For the extraction plant in Troia (Italy) CO_2 production costs from air are in the order of 80-120t/CO_2 ; for commercial scale plants with favourable energy costs (e.g. low price for waste heat of 100 degrees) costs are likely much lower.

23 http://www.climeworks.com/our-products/

Annex II - Sensitivities

In an effort to test the robustness of the results, one-way sensitivities analysis were performed to a set of parameters in order to understand how much each of them affects the total Net Present Costs. Most of the parameters were selected on the basis of their assumed contribution to the total costs; some parameters because of uncertainty towards their future values. So, the following parameters (see below) were subject to increases and decreases by 20 and 50%, resp. to assess their impact on NPC.

The following graphs show the impact of parameters values (in % of change of NPC) per scenario when stressed to a -/+ 50% and a assumed length of 100 km.

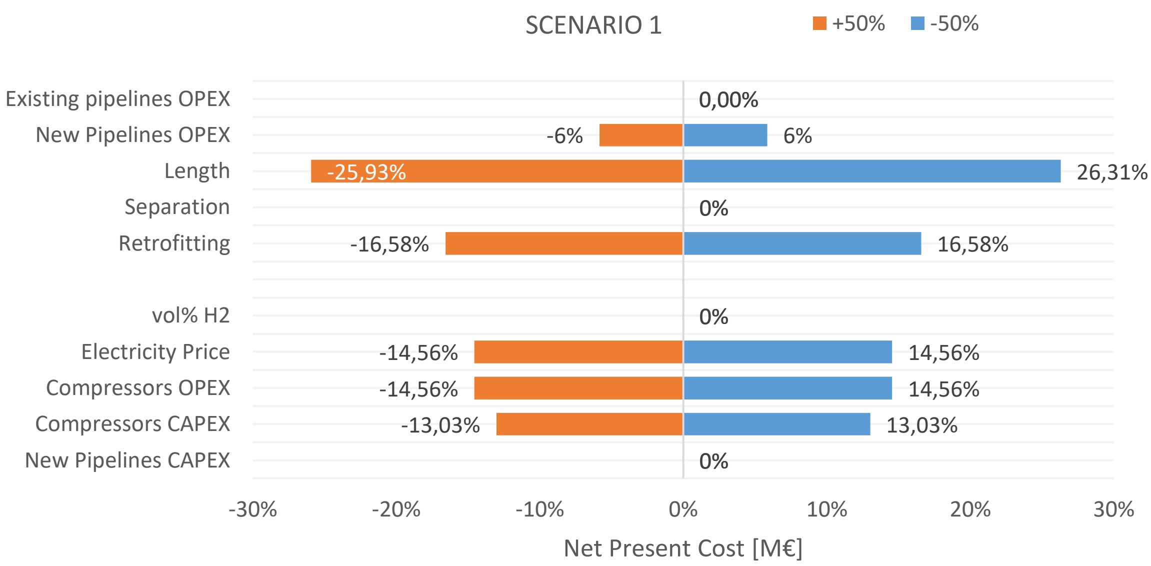

Figure 29 - Scenario 1 Sensitivity Analysis (±50%)

Scenario 1 assumes the reuse of existing pipelines. Therefore the prime cost drivers are the existing pipelines retrofitting costs expenditures closely followed by the compression expenditures.
The electricity price has a direct impact on the compressors' OPEX; hence they yield the same effect.
The pipe length variations show how costs vary depending on whether one assumes a 50 or 150 km arrangement.

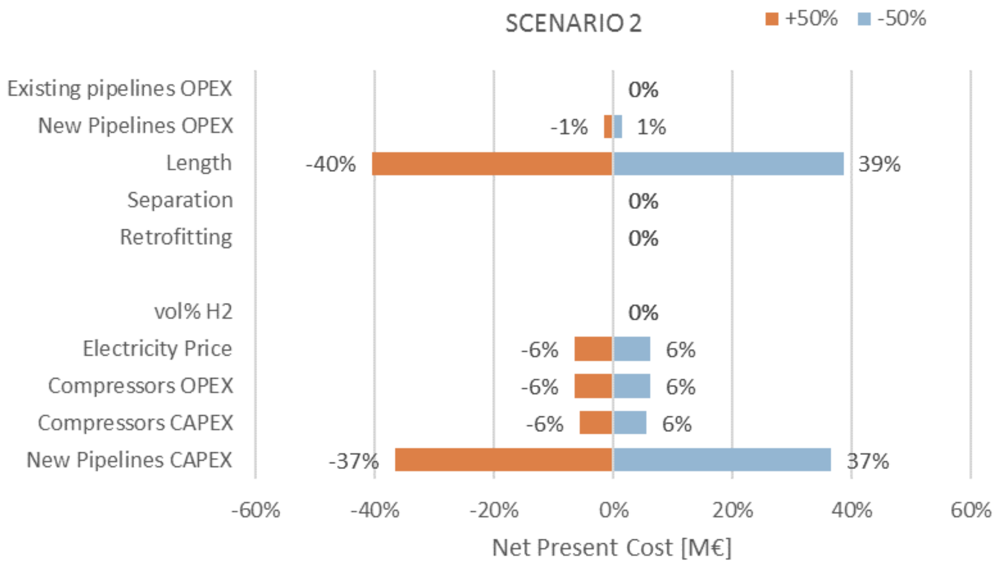

Figure 30 - Scenario 2 Sensitivity Analysis (±50%)

Since scenario 2 assumes investment in new pipelines, their CAPEX plays the largest impact on NPC. Next in line comes the compressors expenditures continue to have a significant role in the sensitivities. The electricity price directly affects the compressors' OPEX and therefore have the same impact. A similar pipeline length sensitivity was carried out as in the former case.

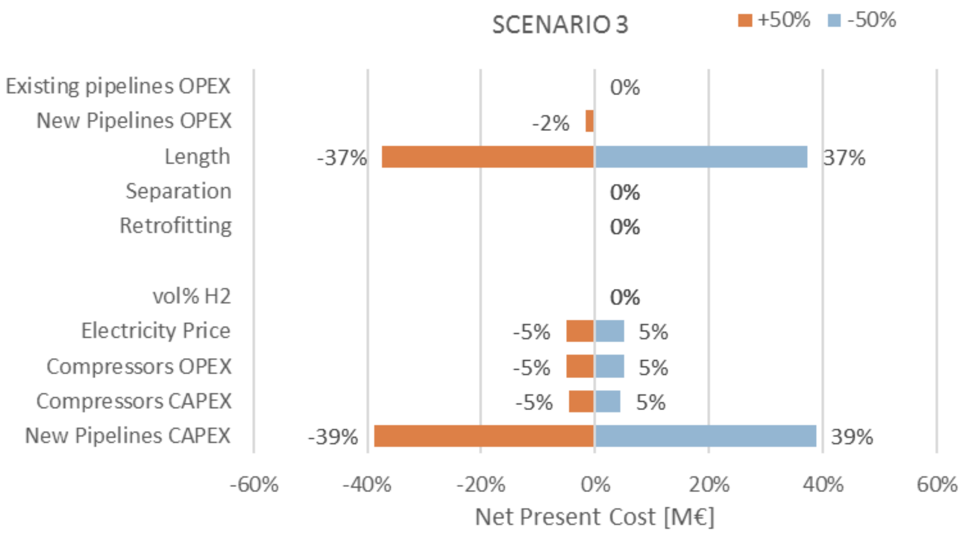

Figure 31 - Scenario 3 Sensitivity Analysis (±50%)

The parameters in Scenario 3 behave pretty much the same way as in the previous scenario, with the difference that the New Pipelines CAPEX exercises a more significant influence due to the fact that in this scenario the pipe diameter is larger.

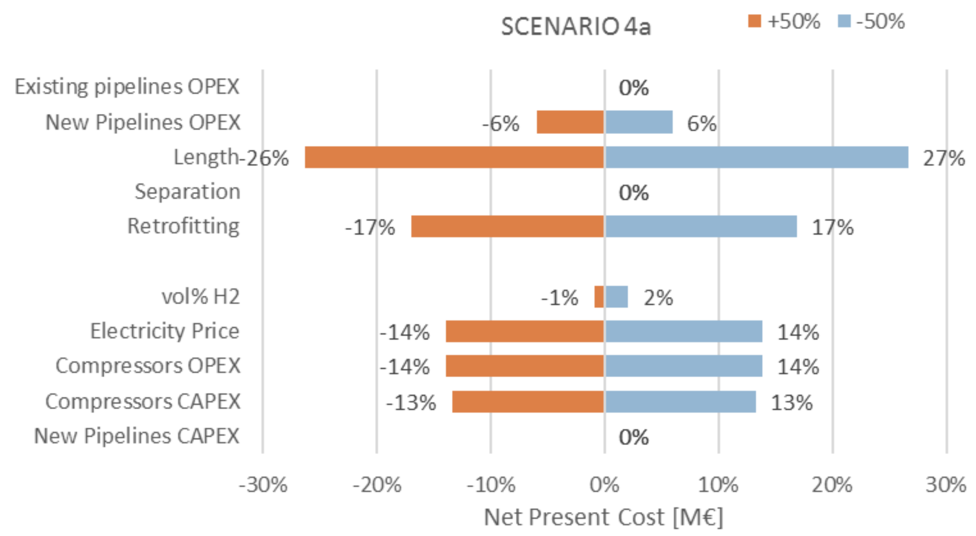

Figure 32 - Scenario 4a Sensitivity Analysis (±50%)

Scenario 4a presents very similar sensitivities as in scenario 1. The slight differences between these two scenarios is the result of a blended stream being transported in scenario 4a requiring less compression efforts.

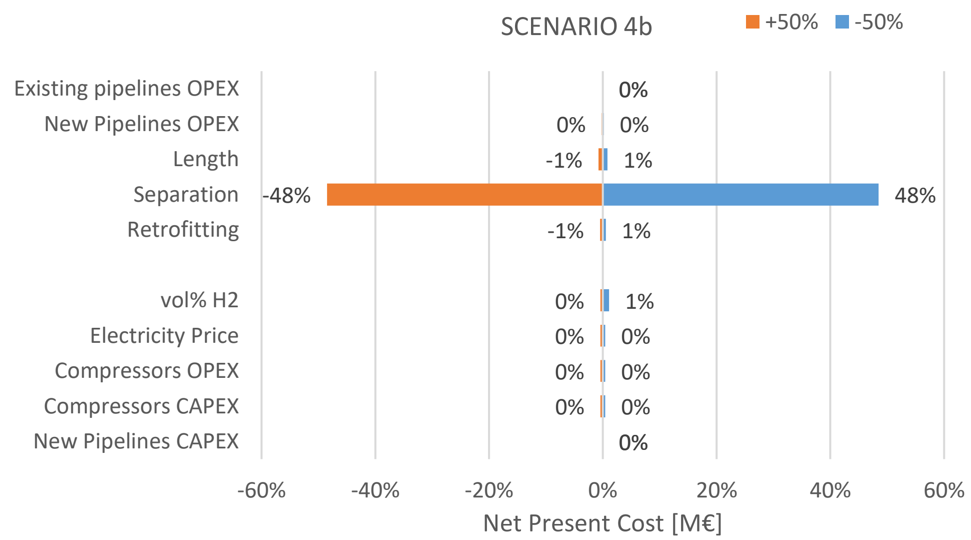

Figure 33 - Scenario 4b Sensitivity Analysis (±50%)

Scenario 4b has a clear driver to its NPC, which is the separation expenditures.

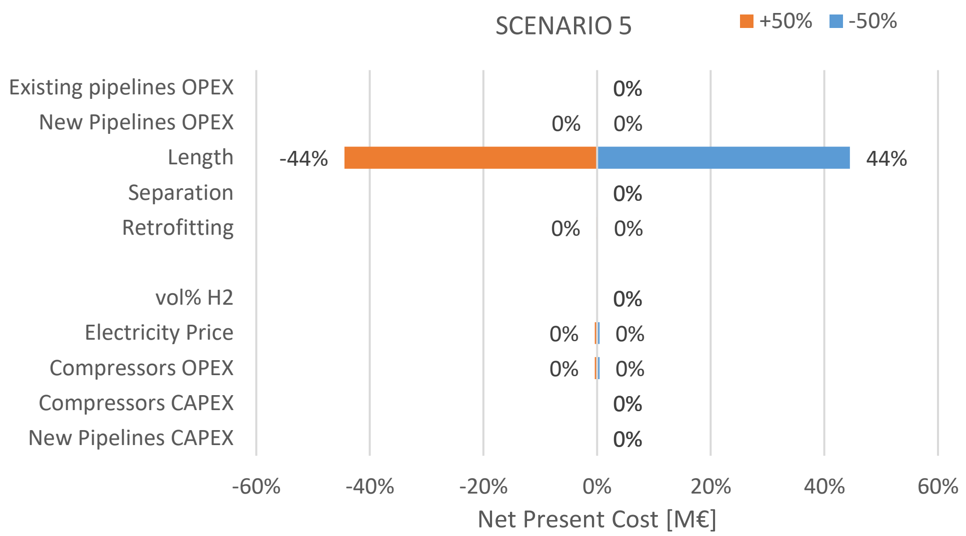

Figure 34 - Scenario 5 Sensitivity Analysis (±50%)

Scenario 5 has a clear driver to its NPC, which is the methanation expenditures.

All in all, the most significant parameters according to their impact on the Net Present Cost of each scenario are: the Compressors' CAPEX and OPEX, the New Pipelines' CAPEX, and separation costs. A representation of their impact is given in the charts below.

It is worth mentioning that variations in the max. % admixing do not seem to exercise a substantial impact on the scenario results. In fact, the analysis showed that an increase in the max. allowable admix % even has a negative impact on the NPC, by making it costlier (due to needing more compression and separation costs).

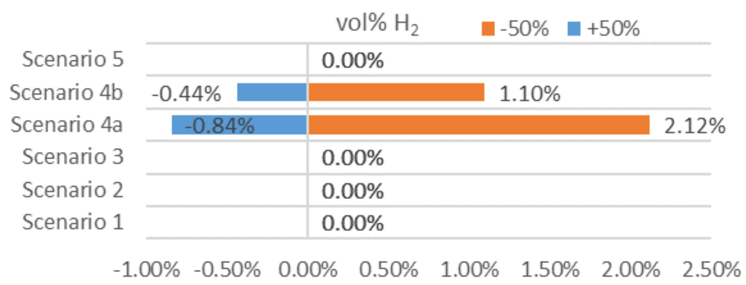

Figure 35 - Sensitivity Analysis on the Maximum Admixing Per Cent (±50%)

Compressors expenditures have proven to be significant in almost every scenario, but scenarios 4b and 5. The reason behind this is that in scenario 4b the costs of the separation step are so high that make all the other variables less relevant. For scenario 5, since it is considering a methanized stream of SNG, there is no need for investment in new compression facilities.

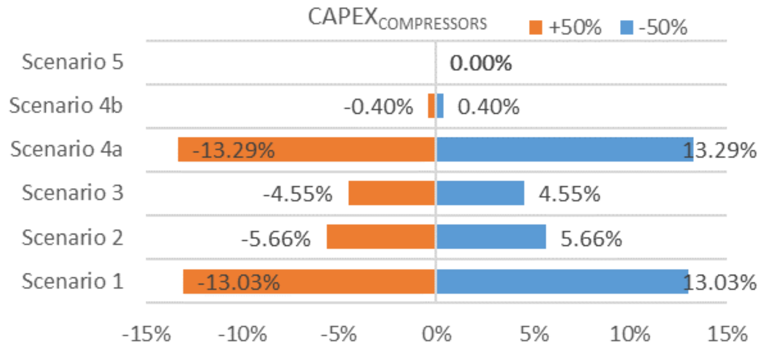

Figure 36 - Sensitivity Analysis on Compressors CAPEX (±50%)

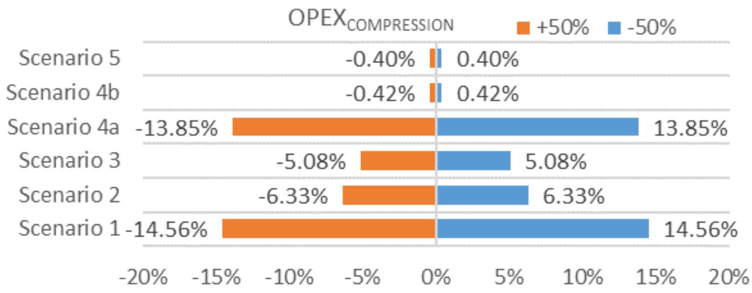

Figure 37 - Sensitivity Analysis on Compressors OPEX (±50%)

The investment of new pipelines is consequently only relevant in those scenarios in which it is considered the installation of new pipelines. Therefore, scenario 2 and 3 present a high dependancy on the new pipelines expenditures as shown in Figure 38.

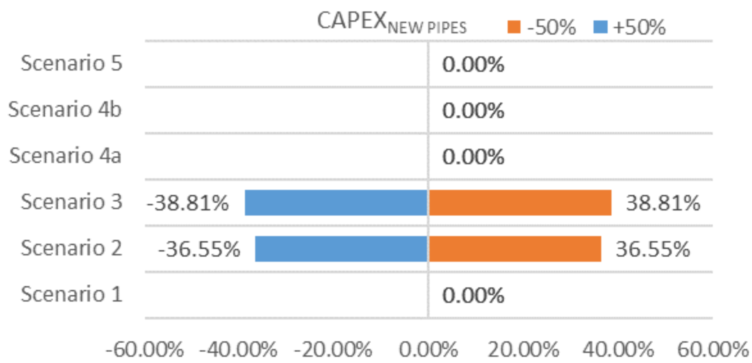

Figure 38- Sensitivity Analysis on New Pipelines CAPEX (±50%)

Confirming what has already been discussed along with other sections of this study, the separation costs are incredibly dominant in scenario 4b as shown below in Figure 39.

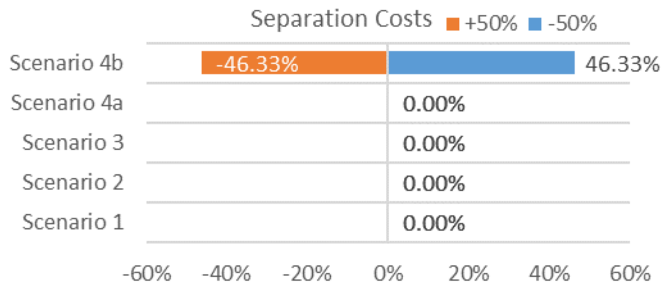

Figure 39 - Sensitivity Analysis on Separation Costs (±50%)