Analysis of Additional Funding Across the Green Hydrogen Value Chain

August - September 2023

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Contents

Executive summary

The Ministry of Economic Affairs and Climate policy (EZK) is currently working on revising a hydrogen related funding tender (electrolysis targeted aid scheme), focusing mainly on scaling up renewable hydrogen production. The lowest requested cost reimbursement/subsidy for hydrogen production is likely to be the main evaluation criteria.

GroenvermogenNL (GVNL) asked Mott MacDonald (MM) to conduct current study, focussing on mapping the additional components and their associated CAPEX figures (when possible) along the full green hydrogen value chain, which are considered for future value chain scale-up developments. The additional components are those that would be unlikely to be covered in projects participating in a funding tender with the main evaluation criterion as the lowest subsidy for renewable hydrogen production. To do so MM has conducted several interviews with parties involved, or willing to be involved in the green hydrogen value chain and especially in the sectors: Chemistry, SAF, Steel and Fertiliser industries. The list of interviewees was previously agreed with GVNL, and consists of following parties:

- Air Liquide
- BP
- DOW
- HyCC
- Neste
- Nobian
- OCI
- Powall
- Shell
- SkyNRG
- Tata
- VDL

MM was informed that the Dutch Government intends to come up with two types of green hydrogen related funding schemes in the future: **Approach A** and **Approach B**. Under Approach A all elements associated with green hydrogen production are considered, consisting of at least: Electrolyser, essential BOP, water supply, electricity supply and control (also presented in Table 1). The Dutch Government, under control of EZK, intends to fund €1,0bn to projects under Approach A. Approach B consists of all components under Approach A plus any additional components in the green hydrogen value chain. It is proposed GVNL will provide the funding under Approach B, with an approximate amount of €200M - €300M.

Table 1: Cost categories under Approach A.

	Approach A
In-Fence Power Systems	YES
Desalination	YES
Water Treatment	YES
BOP Systems	YES
Electrolyser systems	YES
Compressor Systems[1]	YES
Metering	YES

Based on the outcomes of the interviews the cost to produce green hydrogen is estimated at around ~€5-€10/kg of H_2 in the Dutch market. Assumed is that the ranking criterium for the support scheme will be based on least support per kg of green H_2, hence, supporting the difference

[1] Compressor systems in the hydrogen production facility are only considered to bring the hydrogen to a desired compression level to feed into a backbone system. Additional compression (e.g., hydrogen to be used in automotive at approx. 300bar) is not considered in this process element step.

between grey and green hydrogen. Taking ~€ 2/kg for grey hydrogen would result in a funding ask of ~€3-8/kg under Approach A – only related to the production of hydrogen. Given the total available funding of €1.0bn, which will be available for a period of 10 years, implying an €100M annual subsidy. This budget would enable the production of ~10 - 43 kton per year, with an electrolyser capacity of 250MW-900MW (assuming 2,000 hours of operation per year).

From the interviews it is explicitly noted that especial attention is asked for the funding scheme. When additional funding is offered for "value chain integration", a clear description of the base case assets for green hydrogen production is required. This to ensure that investments for assets are allocated to the appropriate cost category. A base case asset for green hydrogen production would consist of at least: Electrolyser with essential BOP, water and electricity supply and control. Within this study this is considered as Approach A as per Table 1.

The components covered within **approach A (proposed tender selection criteria)** must ultimately be decided by The Ministry of Economic Affairs and Climate Policy. However, based on our findings, Table 1 illustrates the key elements required in hydrogen production that should be included in approach A. Any additional components can be considered as separate from the necessary components for green hydrogen production and should be considered under **approach B (the full value chain)**, which covers all elements within Approach A plus any additional components necessary in the green hydrogen value chain.

There were three major cost categories that were mentioned throughout the interviews:

1. Production
2. Transport and storage
3. Offtaker applications

Within these cost categories, additional components will have costs allocated to subcategories:

- Non-Recurring Engineering Costs
- CAPEX investment for the component
- Installation costs
- Operational costs (OPEX)

We have been informed that over the next 2-3 years, €200-€300 million of budget will be made available to be put towards funding additional components in the green hydrogen value chain **(approach B).** Cost estimates, when available, are provided for the cost categories, and for components within these categories. It is understood that requests for this additional CAPEX funding can be made after the project has been selected for funding under Approach A.

Taking the 250MW to 900MW electrolyser capacity into account the following additional funding requests could be foreseen for the different cost categories:

- Transport & Storage: Additional CAPEX foreseen for the following elements under Approach B, numbers presented are total CAPEX figures.
  - Pressurised Hydrogen Tank: €15M to €70M
  - Liquid Hydrogen Tank: €5M to €45M
  - Liquification/gasification: €120M to €145M
  - Transport trailers (Tube trailers): €27M to €38M
  - Compression systems: €10M to €45M
  - Backbone/Pipeline development: €30M to €90M
- Offtaker Application: Additional CAPEX foreseen for the following elements under Approach B, numbers presented are total CAPEX figures**.**

- Batteries[2]: €300k to €600k
- Low NOx burners: €1M to €17M

It is expected that the funding for these additional costs will be on a CAPEX basis, and hence will not be directly correlated to the kg of H_2 production, but more on the installed MW capacity. Therefore, this study therefore only focusses on the CAPEX investments, all other cost data available for the categories will also be provided.

Two separate workshops were scheduled to further detail the potential CAPEX requirements to enable the further development of the funding scheme. These results have been incorporated into Table 3

Figure 1 specifies the different elements in the (green) hydrogen value chain and the associated funding schemes (Approach A or Approach B) which are related to the specific elements. For some elements within the value chain no funding is available under Approach A or Approach B however, there might be subsequent funding schemes which are applicable to those elements.

The necessity of broadening the focus of the funding from the lowest renewable hydrogen production subsidy to the full value chain (refer to Figure 1 for explanation of the green hydrogen value chain) of renewable hydrogen was emphasised throughout the interview process. The subsidy would need to go beyond the lowest requested cost per kg of renewable hydrogen production in order to help the market to embrace renewable hydrogen, which is difficult at the current cost. Without market demand, the industry would remain reliant on subsidies in the long term.

The most frequently mentioned element to be investigated is the intermittent supply of renewable feedstock not matching with the final users' supply continuity needs. This topic could be addressed by funding to develop a reliable buffer system consisting of, but not limited to, electric storage, backbone, pipelines and hydrogen storage of different sizes and forms. An additional consideration here is the timing of the availability of the Hydrogen backbone in The Netherlands. When the Hystock H_2 storage facility is fully operational and integrated, the backbone can provide significant flexibility for all connected production facilities and offtakers. This could result in any decentralised storage facilities to become redundant.

Another point of attention shared by a number of interviewees is the need to fund high power electrolyser (>1 MW) integrated test facilities to develop innovative technologies valuable for the scale-up. This component would risk being neglected if fundings were based mainly on the proposed hydrogen production subsidy evaluation criteria.

It is important to highlight the economic impact of the adaption of the existing assets based on traditional technologies (such as grey hydrogen, Steam Methane Reformer (SMR) systems) to renewable hydrogen, also considering their intrinsic operating flexibility constraints.

[2] Batteries to allow electrolysers operating in continuity are foreseen to be integrated in the power supply chain rather than in the green hydrogen supply chain.

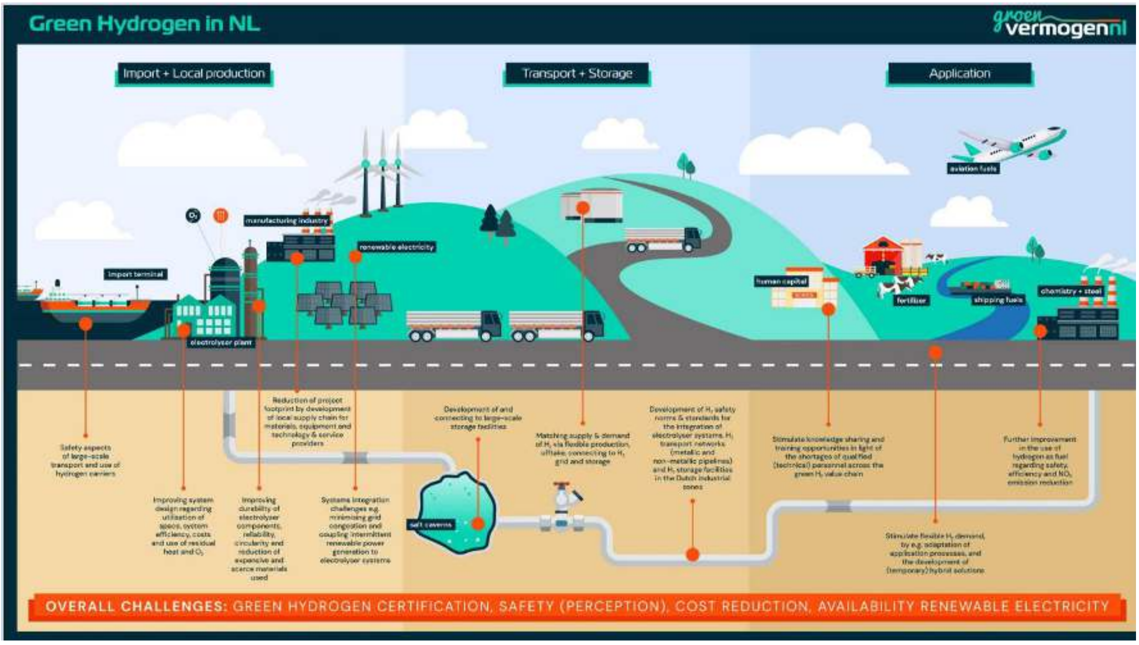


Figure 1: The green Hydrogen value chain

1 Methodology

To provide EZK and GVNL with the perspectives of the stakeholders, the following activities were carried out:

- A semi-scripted interview storyline has been developed and discussed with GVNL.
- Selected stakeholders have been interviewed. Due to practical constraints, a very short period (5 weeks) to execute the project and the timing, during the summer holidays, the stakeholders were “pre-selected” by GVNL based on confirmed availability and interest to participate.
- The input from stakeholders has been consolidated and checked on engineering principles by Mott MacDonald.
- Cost data for the key value chain components have been provided by Mott MacDonald.
- Execution of two workshop with participants from the interview rounds to verify the results presented in the cost table.

1.1 Anonymity of interview results

To maintain the relative anonymity of our interview findings, the content of the report is aggregated, the outcome of the interviews or specific answers of the interviewees cannot be linked to any particular company. The interviewees have supplied information which goes beyond the scope of their specific industry, and thus the information detailed within the industry-specific sections in Section 3.1.3 of the report has come from a wide range of sources.

For confidentiality and competition purposes all cost data has been provided by Mott MacDonald in house experts. The industry, and therefore costs/prices are subject to constant changes, due to factors such as, but not limited to market pressure, inflation and supply of feedstock. Resultingly, it is imperative to note that all costs given will be best estimates accurate as of August 2023. During two workshops on 20 September 2023 these cost figures were cross checked with participants in the interviews.

details the interview questions. The questions were finetuned after three interviews into the process to make them clearer. Nevertheless, the message and meaning of the questions has remained consistent from the first interview to the last.

As set out in question 4 of the questions two main approaches (A and B) are currently considered in the subsidy scheme.

Table 2: The eight central questions used during the interviews

N°	Questions
1	*The Ministry of Economic Affairs and Climate policy (EZK) is currently working on revising a hydrogen related fundings tender (electrolysis targeted aid scheme), focusing mainly on scaling up renewable hydrogen production. The lowest requested cost reimbursement/subsidy for hydrogen production probably will be the main evaluation criteria. What do you think about this selection criteria? Please elaborate.*
2	*What would be the benefit in broadening the focus of the funding to the full value chain of renewable hydrogen?*
3	*Taking into account a sector and assuming existing assets basing on traditional technology (i.e.., grey hydrogen technologies, etc), which are the modifications forecasted to adapt them to apply renewable hydrogen project? And which are the costs associated? And who is in charge of doing this?*
4	*Could you tell us about how you would approach the two following tenders based on two different approaches (A and B below) supporting the answer with an explanation and examples from the start to the end of the value chain (covering as many sectors as are applicable to you)?* *A. Project tailored for renewable hydrogen production focused tender (baseline)à one main evaluation criteria: lowest requested subsidy for produced hydrogen.* *B. Project tailored for renewable hydrogen full value chain (baseline plus increased subsidy for innovation across the value chain) including all those components (assuming additional subsidy for them) that you think valuable and that would be eliminated for approach 4A project.*
5	*Regarding question 4, could you go into more detail regarding the valuable additional components/innovation that would be included in approach 4B projects?*
6	*Is it possible to have an estimation of the cost range (if possible also in €/kgH2 and LCOH impact) for the baseline project, plus the costs for each valuable additional component/innovation forecasted for project 4B.* *Please, support the answer with examples of where in the value chain these costs would arise as well as their nature.*
7	*About the valuable additional components included in full value chain project (B in question 4), which are the components/innovations that should be funded to continue to learn to safeguard innovation when scaled up?*
8	*Are there any other topics to be treated or highlighted that you want to review that could be beneficial for the scope?*

1.2 Workshops

On 13 September 2023 two workshop rounds were organised amongst participants in the interview rounds to verify the results of the current study. The main objective of this session was to verify whether the cost figures presented and the associated allocation of funding scheme was correct. The results of this workshop have been incorporated into this current report.

2 Feedback on proposed tender selection criteria (Approach A)

The current section presents the main feedback provided by the interviewees on the proposed tender selection criteria, or Approach A.

2.1 Inefficiencies and market price

A point raised by many interviewees was that **approach A** based on the lowest requested subsidy could work in theory. It would be the least complex selection criterium and would make the tender "clean and clear". It would be an easier comparative measure than additional innovation, as hydrogen production cost can be objectively measured and directly compared. It was also suggested that hydrogen production and application should be evaluated separately.

However, the overarching opinion was that the proposed tender selection criteria **(approach A)** would work only if the goal was to scale up hydrogen production in isolation. The necessity of broadening the focus of funding to the full value chain of renewable hydrogen was emphasised throughout the interview process. It was stated that by only subsidising or facilitating the production (or indeed any singular part of the value chain), there will be parts of the value chain that will be uneconomic.

Example: If green hydrogen production is subsidised, the overall costs for green hydrogen might remain too high for a consumer. Then there will be no market for products produced with green hydrogen. If companies land at a certain cost of hydrogen, the average offtaker of hydrogen probably will not be able to absorb it. It is imperative that there is no dissonance between what the hydrogen producer is able to produce per cost price versus what the offtaker is willing to pay. The subsidy would need to go beyond production in order to help the market to embrace hydrogen, which is difficult at the current cost. Without market demand, the industry would remain reliant on subsidies in the long term. The market needs to be able to absorb the additional cost or demand will stall in the end.

In order to develop and scale up the renewable hydrogen value chain, it is key to look at which parts of the full value chain are uneconomic and identify the bottlenecks, incentivising across the entire value chain to bring lower costs across the board. The most frequently mentioned uneconomic element was the intermittent supply of renewable feedstock, which will be discussed in more detail in subsequent sections of the report.

2.2 Benefits across value chains

By the interviewees it was widely mentioned that the proposed selection criteria will only stimulate certain value chains that are already open to implementation and where the market has the highest ability to pay. It therefore does not encourage innovation.

Example: goods such as biofuels where market demand is already supported through the EU's Renewable Energy Directive and the sale of fuels such as E10 and E15.

Example: value chains that would be at an advantage is those which have greater flexibility in their production processes. Processes that involve large refineries such as in the chemical industry where it is unsafe or highly inefficient to flex production would have to establish entirely new processes at large cost.

Without the help of subsidies, a number of value chains would have to wait until the cost of hydrogen goes down. To ensure decarbonisation across sectors, a consideration of the full value chain is required.

Another point of view raised, is that within larger industries the additional subsidies should not be viewed as a solution to the entirety of the renewable hydrogen supply problem, but rather as steppingstones for learning throughout the industry. It is important to focus on innovative projects that could work towards finding a solution in reducing the cost for LCOH in the long run, by investing in technology along the value chain. In the long-term, development should be across the full value chain as all interactions with the market lead to cost increase.

Another aspect to consider is that of safety. It has been argued that having low cost as the main driver may lead to sectors or companies opting for less safe solutions.

The consensus across the interviews was that a tender that based its evaluation criteria across the entire renewable hydrogen value chain was more likely to stimulate innovation. With smaller subsidies that only cover hydrogen production, companies are more likely to make risk averse decisions.

An integral approach from manufacturing, to instalment, to production is key. A lot of subsidies are currently going to end users who buy equipment that is already existing due to the lower risk factor, even if they are not necessarily the most economic or efficient solutions. New and innovative solutions are considered higher risk and are overlooked, even if the technology is more efficient and economical compared to the more experienced players.

3 Cost Figures

This section presents the main cost drivers within the hydrogen value chain as per the main categories in this study:

- Hydrogen Production
- Transport & Storage
- Offtaker Application

This information is presented in Section 3.1, the cost figures provided are in principle CAPEX figures, if different figures are presented this is explicitly stated.

Separate to these main cost drivers the interviewees stated that several additional support, different than CAPEX support, is needed to accelerate the development of the green hydrogen value chain. These cost drivers are not part of the costs within the green hydrogen value chain.

3.1 Cost Figures Hydrogen Value chain

Table 3 presents the cost drivers for the hydrogen value chain amongst the categories:

- Hydrogen Production
- Transport & Storage
- Offtaker applications

In the subsequent Sections more explanation on the figures presented in Table 3 is provided.

In the table is reflected whether the cost item should be in Approach A, B or no funding should be made available via either Approach A or B (funding can be made available via alternative funding schemes). The results of items presented in the cost table are verified during two workshops on 13 September 2023.

Table 3: Cost drivers for the hydrogen value chain

#	Item	Scheme	Estimated Cost	Comments
			Hydrogen Production	
1	High Voltage Connections	Approach A	CAPEX: 110 and 150 kV approx. €1.5M 220 and 380 kV approx. €3.0M	Only CAPEX figures, grid tariffs are to be paid on annual basis additionally (OPEX). OPEX Figures are dependent highly on project specific characteristics. For a 1GW plant these are estimated between €10M – €35M per year
2	In-Fence Power Systems	Approach A	CAPEX: Alkaline system: €150-250k per MW Capacity PEM system: €200-300k per MW Capacity	Figures presented are for plant size from 50-100MW capacity. For larger facilities (>2GW) costs are reduced by roughly 25%.
3	Desalination Systems	Approach A	CAPEX: €2.5 – € 7.5 / MW electrolyser capacity	
4	PEM Electrolysers	Approach A	CAPEX: 50-100MW facilities: € 1.250.000 - €1.600.000 per MW capacity GW scale facility: €650.000 - € 950.000 per MW capacity	Including BOP facilities

#	Item	Scheme	Estimated Cost	Comments
5	Alkaline Electrolysers	Approach A	CAPEX 50-100MW facilities: € 1.000.000 - €1.300.000 per MW capacity GW scale facility: €500.000 - € 800.000 per MW capacity	Including BOP facilities
		Transport & Storage		
6	Hydrogen tank vs scale-up	Approach B	CAPEX: €15.0M to €20.0M	Small scale pressurised hydrogen storage tank on site (28,000kg capacity)
7	Hydrogen liquid tank vs scale-up	Approach B	CAPEX: €150 to €400 per kg liquid Hydrogen	Only Liquid Hydrogen storage tank
8	Liquefaction/gasification chain development vs scale-up	Approach B	CAPEX: €120M – €150M	Liquefier CAPEX with capacity of 30T
9	Transport trailers (Tube Trailer)	Approach B	CAPEX: €600k – €900k	Tube trailer capacity approx. 600kg H_2
10	Filling Centre	Approach B	CAPEX: €20M to €30M	Filling centre CAPEX with capacity of 10T
11	Conditioning and purification of hydrogen vs. scale-up	Approach B	N/A	No cost data available Postproduction purification likely not required
12	Compression systems vs scale-up	Approach B	CAPEX: €0.9M to €1.3M per MW compression capacity	Highly dependent on compression approach (e.g., atm to 50 bar or 15 bar to 50 bar) and specific plant capacity
13	Salt cavern-based stock development[3]	No Funding	Additional increase of LCOH of €0.07 to €0.47 per kg hydrogen	Additional costs for storing hydrogen in salt caverns..
14	Backbone/ Pipeline development	Approach B	CAPEX: €1.5M –€3.5M per km	Highly dependent on site characteristics, method of construction and pipe characteristics.
15	Boil-off Reduction (Liquid Hydrogen)	No Funding	In a 30T system boil-off cost are between €12k and €30k per dispense	Rough estimation of boil-off is about 10% (each time the hydrogen is dispensed)
16	Hydrogen Carriers (example: ammonia)	No Funding	€650 to €1300/T ammonia[4]	Production costs for green ammonia using green hydrogen as feedstock
		Offtaker Applications		

[3] Salt caverns are developed by the Hydrogen Network Operator and will not be taken into account in further cost breakdown.

[4] Hydrogen carriers such as ammonia will need an entire value chain on itself but are also part of the green hydrogen value chain. Cost figures presented are only indicative. These carriers are not further considered in cost breakdown.

#	Item	Scheme	Estimated Cost	Comments
17	Batteries to allow electrolysers operating in continuity	Approach B	CAPEX: €300k – 600k per MWh installed capacity	For Battery Energy Storage System Batteries only considered on the front end to control ramp rate control.
18	Low NOx burner	Approach B	CAPEX: for converting heat production equipment (including and not limited to burner) from methane to hydrogen: €400k – 1M for 10MW	Indicative overall estimation for offtakers applications
19	General - Grey hydrogen producing assets impact: Minor SMR capacity reduction	Approach B	N/A	From rough estimation, grey hydrogen existing assets (example SMR) can still work after applying modifications if their capacity reduction is minor due to replacement with green hydrogen. Costs to be estimated for each business case.
20	General - Grey hydrogen producing assets impact: Major SMR capacity reduction	Approach B	N/A	From rough estimation, grey hydrogen existing assets (example SMR) cannot operate anymore if their capacity reduction is major due to replacement with green hydrogen. Costs to be estimated for each business case.
21	General - Grey hydrogen producing assets impact: loss of production	No Funding	N/A	No cost data available, different for each business case. dependent on actual loss of production and remaining planned operational lifetime installation. Loss of production is considered as not being included in any funding.
22	General - Adapting to green hydrogen: final application process impact. Costs for training, increased operations, recruitment of additional staff, eventual automation and certification	Approach B	N/A	No cost data available, different for each business case.
23	Steel - process/plant impact of renewable hydrogen uses for decarbonisation (i.e., DRI)	No Funding	N/A	Components necessary to transform a conventional steel production plant into a green steel production plant not considered. Cost for any hydrogen related equipment on site are to be considered.

#	Item	Scheme	Estimated Cost	Comments
24	Chemical Heat integration and waste heat optimization	No Funding	LCOHeat €10 to €20 per GJ	Feasibility highly dependent on capacity electrolyser, availability of district heating network and distance to possible offtakers.
25	SAF – innovative process for eSAF production	No Funding	Cost for eSAF are approx. 5 to 10 times higher than traditional aviation fuel.	Components necessary to transform a conventional steel production plant into a green steel production plant not considered. Cost for any hydrogen related equipment on site are to be considered.

The baseline costs under **(Approach A)** are likely to cover the costs for green hydrogen production. No new elements have been investigated which could be covered under **Approach B.** However, it must be stated that additional funding might be required under **Approach B** which initially fall under **Approach A.** Examples are additional high voltage connections or additional electrolysis capacity.

The different elements specified in Table 3 which relate to the (green) hydrogen value chain is also illustrated in Figure 2. This figure specifies the specific elements in the value chain and what funding scheme is applicable to the specific element (Approach A or Approach B). For some of the elements no funding is available under Approach A or B however, funding might be available under alternative funding schemes.

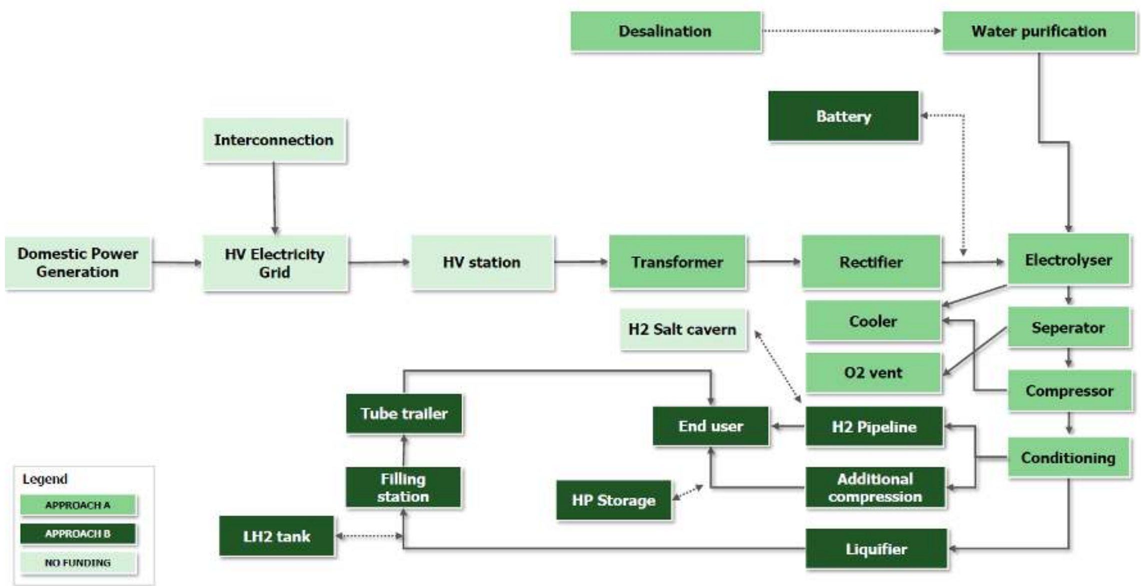


Figure 2: Hydrogen value chain specifying the different elements and associated funding schemes

3.1.1 Hydrogen Production

There are no additional cost figures identified which are considered to be funded under Approach B whilst not being supported under Approach A. The interviewees stated that the components related to the hydrogen production facility are all considered to be supported under Approach A.

3.1.2 Transport & Storage

Several cost categories relate to the Transport & Storage elements. These elements are considered to be used to balance output of the electrolyser production facility into a continuous flow of hydrogen towards the offtaker applications. The sections below detail the different cost items listed under this element.

Lines 6 to 17 of Table 3, relate to the Transport & Storage elements If, for example, we were to consider an example of the proposed tender selection criteria where production is subsidised and an electrolyser is purchased, although there would be green hydrogen produced, a reliable supply is highly improbable. A constant throughout the interview process was the problem of supply intermittency. This would create a number of production inefficiencies which will be explored later within the report. It is uneconomical to run plants with variable flows of hydrogen, they must operate at very close to 100% utilisation to remain competitive.

Example for energy storage in northern Europe: Assuming renewable energy production only (75% wind and 25% solar), and a generic operating plant operating load range of 80-100%, two days of storage would be required.

This topic could be addressed by funding and developing a reliable buffer system consisting of, but not limited to, electric storage, backbone, pipelines (Refer to line 15 of Table 3) and hydrogen storage of different sizes and forms

Ammonia cracking/conversion development/innovation are other potential buffering methods mentioned that funding could go towards (Refer to line 17 of Table 3).

In terms of buffers, salt caverns were repeatedly mentioned as one of the quickest and simplest high volume storage solutions (Refer to line 13 of Table 3)

For low volume storage, it was highlighted the need to invest in the scale-up compressed hydrogen tanks (Refer to line 6 of Table 3). Explained in more detail below, liquid hydrogen storage is another potential solution to intermittency issues (Refer to line 7 of Table 3).

Subsidies would be required for scaling up the listed buffering methods. It would likely be done incrementally, starting at a €10 million scale, then €100 million, then close to €1 billion for the final scale up (Refer to line 14 of Table 3).

Converting natural gas pipelines to hydrogen pipelines is another area that subsidies could help.

3.1.2.1 Gaseous Filing Centres (Refer to line 10 of Table 3)

One method of including those users within the sixth cluster (i.e., not served directly by pipelines, at least in the first phases) would be building gaseous filling centres. The first stage would be to take the gaseous hydrogen molecule from the plant to the filling centre. Technologies at the relevant pressure level already exist, but a decision must be made in terms of the most suitable containers in terms of size and materials. The gas would then need to be compressed into tube trailers made of steel or reinforced steel and transported to the filling centre.

Currently no gaseous filling centres large enough to cope with anticipated supply exist, therefore the next step would be to construct filling centres large enough to deal with future scale-ups in the gaseous supply chain output. Elements of innovation and collaboration with suppliers to select the right components would be required in terms optimising energy usage in the plant by ensuring the correct handling of the pressures and flows that would exist on a larger scale. These filling centres could, for example, fill trucks to supply hydrogen refuelling stations (HRS). For customers needing larger volumes, (more than 3T or 4T a day of hydrogen), 5-8 lorry movements per day to site would be needed (Refer to line 9 of Table 3). Given this amount of lorry movements per day, this approach will be challenging.

3.1.2.2 Liquefaction and regasification (Refer to line 7 of Table 3)

The above approach of using gaseous filling centres could be argued as being logistically vulnerable so liquid hydrogen may be the preferred solution for storage and transport. The focus of the innovation should be on liquefaction units. The technology already exists, the largest hurdle, however, would be scaling up to liquid hydrogen from 30T to 100T per day, taking advantage of economies of scale for a lower LCOH. There are several technical challenges the industry faces in allowing a plant to reliably produce at this capacity. There are certain components and materials that do not yet exist and therefore investment in innovation is required. Regasifying the liquid hydrogen would also be required and would mean onsite storage needed at the customer's location.

A key element to mention is the need for innovation to reduce the boil off rate of hydrogen, which currently sits at around 10% each time the hydrogen is dispensed from one container to another (Refer to line 16 of Table 3).

For comparison purposes (the below costs have come directly from the interviews and have not been verified):

- The liquefier (refer to line 8 of Table 3) will have a likely impact on the supply chain costs of 120-150M € CAPEX for a 30T system. Which will have large influence on LCOH given the amount of hydrogen which can be liquified. Liquefiers of 100T+ will reduce the impact on LCOH but are not ready for market at this moment.
- The gaseous filling centre (Refer to line 10 of Table 3) would have a likely impact on LCOH of +1.5-2 euro per kg of hydrogen.

3.1.2.3 Purification and Conditioning (Refer to line 11 of Table 3)

A certain level of purification and conditioning of the hydrogen would likely be required within many transport and storage processes.

3.1.2.4 Compression (Refer to line 12 of Table 3)

Innovation in the field of compression equipment should be funded in order to pressurise hydrogen more economically for storage. As mentioned in the previous section, if the government were to fund test facilities (line 1 in Table 4) that could, for example, test scaling up from a 10MW scale to a 100MW scale the risk would be reduced.

3.1.2.5 Economies of Scale

Economies of scale are essential to ensure the LCOH to go down in the long term. The larger the market for renewable hydrogen the more a certain portion of the fixed costs are shared., however ensuring there will be an initial market that is able to pay for high volumes means that the power price needs to be competitive.

Baseline production (**approach A**) is likely to cover only the production of hydrogen (refer to Table 1) including part of the compression step (refer to line 12 of Table 3). For the Transport and storage category under **approach B,** all additional compression for transport & storage applications is considered above the initial compression under **Approach A**.

3.1.3 Application

The sections below present more insight into the cost elements related to offtaker applications.

3.1.3.1 General offtakers

Although the scope of the interviews covered four main sectors (chemicals, SAF, fertiliser and steel), there were many comments made that fell into a more general category that could apply to each of the sectors as well as others not mentioned.

Subsidies will be required to make products produced using green hydrogen economically competitive with grey hydrogen products. In the case of end users using natural gas, it is forecasted to be more expensive to switch to green hydrogen than starting from grey hydrogen. Subsidies will be required to offset the costs of expensive process changes as well as the increased product prices. In processes where a lot of hydrogen is used, and margins are slim, the effect is large. In other processes, the effect might not be as significant.

A general statement from the interviewees regarding the comparison between **approach A** and **approach B** is that it's more likely that, once the subsidy is removed, **approach B** will be able to stand on its own since the full renewable hydrogen value chain will be developed (including renewable energy plants, electric network, electrolysers, hydrogen purification system, hydrogen backbone, etc) (Refer to line 15 of Table 3). This would in turn avoid the occurrence of bottle necks that would be more likely to occur in **approach A** focussing solely on the production step of the value chain.

All end users that use industrial burners e.g., steel, chemical, refineries etc would benefit from the additional subsidies/fundings that could be available in **approach B** for developing hydrogen specific burners, also addressing NOx emissions issues (Refer to line 19 of Table 3).

3.1.3.2 Fertiliser

Many interviewees raised the point that, in order for locally produced green fertiliser to remain competitive, the industry would benefit from regulation mentioned in the Appendix's Local Production and Imports section, that ensures imports do not have an economic advantage.

The current nitrogen-based fertiliser production process involves the creation of ammonia from grey hydrogen. As a result, the specific fertiliser production process could be switched in a relatively easy way from grey to green hydrogen, as hydrogen is already used in the production process as feedstock.

It was also pointed out that, as with other industry sectors, fertiliser plants need continuous hydrogen supply. The intrinsic variability of renewable hydrogen needs to be compensated with a buffer system, otherwise plants would face intermittencies, lowering their competitiveness in the market (Refer to line 14 of Table 3). Considering the global fertiliser market, green hydrogen in the Netherlands must remain competitive. The final user of fertiliser, i.e., farmers, would be focussing solely on the most efficient input of nitrogen-based fertiliser.

As is the same. This could be mitigated with off-takers subsidies to incentivise the purchase there is currently no regulatory requirement to encourage the purchase of fertiliser produced with green hydrogen, it is foreseen that the market will continue to purchase fertiliser with the lowest cost price. Which is currently nitrogen fertiliser produced with grey hydrogen.

Example: Modification of existing assets is needed to adapt them to use green hydrogen as feedstock (Refer to line 23 of Table 3).

Assuming a nitrogen-based fertiliser plant is currently using grey hydrogen as feedstock and that hydrogen is produced by means of an SMR system, the main existing asset impacted by the switch from grey hydrogen to green hydrogen is the SMR system. The impact would be different based on two different cases:

1. *Renewable hydrogen feed minor percentage of SMR capacity (Refer to line 20 of* Table 3*)* → *relatively small modifications to the original assets, including a small air separator for nitrogen or nitrogen from over the fence. Modified SMR and electrolyser systems could provide the requested hydrogen in combination with grey hydrogen. Based on the required investments), this case could be representative of a project that could participate in the* ***approach A*** *tender.*
2. *Renewable hydrogen feed major percentage of SMR capacity (Refer to line 21 of* Table 3*)* → *The SMR system cannot run below a certain load. In this case, the SMR couldn't be used anymore and should be replaced totally by an electrolyser system or other systems such as the ones needed for nitrogen supply (i.e., over the fence or air separator, etc…). The investments needed for this case is much higher than the previous case, also including downtime (Refer to line 22 of Table 3)during the construction of new assets and possibly the intermittency impact on plant operations. Based on the needed investments, this case could be representative of a project that could participate in a tender in* ***approach B.***

3.1.3.3 Sustainable Aviation Fuels

The sustainable aviation fuel (SAF) sector is a considerable end user of hydrogen. Hydrogen can be used in different processes for the production of SAFs, from the hydrogenation of oils (requiring smaller volumes of hydrogen) to feedstock for the synthesis process to create eSAF (requiring larger volumes of hydrogen).

The production of SAF needs to have continuity and stability in the hydrogen supply. Therefore, given the variability of renewable energy sources, a robust buffer system (Refer to line 14 of Table 3) is needed to meet continuity requirements.

It was highlighted that existing SAF plants using already grey hydrogen do not require lot of modification. Some downtime would be required, and certain assets would be made redundant (Refer to line 22 of Table 3). Adapting them to green hydrogen could potentially consist of switching the hydrogen intake from grey to green, probably partially keeping the intake of grey hydrogen to compensate possible variability of green hydrogen/lack of buffer. However:

- Hydrogen conditioning and purity requirements need to be taken into account in the investments (Refer to line 11 of Table 3).
- The cost difference between grey and green hydrogen must be taken into account to develop renewable hydrogen SAF off-takers demand. **Approach A,** focussing mainly on renewable hydrogen production, would not cover offtaker related subsidies.

During the interview process, it was mentioned that **approach B**, based on additional funding, could especially enable eSAF fuels production, which requires the highest investments to adapt to renewable hydrogen due to:

- The highest amounts of hydrogen needed for their synthesis (compared to standard SAF)
- eSAF plants are limited compared to other SAF production plants and therefore require new assets, new projects, and many operative aspects to be considered.

In **approach B**, it was also highlighted that innovative and more efficient processes (Refer to line 26 of Table 3) to produce eSAF could be developed based on funding that covers the end user's step of the renewable hydrogen value chain.

3.1.3.4 Chemistry

The consensus was that **approach A** would be the most straightforward however, it has shortcomings.

It is the preferred approach for large scale projects where the cost of distribution is less of an issue, such as large businesses who could absorb cost of an electrolyser with ease, as well as businesses who are located close to existing pipelines.

As more and more renewable hydrogen is added to production, it starts to affect the requirements of existing assets. It is not possible to run a fossil-based plant without considering that there is a minimum production load. It is also important to highlight the substantial costs of the loss of production (Refer to line 22 of Table 3) with assets that were supposed to be running at 90% loads and are now running at lower loads 60%, i.e., SMR and ATR for grey or blue hydrogen production). It must be highlighted that in this case, the operational parameters need to be changed substantially (Refer to line 21 of Table 3), causing difficulties in terms of respecting operational constraints and requiring investments to adapt to green hydrogen. The additional costs that should be considered are training, increased operations due to widened plant operating ranges, recruitment of additional staff, eventual automation, and certification (Refer to line 23 of Table 3)

Approach B would be a more complex, but fairer approach, that would allow more customers to be tapped into as well as greater innovation opportunities of elements within the whole green hydrogen value chain.

During the interview process, it was highlighted that **approach B** would complete **approach A** and allow additional projects to be included that would not have been covered in approach A. These projects would be the ones with larger subsidy gaps. Approach B enables funding across the entire value chain, based on fully integrated projects which lead to higher funding requirements.

An area of interest that could be very valuable if funded and developed is heat integration and use of waste heat (Refer to line 25 of Table 3).

One of the key elements of the successful adaptation of green hydrogen in the chemical industry (and across all industries to some extent), is the consistent supply of feedstock. The nature of the supply of green hydrogen feedstock is that it is highly variable. Production in the chemical industry is used to running at close to maximum capacity and would therefore need a consistent supply of green hydrogen to maintain the same levels of output as well as the same product quality. It is also important from a safety point of view that the green hydrogen supply is consistent. There are safety risks associated with stopping and starting production of chemicals as a result of inconsistent hydrogen supply. Due to the lack of flexibility within chemical processes it is essential that there are effective systems put in place to mitigate the variable supply situation.

Overall, running a large chemical plant at low output levels would be highly inefficient. In order to cope with this situation, the interview process highlighted three possible ways:

- Implementing buffers (Refer to line 14 of Table 3)
- Changing the chemical process to accept greater variability (this unlikely to be applicable based on general interviewee feedback)
- Dividing production into multiple smaller plants

Example: An example that was mentioned is for a refinery with no local grey hydrogen production i.e., no ATR (Autothermal Reforming) or SMR on site. In this case, currently, the plant produces part of the needed hydrogen as a by-product to their existing processes. The rest of the required hydrogen is bought from other parties. In this case, they aim to use hydrogen for the removal of impurities in the fuel production process. Adapting this application to green hydrogen would mainly consist of the change of feedstock, from grey to green hydrogen.

3.1.3.5 Steel Production

It is important to note that in comparison to certain industries such as the fuel industry, there are currently no mandates or regulations in place for a certain percentage of steel production to come from renewable sources. In order to remain competitive, the industry would require large subsidies to absorb the additional costs.

In terms of repurposing existing assets based on traditional technology, given the current coal-based nature of the steel sector, a 100% switch from coal-based production to renewable hydrogen production would be a significant and costly shift.

The most probable approach is that an alkaline electrolyser would be purchased (Refer to line 5 of Table 3). Alkaline electrolysers are considered the lowest risk electrolyser option however would not be considered an innovative solution.

To introduce the hydrogen (green or grey) into the steel production process, part of the mill would need to be replaced. This would need to be done in a way that works with the existing iron ore process to avoid stopping production for a significant amount of time.

Approach B

Additional subsidies to encourage innovation would be likely to encourage the steel sector to look into investing into more innovative electrolysers such as high pressure or low PGM electrolysers (Refer to lines 2 and 3 in Table 4) rather than going for the lowest risk option.

As mentioned elsewhere in the report, one of the key elements in successfully implementing the use of green hydrogen within any industry is dealing with the problem of intermittency. Due to the high temperatures in steel mills, it is key to avoid too many fluctuations in the supply of renewable hydrogen feedstock. Suggested solutions to this problem include effective pipelines and buffers including buffer tanks on the electrolyser side in order to keep the pressure at the output stable and prevent the system from ramping up and down too often.

Approach B would facilitate a safer approach to installation, with emphasis placed on gas conditioning (Refer to line 11 of Table 3) to ensure optimum purity and temperatures.

This approach would also include investing in engineering research subsidies into different types of electrolysers as well as more efficient integration solutions.

The price of steel would more than double in both **approaches A** and **B** if **approach A** were to include an entire switch from coal to renewable hydrogen. **Approach B**, however, is likely to lead to lower over the long-term the LCOH.

3.2 Additional Cost components

There is a clear difference between sectors which already use (grey) hydrogen in their production processes and sectors which do not use (grey) hydrogen at this moment, the d For companies/industries already using hydrogen as a chemical molecule, the molecule remains unchanged regardless of its origin (grey or green), meaning that the processes involved would have lower costs in terms of integrating green hydrogen into their production, putting them at an economic advantage. The elements which are nominated by the interviewees are all not related to the value chain of green hydrogen but to the additional components as listed in Table 4

Table 4: Additional components necessary to accelerate the green hydrogen value chain

#	Item	Estimated Cost	Comment
1	Integrated test facilities to develop electrolysers vs scale-up (larger than 1 MW)	Rough Estimation: €10M – €50M	No cost data available. Main cost drivers regarding test facilities are currently under evaluation by GVNL separately.
2	Development of innovative electrolysers (example: pressurisation, etc) vs scale-up	N/A	No cost data available. R&D programmes are funded separately.
3	Development of low content rare materials (i.e., PGM, etc) electrolysers vs scale-up	N/A	No cost data available. R&D programmes are funded separately.
4	Integrated test facilities to develop components/systems (related to Transport and Storage) vs scale-up	N/A	No cost data available. Main cost drivers regarding test facilities are currently under evaluation by GVNL separately.
5)	New products development, out of current value chains (example of DMS working on new proteins based on H2	N/A	No Cost data available

3.2.1 Novel electrolyser innovation (Table 4, refer to line No. 2)

From the interviews it was noted that additional innovation subsidies could be spent in production, it would be logical to start with a cost evaluation of the electrolyser system. Based on this cost evaluation producers could set out making an electrolyser that would lead to the LCOH in the long term.

3.2.2 Low PGM electrolysers (Table 4, refer to line No. 3)

It was explicitly noted that for the production of PEM electrolysers (currently constituting of 30% market share in the electrolyser market) iridium is used in large quantities and a critical material. Iridium is a high-cost component, and therefore a focus on the innovation of novel electrolyser materials and technologies that reduce the amount of iridium by up to 60% through novel manufacturing techniques would likely contribute to the long-term reduction of LCOH.

3.2.3 High pressure electrolysers (Table 4, refer to line No. 2)

Hydrogen is produced at a certain pressure and quality. The operational pressure of the electrolyser and eventual additional compression with compressors is key to the final cost of the hydrogen (LCOH). To feed into the hydrogen backbone the hydrogen pressure needs to be between 30 and 70 bar. By investing in the innovation of electrolysers capable of producing hydrogen at highest pressure possible (compatibly with technical cost constraints), it would reduce cost of compression further down the value chain.

Example: to pressurise hydrogen to 70 bar from a starting point of 10 bar would require significantly less energy consumption than if you were to start with an electrolyser that produced hydrogen at the pressure of 1 bar. This is an area where the government should step in to subsidise new technologies to give them a chance and encourage end customers to work with new innovative companies to test new equipment, firstly on small scale, then to scale up quickly afterwards. Large companies should be encouraged to use this new innovative equipment.

Increasing the operating pressure of electrolysers lead to a decrease of necessary compression further in the value chain. However, the cost for electrolysers operating at higher pressure are typically higher to those running at lower operating pressures. From full value chain point of view, It is important to understand the pressurization level up to which it is still economically advantageous to increase the operating pressure of the electrolysers.

3.2.4 Test facility (Table 4, refer to line no. 1)

By the interviewees it is explicitly listed that, to further commercialise the approaches listed under Sections 3.2.1 to 3.2.3, testing facilities are required. These facilities can be used to demonstrate that novel concepts could work at scale. The interview findings show that there is a desire for the government to mitigate at least a certain percentage of the risk involved in innovation, acting as an insurer rather than in a subsidiser capacity. Producing companies are most likely to choose the lowest risk option, thus discouraging innovation.

It has been suggested that the additional subsidies covering the entire renewable hydrogen value chain could go towards the creation of a large-scale common testing facility over 1MW to trial innovative technologies such as electrolysers devices, catalysts and membranes. The same principles could be applied to transport and storage.

Benefits of a testing centre include:

- Acting as a common centre missing link between universities and knowledge centres and the industry at large
- Provision of a sustainable influx of even lower cost green hydrogen capabilities
- De risking commercialisation
- Controlled risk of novel technologies
- Lowering overall cost of production in the longer term
- Containing innovation within the Dutch ecosystem
- Accelerating production and commercialisation of novel technology
- Option for the government, for example to purchase the test hydrogen at reduced rates

4 Conclusions

4.1 General

The necessity of broadening the focus of the funding from the lowest renewable hydrogen production subsidy (**approach A**) to the funding for elements in the full value chain of renewable hydrogen **(approach B)** was emphasised throughout the interview process. The subsidy would need to go beyond production in order to help the market to embrace hydrogen, which is difficult at the current cost. Without market demand, the industry would remain reliant on subsidies in the long-term.

Many interviewees fed back that the lowest renewable hydrogen production subsidy selection criteria would only stimulate certain value chains that are already open to implementation and where the market has the highest ability to pay, and therefore would not encourage innovation. With smaller subsidies that only cover hydrogen production companies are more likely to make risk averse decisions

Another point of view raised is that within larger industries the additional subsidies should not be viewed as a solution to the entirety of the renewable hydrogen supply problem, but rather as steppingstones for learning throughout the industry. It's important to focus on innovative projects that could work towards finding a solution in reducing the cost for LCOH in the long run, by investing in technology along the value chain.

A summary table including the additional components and their estimated costs is available in Table 3.

4.2 Hydrogen Production

Full renewable hydrogen value chain-oriented funding would allow the innovation of electrolyser systems including the development of new technologies such as low PGM electrolysers and high-pressure electrolysers. LCOH would benefit in the long run from this innovation.

In order to commercialise the above innovations, it would be essential to build testing sites in order to demonstrate that novel concepts could work at scale. The interview findings show that there is a desire for the government to mitigate at least a certain percentage of the risk involved in innovation, acting as an insurer rather than in a subsidiser capacity. Producing companies are most likely to choose the lowest risk option, thus discouraging innovation.

It has been suggested that the additional subsidies covering the entire renewable hydrogen value chain could go towards the creation of a large-scale common testing facility up to one megawatt in order to trial innovative technologies such as electrolysers devices, catalysts and membranes. The same principles could be applied to transport and storage.

However, such innovations are not considered in the funding under Approach A or B. No additional elements related to hydrogen production were listed by the interviewees which should be included in approach B.

4.3 Transport & Storage

The most frequently mentioned element to be investigated is the intermittent supply of renewable feedstock not matching with the final users supply continuity needs. This topic could be addressed by funding and developing a reliable buffer system composed by, but not limited to, electric storage, backbone, pipelines and hydrogen storages of different sizes and forms.

It was suggested the additional value chain subsidy could be spent on batteries to store electricity downstream of the renewable energy sources in order to compensate their variability and reduce the variability of electrolysers as much as possible (minimum base load is a constraint). It's important to note that background for this suggestion is compliance with EU regulations. The additional funding could also be used to invest in development of new and more efficient batteries.

In terms of buffers, salt caverns were repeatedly mentioned as one of the quickest and simplest high volume storage solutions. However, salt caverns are developed outside of the scope of subsidy Approach A or B.

The above approach of using gaseous filling centres could be argued as being logistically vulnerable so liquid hydrogen may be the preferred solution for storage and transport. The focus of the innovation should be on liquefaction units.

A key element to mention is the need for innovation to reduce the boil off rate of hydrogen (i.e., involving liquefaction), which currently sits at around 10% each time hydrogen is dispensed from one container to another.

Innovation in the field of compression equipment should be funded in order to pressurise hydrogen more economically for storage.

4.4 Offtaker applications

steel, there were many comments made that fell into a more general category that could apply to each of the sectors, as well as others not mentioned.

As mentioned above, when we consider end users who already use grey hydrogen within their processes, in terms of production it would be simple to replace existing grey hydrogen with green hydrogen as it is the same molecule. However, subsidies will be required to reduce the cost of green hydrogen products to that of grey hydrogen products in order to maintain demand.

A general statement from the interviewees regarding the comparison between approach A vs approach B is that it's more likely that once the subsidy is removed, approach B will be able to stand on its own feet since the renewable hydrogen full chain will be developed (including renewable energy plants, electric network, electrolysers, hydrogen purification system, hydrogen backbone, etc). This would in turn avoid the occurrence bottle necks that would be more likely to occur in approach A which focusses solely on the production step of the value chain.

All end users that use industrial burners e.g., steel, chemical, refineries etc would benefit from the additional subsidies/fundings that could be available in approach B for developing hydrogen specific burners, also addressing NOx emissions issues.

It has to be highlighted the economic impact of the adaption of the existing assets basing on traditional technologies (such as grey hydrogen SMR systems) to renewable hydrogen, also considering their intrinsic operating flexibility constraints.

Fertiliser sector - It was also pointed out that, as with other industry sectors, fertiliser plants need continuous hydrogen supply. The intrinsic variability of renewable hydrogen needs to be compensated with a buffer system, otherwise plants would face intermittencies, lowering their competitiveness in the market (this is especially valid in case it is assumed the full supply is green hydrogen). Considering that the fertiliser market is global, Dutch renewable hydrogen needs to remain competitive. The final user of fertiliser i.e., famers, would be focussing solely on the most efficient input of nitrogen-based fertiliser.

SAF sector - The sustainable aviation fuel sector is a considerable end user of hydrogen. It can be used in different processes for various SAFs, from the hydrogenation of oils (requiring smaller volumes of hydrogen) to feedstock for the synthesis process to create eSAF. Much like the other large hydrogen users from other sectors the need to have continuity and stability in the hydrogen supply has been highlighted. Therefore, given the variability of renewable energy sources, a robust buffer system is needed to meet continuity requirements (this is especially valid in the case where the full supply is assumed to be green hydrogen).

Chemistry sector- During the interview process, it was highlighted that approach B would complete approach A and allow additional projects to be included that wouldn't have been covered in A. These projects would be the ones with larger subsidy gaps. Approach B enables across value chain, basing on fully integrated projects which lead to higher funding requirements. An area of interest that could be very valuable to be funded and developed is the heat integration and use of waste heat. One of the key elements of successful green hydrogen production in the chemical industry (and across all industries to a smaller or larger extent), is the consistent supply of feedstock. Production in the chemical industry is used to running flat out and would therefore need a consistent supply of green hydrogen to maintain the same levels of output. It is also important from a safety point of view that the green hydrogen supply is consistent. There are safety risks associated with stopping and starting production of chemicals as a result of inconsistent hydrogen supply. Due to the lack of flexibility within chemical processes it is essential that there are effective systems put in place to mitigate the variable supply situation.

Steel sector - It's important to note that in comparison to certain industries such as the fuel industry, there are currently no mandates or regulations in place for a certain percentage or steel production to come from renewable sources. As a result, in order to remain competitive, the industry would require large subsidies to absorb the additional costs. In terms of repurposing existing assets based on traditional technology, given the current coal-based nature of the steel sector, a 100% switch from coal-based production to renewable hydrogen production would be a significant and costly shift.

4.5 Concluding statements

Under **Approach A** an approximate of 10-43kton of green hydrogen will be subsidised on annual basis. This results into an approximate electrolyser capacity of 250MW to 900MW of electrolyser capacity (assuming 2,000 running hours per year).

Taking the 250MW to 900MW electrolyser capacity into account the following additional funding requests could be foreseen for the different cost categories:

- Hydrogen Production: No additional CAPEX funding requests under **Approach B** foreseen, all elements already subsidised under **Approach A**.
- Transport & Storage: Additional CAPEX foreseen for the following elements under Approach B, numbers presented are total CAPEX figures.
  - Pressurised Hydrogen Tank: €15M to €70M
  - Liquid Hydrogen Tank: €5M to €45M
  - Liquification/gasification: €120M to €145M
  - Transport trailers (Tube trailers): €27M to €38M
  - Compression systems: €10M to €45M
  - Backbone/Pipeline development: €30M to €90M
- Offtaker Application: Additional CAPEX foreseen for the following elements under Approach B, numbers presented are total CAPEX figures.

- Batteries[5]: €300k to €600k
- Low NOx burners: €1M to €17M

The results on cost figures and allocation of funding scheme of the different cost items have been verified during a workshop with different participants in the interviews. The outcomes of this interview have been incorporated into Table 3. The specific elements of this table and how they relate to the green hydrogen value chain are illustrated in Figure 2: Hydrogen value chain specifying the different elements and associated funding schemesFigure 1.

[5] Batteries to allow electrolysers operating in continuity are foreseen to be integrated in the power supply chain rather than in the green hydrogen supply chain.

A. Appendix

A.1 Additional comments

This chapter contains an overview of, in our opinion, relevant remarks made by the interviewees. Although not directly applicable for the design of the funding scheme, we deemed it appropriate to include this information in our report.

A.1.1 Simplified Approach

Certain interviewees suggested prioritising the application of a simplified approach to subsidy schemes. An example given was the manner in which subsidies are awarded in the United States under the Inflation Reduction Act's 45V Hydrogen Production Tax Credit (PTC) which awards up to $3 per kg of hydrogen produced to projects with lifecycle greenhouse gas emission (GHG) intensity of less than 0.45 kg per kg of hydrogen. We were informed that a consistent, simplified approach across the board, (as opposed to subsidies of separate components or projects) would allow companies to plan ahead with greater certainty regarding financing. It would also eliminate the need for frequent calculations, taking into account which subsidies can be applied to which elements of which projects.

A suggestion for consideration is to have evaluation criteria for the LCOH separate to the evaluation of the additional innovative components. This would result in a transparent methodology, driving innovation and overall cost reductions throughout the entire value chain.

A.1.2 Transport & Storage

Hydrogen is not only provided to large customers via pipelines, but also to a wide range of smaller industrial and mobility customers by other means such as by being compressed into cylinders or liquified for intermediate sizes. Any investment in midstream or downstream would play a significant role in smaller volumes and investment is needed, not just for pipelines but for the sixth cluster – those who can't be connected to the grid or backbone. While it's important to consider cost, it is not the only driver if decarbonisation across sectors is to be considered.

Besides subsidising large industrial clusters, it is also important to develop a renewable hydrogen value chain for small and medium enterprises (SMEs). There are around 2000 SMEs needing decarbonisation in the Netherlands, who would require smaller hydrogen flows when compared to other larger players across other industries (i.e., refineries, fertilisers, etc). If the focus is only on the cost of hydrogen production, it would favour larger industries and would put SME range companies at a disadvantage, with the cost of hydrogen supplied to off grid applications likely increasing in non-linear manner due to their lower volume of production to recover the investment which could reach tens of millions of euros.

In the case of small volume applications, i.e., those requiring fewer than 30T of hydrogen per day), hydrogen would potentially need to be transported via bulk carrier, up to a distance of 200 km from the primary production asset, resulting in LCOH €15-16 €/kgH2 (estimation from an interviewee). LCOH would be close to half of this amount for larger companies (those able to use pipelines due to the usage of higher hydrogen volumes).

Every industry using high temperature processes with limited possibility for electrification will most likely have a future demand for hydrogen, for example the steel, chemical and cement industries. When considering decarbonisation, it is important to consider mobility. For large users, the logical option would be to install electrolyser systems next to their production to reduce cost of distribution as far as possible.

A.1.3 Imports

A key point addressed by interviewees was that the same level of regulations and mandates applied to hydrogen in Europe should be applied to imported hydrogen. Many locations outside of the EU have less strict legislation concerning the production of green hydrogen, and therefore if the same requirements are not in place for import they will significantly outperform Dutch produced hydrogen on a cost per unit basis.

The EU's CBAM (Carbon Border Adjustment Mechanism) is a "tool to put a fair price on the carbon emitted during the production of carbon intensive goods that are entering the EU, and to encourage cleaner industrial production in non-EU countries.". It was raised that introducing an equivalent measure for hydrogen could be beneficial.

These measures are to avoid the need for artificially high downstream subsidies and therefore reduce LCOH.

Hydrogen import will also be expensive, with many providers at around 10€/kgH2 (LCOH) according to estimates from the interviews.

Estimation of LCOH (renewable hydrogen) from an interviewee is 6-8 €/kgH2 on a grade that can be used for mobile applications – high grade. Potentially, working on the full value chain it could be brought down to 4-4.5 €/kgH2 over the next five years assuming 4.5cent per KWH of electricity. Roughly 3 €/kg should be subsidised for a certain period of time in order to bring it to the level of grey hydrogen.

A challenge that was highlighted is the renewable energy needed to produce green hydrogen. Today in the North Sea 3.8 GW of wind farms are installed. To produce 500,000 T/year of ammonia (reasonable production for a production plant), 200,000 T/year of renewable hydrogen are required, which requires 2 GW of Wind Farms in North Sea.

A.1.4 General Offtakers

A common view among interviewees was that to reach CO2 neutrality more quickly, there should be a hierarchy among subsidising applications. For example, renewable hydrogen should be prioritised in the sectors that cannot be electrified directly such as the chemical and fertiliser industries. Another way to consider the hierarchy is by considering the relative buying power of each of the main industries listed below (chemicals, steel, SAF and fertiliser).

A common recommendation collected during the interviews is to introduce mandates that enforce green hydrogen use in end products. There are successful mandates in the biofuel market that enforce biofuel blending. For example, under the Renewable Energy Directive, EU countries are obliged to ensure that the share of renewable energy in the final consumption of energy in transport is at least 14% by 2030, including a minimum share of 3.5% of advanced biofuels.

A.1.5 SAF

It has been suggested that in order to stimulate market demand for SAF produced with renewable hydrogen it would be beneficial for the government to implement blending requirements such as those already in place for biofuels.

A.1.6 Fertiliser

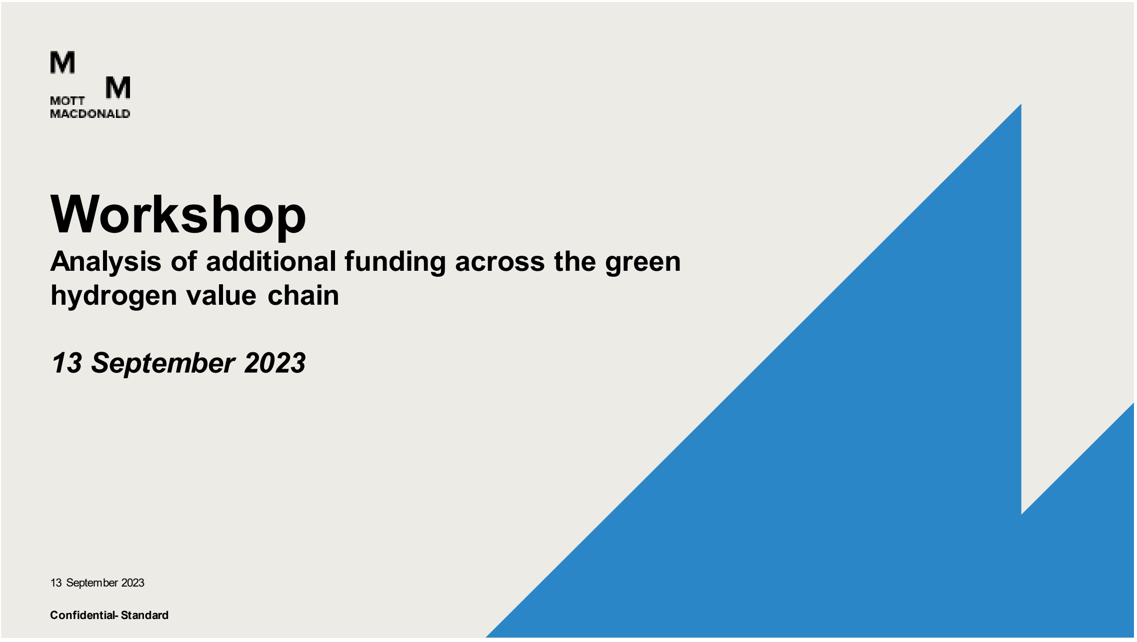
An interesting option to boost the renewable hydrogen usage in fertiliser industry is through regulatory mandates, such as the mandates set for biofuels blending. This could be a successful mechanism that could be included in chemical and fertiliser value chains, spreading costs across a much larger number of individuals, i.e., consumers, and consequently reducing the cost of subsidies.

A.1.7 Innovation and new hydrogen based products

Beyond the four sectors covered in the scope of the report, it feels important to mention that by investing in green hydrogen innovation there is potential for new products to be produced beyond those currently in the value chain. An example of this is specific protein production whose process is based on green hydrogen and that is currently under development.

A.2 Slide deck Workshops

This slidedeck was presented during the workshoip on 13 September 2023.



Mott MacDonald Core Team

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Agenda

1. Background
2. Purpose Workshop
3. Main Outcomes
4. Cost Tables
5. Next Steps

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Background

Approx. €1.0bn of subsidy is provided by EZK for the scale up of green hydrogen Production (Approach A)

Additionally, Groenvermogen intends to subsidise approx. €200 -300M the scale up of the green hydrogen value chain, other than only production (Approach B).

Approach B can only be granted to projects/parties after successful application to Approach A

Approach B intends to subsidise three categories:

1. *Hydrogen Production*
2. *Integration - Transport & Storage*
3. *Offtakers*

Focus study: Map additional components expected to apply for subsidy within the green hydrogen value chain under approach B and where possible map the expected costs

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Purpose Workshop

- **Assess logic to subsidise the cost elements listed under Approach B**
- **Assess Bandwidth of costs elements presented under Approach B**
- **Assess distinction between cost elements under Approach B and A**

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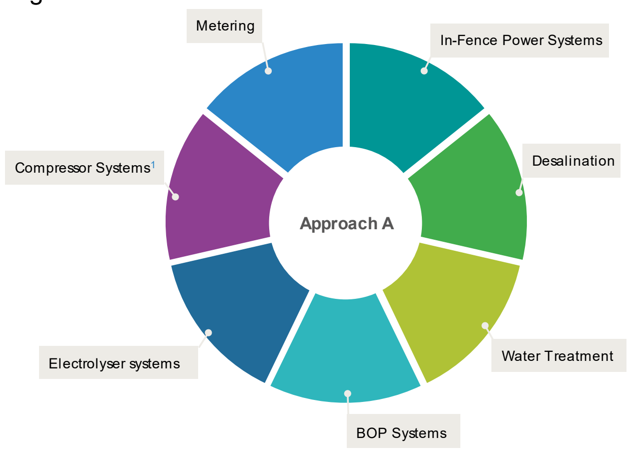
Main Outcomes

Approach A – Elements under the hydrogen Production Plant

- **Attention is asked for the design of the funding scheme.**
- **When additional funding is offered for “value chain integration”, a clear description of the base case assets for green hydrogen production is required.**
- **This to ensure that investments for assets are allocated to the appropriate cost category.**
- **A base case asset for green hydrogen production would consist of at least components listed in the diagram on the right. – THOUGHTS?**



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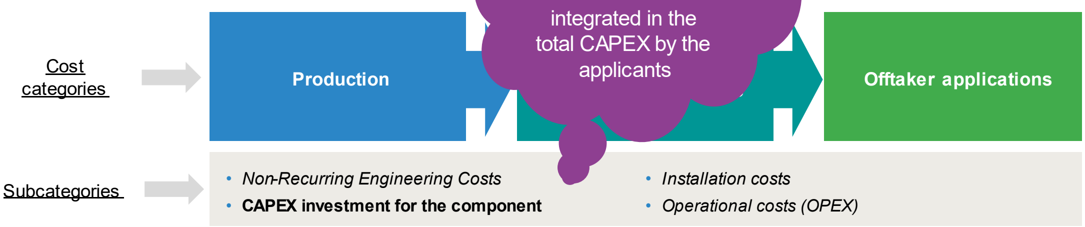
[1] Compressor systems in the hydrogen production facility are only considered to bring the hydrogen to a desired compression level to feed into a backbone system. Additional compression (e.g., hydrogen to be used in automotive at approx. 300bar) is not considered in this process element step.

Main Outcomes

Cost Categories

- **There were three major cost categories that were mentioned throughout the interviews:**
  - Production
  - Integration - Transport and storage
  - Offtaker applications
- **Within these cost categories, additional compo… subcategories: refer to below diagram.**

If only CAPEX is supported it is likely that the other cost elements will be integrated in the total CAPEX by the applicants



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Main Outcomes – Financial Overview

- **Approach A: €1.0bn subsidy allocation for a period of approx. 10 years**
- **Resulting in €100M annual subsidy allocation**

- **100 MW = approx. 4kton Hydrogen per year (at 2000 hrs/year)**
- **assuming a subsidy request of approx. €3 to 8 per kg Hydrogen**
- **Resulting in €10M to 30M yearly subsidy for a 100MW project**

- **€100M annual subsidy will result in 250MW to 900MW subsidised electrolyser capacity**
- **Resulting in a annual supported hydrogen production of 10kton to 43kton per year**

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Main Outcomes - Value Chain Integration

CAPEX estimations for 250MW to 900MW green hydrogen capacity

- **The following additional funding requests could be foreseen for the different cost categories:**

Production

- No additional CAPEX funding requests under Approach B foreseen, all elements already subsidised under Approach A.

Integration - Transport and storage

- Additional CAPEX foreseen for the following elements under Approach B, numbers presented are total CAPEX figures:

- Pressurised Hydrogen Tank: €15M to €70M
- Liquid Hydrogen Tank: €5 to €45M
- Liquification/gasification: €120M to €145M
- Transport trailers (Tube trailers): €27M to €38M
- Compression systems: €10M to €45M
- Backbone/Pipeline development: €30M to €90M

Offtaker applications

- Batteries[2]: €300k to €400k per MWh
- Low NOx burners: €1M to €17M

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[2] Batteries to allow electrolysers operating in continuity are foreseen to be integrated in the power supply chain rather than the green hydrogen supply chain.

Cost Tables – Review (Approach A, Approach B, no funding)

Cost Drivers for the hydrogen Value Chain (1) – Table 2

#	Item	Estimated Cost	Comments
		Hydrogen Production	
1	High Voltage Connections	CAPEX: • 110 and 150 kV approx. €1.5M • 220 and 380 kV approx. €3.0M	Only CAPEX figures, grid tariffs are to be paid on annual basis additionally (OPEX). OPEX Figures are dependent highly on project specific characteristics. For a 1GW plant these are estimated between €10M – €35M per year
2	In-Fence Power Systems	CAPEX: • Alkaline system: €150 -250k per MW Capacity • PEM system: €200 -300k per MW Capacity	Figures presented are for plant size from 50 -100MW capacity. For larger facilities (>2GW) costs are reduced by roughly 25%.
3	Desalination Systems	CAPEX: €2.5 – € 7.5 / MW electrolyser capacity	
4	PEM Electrolysers	CAPEX: • 50-100MW facilities: €1.250.000 – €1.600.000 per MW capacity • GW scale facility: €650.000 – €950.000 per MW capacity	Including BOP facilities
5	Alkaline Electrolysers	CAPEX • 50-100MW facilities: €1.000.000 – €1.300.000 per MW capacity • GW scale facility: €500.000 – €800.000 per MW capacity	Including BOP facilities
		Integration - Transport & Storage	
6	Hydrogen tank	CAPEX: €15.0M to €20.0M	Small scale pressurised hydrogen storage tank on site (28,000kg capacity)
7	Hydrogen liquid tank	CAPEX: €150 to €400 per kg liquid Hydrogen	Only Liquid Hydrogen storage tank
8	Liquefaction/gasification chain development	CAPEX: €120M – €150M	Liquefier CAPEX with capacity of 30T (likely to serve multiple users)
9	Transport trailers (Tube Trailer)	CAPEX: €600k – €900k 1 Tube trailer	20 MW electrolyser (~2000 h/year) → 4 tube trailers daily with capacity ~600kg H_2 → €2.4 – €3.6M
10	Filling Centre	CAPEX: €20M to €30M	Filling centre CAPEX with capacity of 10T. It must not be related to transport purposes to be funded
11	Conditioning and purification of hydrogen	N/A	No cost data available Postproduction purification likely not required
12	Compression systems	CAPEX: €0.9M to €1.3M per MW compression capacity	Highly dependent on compression approach (e.g., atm to 50 bar or 15 bar to 50 bar) and specific plant capacity
13	Salt cavern based stock development [3]	Additional increase of LCOH of €0.07 to €0.47 per kg hydrogen	Additional costs for storing hydrogen in salt caverns.

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Cost Tables – Review (Approach A, Approach B, no funding)

Cost Drivers for the hydrogen Value Chain (2) – Table 2

#	Item	Estimated Cost	Comments
		Integration - Transport & Storage	
~~14~~	~~Generic - buffer development~~	~~N/A~~	~~Cost figures presented under: 6) for high pressure hydrogen tank. 7) for liquified hydrogen 9) for tube trailers 13) for salt caverns~~ Cost already included in other line items.
15	Connection to Backbone / Pipeline connection to industry	CAPEX: €1.5M –€3.5M per km	CAPEX Highly dependent on site characteristics, method of construction and pipe characteristics. GNVL and EZK to decide if to be funded (Approach A or Approach B) or not. Pipeline development considered necessary for Cluster 6 industries
16	Boil-off Reduction (Liquid Hydrogen)	In a 30T system boil -off cost are €12k - €30k per dispense	Rough estimation of boil -off is about 10% (each time the hydrogen is dispensed)
17	Hydrogen Carriers (example: ammonia)	€650 to €1300/T ammonia [4]	Production costs for green ammonia using green hydrogen as feedstock
		Offtaker Applications	
18	Batteries to allow electrolysers operating in continuity	CAPEX: €300k – 600k per MWh installed capacity	For Battery Energy Storage System, to allow for running electrolyser continuously. Purpose: ramp rate control (ie. not for market reason). Question: could also be under "Integration - Transport & Storage" cost category. GNVL and EZK to decide if to be funded (Approach A or Approach B) or not.
19	Low NOx burner	CAPEX: to convert heat production equipment (including and not limited to burner) methane to H2: €400k –1M for 10MW	Indicative overall estimation for offtakers applications
20	General - Grey hydrogen producing assets impact: Minor SMR capacity reduction	N/A	From rough estimation, grey hydrogen existing assets (example SMR) can still work after applying modifications if their capacity reduction is minor due to replacement with green hydrogen. Costs to be estimated for each business case. CAPEX Highly dependent on site characteristics, method of construction and pipe characteristics. GNVL and EZK to decide if to be funded or not.
21	General - Grey hydrogen producing assets impact: Major SMR capacity reduction	N/A	From rough estimation, grey hydrogen existing assets (example SMR) cannot operate anymore if their capacity reduction is major due to replacement with green hydrogen. Costs to be estimated for each business case. GNVL and EZK to decide if to be funded or not.
22	General - Grey hydrogen producing assets impact: loss of production	N/A	No cost data available, different for each business case. dependent on actual loss of production and remaining planned operational lifetime installation. Feedback from 13 -09 afternoon session: GNVL and EZK to decide if to be funded (Approach B) or not, considered to be excluded from the funding
23	General - Adapting to green hydrogen: final application process impact. Costs for training, increased operations, recruitment of additional staff, eventual automation and certification	N/A	No cost data available, different for each business case.

Cost Tables – Review (Approach A, Approach B, no funding)

Cost Drivers for the hydrogen Value Chain (2) – Table 2

#	Item	Estimated Cost	Comments
		Integration - Transport & Storage	
~~14~~	~~Generic - buffer development~~	~~N/A~~	~~Cost figures presented under: 6) for high pressure hydrogen tank. 7) for liquified hydrogen 9) for tube trailers 13) for salt caverns~~ Cost already included in other line items.
15	Connection to Backbone / Pipeline connection to industry	CAPEX: €1.5M – €3.5M per km	CAPEX Highly dependent on site characteristics, method of construction and pipe characteristics. GNVL and EZK to decide if to be funded (Approach A or Approach B) or not. Pipeline development considered necessary for Cluster 6 industries
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23	General - Adapting to green hydrogen: final application process impact. Costs for training, increased operations, recruitment of additional staff, eventual automation and certification	N/A	No cost data available, different for each business case.

Cost Tables – Review (Approach A, Approach B, no funding)

Additional components necessary to accelerate the green hydrogen value chain – Table 3

#	Item	Estimated Cost	Comments
1	Integrated test facilities to develop electrolysers vs scale-up (larger than 1 MW)	Rough Estimation: €10M – €50M	No cost data available. Main cost drivers regarding test facilities are currently under evaluation by GVNL separately
2	Development of innovative electrolysers (example: pressurisation, etc) vs scaleup	N/A	No cost data available. R&D programmes are funded separately
3	Development of low content rare materials (i.e., PGM, etc) electrolysers vs scaleup	N/A	No cost data available. R&D programmes are funded separately.
4	Integrated test facilities to develop components/systems (related to Transport and Storage) vs scale-up	N/A	No cost data available. Main cost drivers regarding test facilities are currently under evaluation by GVNL separately.
5	New products development, out of current value chains (example of DMS working on new proteins based on H2	N/A	No Cost data available

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Next steps

- **Process results of workshop**
- **Issue revised version of report**

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Thank you

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