Annexes to the H-vision Main Report

Contents

1 Annex to chapter 4: The solution space – a scenario approach

The term 'Solution Space' captures the conceptual model behind the Assess and Select phase of H-vision. It may be portrayed by the area with on one axis the development concepts ('our world' that we control, we decide) and on the other axis the scenarios ('outside world' that we cannot control).

Main objective of the 'Assess' phase is to understand the 'Solution Space' and to demonstrate that a certain development concept is robust i.e. is feasible in most scenarios. The 'Solution Space' helps prioritizing resources and efforts that will be required to decide on the selection of an optimum development concept.

This chapter describes the H-vision development concepts and the primary decisions that must be made along the entire value chain (supply, production, transport, flexibility and end-use). Also, the scenarios and the key uncertainties i.e. those that may swing the concept, are described.

1.1 Solution space - methodology & terminology

Methodology & terminology

The term 'Solution Space' captures the mental model behind the H-vision project phases 'Assess' and 'Select' (Figure 6.C). It may be portrayed by the area, on one axis defined by the development concepts ('our world' that we control, we decide) and on the other axis the scenarios ('outside world' that we cannot control).

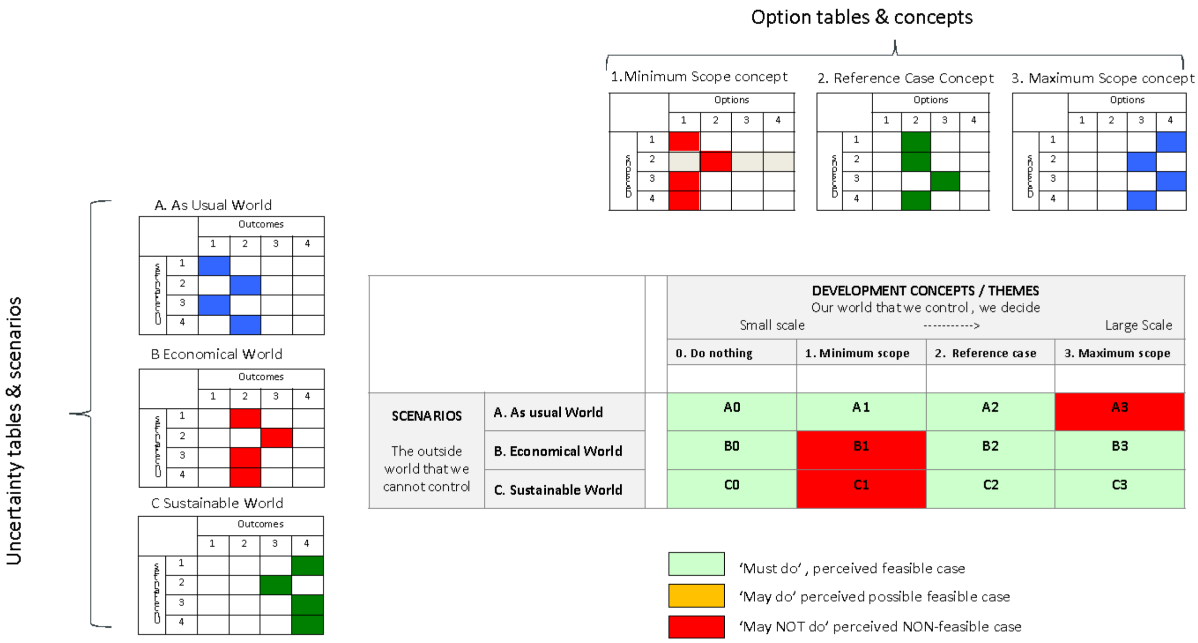

Figure 1.A: building the solution space & case mapping

The important elements that make-up the solution space and the key questions are:

- **Decision tables & development concepts**: What solutions do we have? Is the range of technical/development concepts wide enough? We identify the primary decisions (i.e.

those which may swing the concept) & associated options to choose from. We collect them in an option table and define various ‘concepts’ by combining possible options. We are in full control of the options we choose.

- **Uncertainty tables & scenarios**: What can the world do to us? Is the range of ‘scenarios’ wide enough? We identify the key TECOP (technical, economical, commercial, organizational and political) uncertainties (i.e. those which may swing the concept) & the associated possible outcomes. We collect them in an uncertainty table and define various ‘scenarios’ by combining/stringing possible outcomes. We are not in control of the outcomes.
- **Solution space & cases**: What are the better solutions? Is there at least one realistic concept that is robust against perhaps all scenarios? A ‘case’ is defined as a combination between a ‘scenario’ and a ‘development’ scope. Case mapping is the process of identifying various cases i.e. building the solution space. For example and four different ‘development concepts’ and three different ’scenarios’ results in twelve cases. The ‘Assess’ phase is all about understanding the ‘Solution Space’ and demonstrating that a certain development scopes works most of the time. It is about prioritizing resources and efforts that will be required to decide on the selection of the optimum development scope. This means that we do not need to understand all corners of the ‘Solution Space’ to the same degree.

1.2 Decisions and development concepts

The primary decisions (i.e. those which may swing the concept) along the entire value chain and the options to choose from were collected in the decision table (Table 1.F). This table is fundamental for the definition of each of the following development scopes:

1.2.1 0 Do nothing

It is assumed that the existing coal plants in the Port of Rotterdam area will be converted to biomass and that the subsequent deficit in electricity production will be covered by the existing gas power plants. The load factor of these power plants is expected to decrease.

End-user	Minimum scope		Reference scope		Maximum scope	
	Max hydrogen demand [MW]	CO_2 capture [Mtpa]	Max hydrogen demand [MW]	CO_2 capture [Mtpa]	Max hydrogen demand [MW]	CO_2 capture [Mtpa]
Engie Maasvlakte power plant	174	0.2	805	1.0	1066	1.4
Uniper Maasvlakte power plant	217	0.3	805	1.0	1131	1.5
Pergen steam and power NG	143	0.3	286	0.6	571	1.3
BP refinery RFG	250	0.6	520	1.1	520	1.1
BP refinery NG	40	0.1	40	0.1	40	0.1
Shell Pernis refineriy RFG	250	0.6	650	1.4	650	1.4
Shell Pernis refineriy NG	50	0.1	100	0.2	100	0.2
Exxon + Gunvor refineries RFG	-	-	-	-	600	1.3
Additional users NG	-	-	-	-	500	1.1
TOTALS	1,190	2.2	3,210	5.5	5,280	9.4

Table 1.A: Overview hydrogen demand and CO_2 capture

1.2.2 1 Minimum scope – minimum revamp

The minimum scope concept (Table 1.G) comprises minimal adjustments to the existing refineries and power plants (minimum revamp).

The hydrogen will be made from natural gas (NG) and/or refinery gas (RFG) through one or more production plants at the Maasvlakte. The oxygen supply will be through a new dedicated O2 plant. The maximum foreseen hydrogen production capacity of 1,190 MW will be ramped up in 5 years and the hydrogen will be used for:

- 10% hydrogen firing for preheating the Engie Maasvlakte (174 MW) and Uniper Maasvlakte (217 MW) coal-fired power plants (total of 391 MW) in addition to steam integration
- Replacement of NG 25% of the Pergen CHP plant (143 MW)
- Replacement of RFG of the BP (250 MW) and Shell Pernis refineries (250 MW)
- Replacement of NG imported to balance the fuel gas (FG) grid of the BP (40 MW) and Shell Pernis refineries (50 MW). This excludes the NG duty of the gas turbines.

The minimum CO_2 capture rate of the reformers will be circa 88% resulting in a maximum (corresponding to 100% run-hours at full load) CO_2 volume of circa 2.2 Mtpa, that will be transported and stored through Porthos. The hydrogen fuel will be transported through a new local pipeline in a new distribution grid. Short- and long-term flexibility will be provided through flexible production and hence no hydrogen storage is required.

1.2.3 2 Reference scope - no regret/ accelerated CO_2 reduction :

The reference scope (Table 1.H) comprises very significant adjustments to the existing refineries and power plants (no regret /accelerated CO_2 reduction).

The hydrogen will be made from NG and/or RFG through a single ATR reformer plant at a single location at the Maasvlakte. The foreseen hydrogen production capacity of 3,210 MW max will be ramped up in 5 years and the hydrogen will be used for:

- Firing the 2x140 MW GT turbines of the Engie Maasvlakte and Uniper Maasvlakte power plants, fully integrated with the existing boiler (topping cycle +heat integration) and steam integration (2x805 MW)
- Replacement of NG 50% of the Pergen CHP plant (286 MW)
- Maximum replacement of RFG of the BP (520 MW) and Shell Pernis refineries (650 MW)
- Replacement of NG imported to balance the fuel gas (FG) grid of the BP (40 MW) and Shell Pernis refineries (100 MW). This still excludes the NG duty of the gas turbines.

The minimum CO_2 emission capture rate of the reformers is 88% resulting in a maximum (corresponding to 100% run-hours at full load) CO_2 volume of circa 5.5 Mtpa that will be transported and stored through Porthos. The hydrogen fuel will be transported to the end-users through a new local pipeline in a new distribution grid. Short- and long-term flexibility will be provided through flexible production and network storage (line packing).

1.2.4 3 Maximum scope – outlook beyond the H-vision participants

The maximum scope (Table 1.I) comprises maximum possible adjustments to the existing refineries and power plants of the H-vision participants (no regret /accelerated CO_2 reduction) and adjustments to the installations of third parties (Exxon, Gunvor and other nearby NG users).

The Shell Moerdijk chemical plant has not (yet) been included in the maximum scope concept, but is a possible add-on as described in more detail in the technical report of the H-vision project.

The hydrogen will be made from NG and/or RFG through one or more ATR plants preferably at a single location at the Maasvlakte. The oxygen supply will be through a new dedicated O2 plant. The foreseen maximum Hydrogen production capacity of 5,200 MW will be achieved in 2030 and the hydrogen will be used for:

- Firing the 2x140 MW GT turbines of the Engie Maasvlakte (1066 MW) and Uniper Maasvlakte (1131 MW) power plants, fully integrated with the existing boiler (topping cycle +heat integration) and steam integration. In addition, 15% hydrogen firing for preheating the BFW preheat section or direct firing of the boiler is foreseen. Total hydrogen duty is foreseen 2197 MW)
- Replacement of NG 100% of the Pergen CHP plant (571 MW)
- Maximum replacement of RFG of the BP (520 MW) and Shell Pernis refineries (650 MW)
- Replacement of NG imported to balance the fuel gas (FG) grid of the BP (40 MW) and Shell Pernis refineries (100 MW). This still excludes the NG duty of the gas turbines.
- Replacement of RFG of the Exxon and Gunvor refineries (estimated 600 MW)
- Additional users of NG such as Exxon, Gunvor, Air Liquid, Air Products, Huntsman and LyondellBasell (estimated 500 MW)

The CO_2 emission capture rate of the reformers will be circa 88% resulting in a maximum (corresponding to 100% run-hours at full load) CO_2 volume of circa 9.4 Mtpa that will be transported and stored through an up-scaled Porthos + (extended CO_2 pipeline). The hydrogen will be transported to the end-users through a new distribution grid. Transport will be through a new dedicated pipeline network. Short- and long-term flexibility will be provided through flexible production, dual firing (NG, FG and hydrogen) and the use of large-scale underground storage in salt caverns or near-depleted gas fields.

1.3 Uncertainties and Scenarios

The key uncertainties are the ones that may swing the choice of the optimum H-vision development concept. These uncertainties and the associated possible outcomes are collected in an uncertainty table (Table 1.B). This uncertainty table is fundamental for the definition of H-vision ‘scenarios’. The range of outcomes is expressed from low, medium to high, where a low and high means that the outcome is ‘NOT favourable’ respectively ‘favourable’ for the successful realisation of the H-vision project as per the mission statement.

KEY UNCERTAINTIES [1]		RANGE OF OUTCOMES		
		LOW NOT favourable [2]	MID	HIGH Favourable [2]
TECHNICAL	Hydrogen national backbone capacity (GW)	NONE	Med 10 GW	High 20 GW
	Hydrogen external storage availability	Low (1day)	Med (1 week)	High (2 weeks)
	Electrification industry (PJ)	High 20 PJ	Mid 13 PJ	None
COMMERCIAL ECONOMICS	CO_2 market/price (€/ton) [3] 2020-2045	Low 17-44 IEA New Policies	N/A	High 17-149 IEA Sustainable world
	Gas market/price (€/MWh) [3] 2020-2045	High 18-34 PBL - klimaatakkoord	Med 18-29 IEA New Policies	Low 18-24 IEA Sustainable world
	CO_2 tariff (€/ton) [4]	High 45	Med 30	Low 22.5
	CAPEX	+150%	100%	75%
POLITICAL	Political/societal support Porthos	Opposition	Sufficient	Full

Table 1.B: H-vision uncertainty table

The presence of a hydrogen national backbone would enable the offset potential of the produced hydrogen beyond the Port of Rotterdam area and hence would have a positive effect on the project. A high degree of electrification of the industry (20PJ), when flexible in nature, would compete with blue hydrogen as supplier of heat and power. From the other hand a low natural gas price of 18 €/MWh in 2020 increasing to only 24 €/MWh in 2045 (as per the IEA sustainable world scenario) is favourable for the project because natural gas serves as a feedstock for the production of blue hydrogen.

The same obviously applies to 'low' CO_2 tariffs for transport and storage (OPEX) and a relatively 'low' project CAPEX. In case the Porthos CCUS project forestalls due to political/societal opposition, an alternative CO_2 evacuation route most likely has a detrimental effect on the cost and schedule and hence on the overall H-vision feasibility.

The number of scenarios has been limited to three. They are predominantly based on the IEA's 'Current Policies' and 'Sustainable Development' scenarios (International Energy Agency, 2018) in combination with the latest PBL price forecasts for the draft NL climate agreement (PBL, 2019).

The scenarios are explained in the World Energy Outlook as follows:

[1] *Key uncertainties (from the consortium perspective) i.e. those that may swing the H-vision development concept.*

[2] *'NOT favourable' / 'Favourable' relates to the successful realisation of the H-vision project as per the Mission Statement*

[3] *Price bandwidth sceario's adjusted from Nationale Energie Verkenning 2017 (ECN/PBL/CBS/RVO) indicated prices from 2020 to 2045, IEA's World Energy Outlook 2018*

[4] *CO2 tariff for transport & storage through Porthos or alternative evacuation route*

The ***Current Policies Scenario*** *(CPS) considers the impact of only those policies and measures that are firmly enshrined in legislation as of mid-2018. In addition, where existing policies target a range of outcomes, it is assumed that the lower end of the range is achieved. In this way, CPS provides a cautious assessment of where existing policies might lead the energy sector in the absence of additional impetus from governments. It provides a benchmark against which the impact of "new policies" can be measured.*

The **Sustainable Development Scenario** *(SDS) was introduced for the first time in the WEO-2017. Unlike the other main scenarios, it starts from the objectives to be achieved and then assesses what combination of actions would deliver them. These objectives are derived from the Sustainable Development Goals (SDGs) of the United Nations, providing an energy sector pathway that achieves: universal access to affordable, reliable and modern energy services by 2030 (SDG 7.1); a substantial reduction in air pollution (SDG 3.9); and effective action to combat climate change (SDG 13). On the latter point, the Sustainable Development Scenario is fully aligned with the goal of the Paris Agreement to hold the increase in the global average temperature to well below 2 °C above pre-industrial levels. This scenario lays out an integrated strategy for the achievement of these important policy objectives, while also having a strong accent on energy security."*

These two IEA scenarios provide a potential range of outcomes, however, it lacks a significant sensitivity for the natural gas prices. For that reason, the Economical World scenario is introduced. The CO_2 prices are the same as in the Sustainable world scenario, but in combination with much higher gas prices. This scenario could materialize if through policy measures CO_2 prices will go up comparable to the Sustainable World scenario, but at the same time the economic growth is much stronger and demand for commodities such as oil and gas is still going up significantly.

The H-vision scenarios are therefore defined as follows:

A 'As usual world'

The As Usual (AU) world scenario reflects a situation where no ground breaking new policies or developments occur and where prices and key technologies follow the current trend and there is no accelerated CO_2 reduction. This scenario is based on similar assumption as the IEA current policies scenario

KEY UNCERTAINTIES [1]		RANGE OF OUTCOMES		
		LOW NOT favourable [2]	MID	HIGH Favourable [2]
TECHNICAL	Hydrogen national backbone capacity (GW)	NONE	Med 10 GW	High 20 GW
	Hydrogen external storage availability	Low (1day)	Med (1 week)	High (2 weeks)
	Electrification industry (PJ)	High 20 PJ	Mid 13 PJ	None

COMMERCIAL ECONOMICS	CO_2 market price (€/ton) [3] 2020-2045	Low 17-44 IEA New Policies	N/A	High 17-149 IEA Sustainable world
	Gas market price (€/MWh) [3] 2020-2045	High 18-34 PBL - klimaatakkoord	Med 18-29 IEA New Policies	Low 18-24 IEA Sustainable world
	CO_2 tariff (€/ton) [4]	High 45	Med 30	Low 22.5
	CAPEX	+150%	100%	75%
POLITICAL	Political/societal support Porthos	Opposition	Sufficient	Full

Table 1.C: The 'As Usual World' scenario. Footnotes can be found below Table 1.B.

In the AU world, the expectation is that only limited blue hydrogen projects will be developed. As such a national Hydrogen Backbone and larger storage facility will not be developed. Because of modest electricity prices, in combination with the continued development of wind and PV, some electrification will occur, where it makes economic sense

B 'Economical world'

The Economical world (EW) reflects strong economic growth and a continuing ambition to meet climate goals that leads to resource constraints, increasing prices (both commodities and CO_2 certificates) and accelerated development of key technologies.

KEY UNCERTAINTIES [1]		RANGE OF OUTCOMES		
		LOW NOT favourable [2]	MID	HIGH Favourable [2]
TECHNICAL	Hydrogen national backbone capacity (GW)	NONE	Med 10 GW	High 20 GW
	Hydrogen external storage availability	Low (1day)	Med (1 week)	High (2 weeks)
	Electrification industry (PJ)	High 20 PJ	Mid 13 PJ	None
COMMERCIAL ECONOMICS	CO_2 market price (€/ton) [3] 2020-2045	Low 17-44 IEA New Policies	N/A	High 17-149 IEA Sustainable world
	Gas market price (€/MWh) [3] 2020-2045	High 18-34 PBL - klimaatakkoord	Med 18-29 IEA New Policies	Low 18-24 IEA Sustainable world
	CO_2 tariff (€/ton) [4]	High 45	Med 30	Low 22.5
	CAPEX	+150%	100%	75%
POLITICAL	Political/societal support Porthos	Opposition	Sufficient	Full

Table 1.D: The 'Economical World' scenario. Footnotes can be found below Table 1.B.

In the EW scenario, the expectation is that many blue and later green hydrogen projects will be developed. As such a national Hydrogen Backbone and larger storage facility will be developed. Because of modest electricity prices, in combination with the continued development of wind and PV, some electrification will occur, where it makes economic sense

C 'Sustainable world'

The basis of IEAs sustainable world scenario is that CO_2 emissions will be sufficiently lower to ensure a max 2°C increase of global average temperature compared to pre-industrial times. The 'Sustainable world' reflects the implementation of stringent climate policies that leads to shortage on the CO_2 market on the one hand, but also to economic distress on the other hand. The result is an increase in CO_2 prices, but a decrease of the other prices such as for natural gas.

KEY UNCERTAINTIES [1]		RANGE OF OUTCOMES		
		LOW NOT favourable [2]	MID	HIGH Favourable [2]
TECHNICAL	Hydrogen national backbone capacity (GW)	NONE	Med 10 GW	High 20 GW
	Hydrogen external storage availability	Low (1day)	Med (1 week)	High (2 weeks)
	Electrification industry (PJ)	High 20 PJ	Mid 13 PJ	None
COMMERCIAL ECONOMICS	CO_2 market price (€/ton) [3] 2020-2045	Low 17-44 IEA New Policies	N/A	High 17-149 IEA Sustainable world
	Gas market price (€/MWh) [3] 2020-2045	High 18-34 PBL - klimaatakkoord	Med 18-29 IEA New Policies	Low 18-24 IEA Sustainable world
	CO_2 tariff (€/ton) [4]	High 45	Med 30	Low 22.5
	CAPEX	+150%	100%	75%
POLITICAL	Political/societal support Porthos	Opposition	Sufficient	Full

Table 1.E: The 'Sustainable World' scenario. Footnotes can be found below Table 1.B.

1.4 Decision table (or Option table)

BUILDING BLOCK	DECISIONS	OPTIONS					
		1	2	3	4	5	6
GENERAL	CO_2 storage volume	2 Mton CO_2 / year	6 Mton CO_2 / year	10 Mton CO_2 / year			
	Hydrogen use	Heat	Heat + Power	Heat + power + feedstock			
	Hydrogen quality, composition	Caloric quality	Feedstock quality	Ultra-pure quality			
SUPPLY	Feedstock	Natural gas	Refinery gas (incl NG balancing)	Natural gas + Refinery gas			

	Supply line natural gas	Use existing pipeline	New dedicated pipeline				
	Oxygen supply	Commercial supply	New dedicated O2 plant	Ex Green hydrogen			
PRODUCTION	Production location	De-central plants	Central plant(s)				
	Hydrogen potential capacity for Heat (PJ)	Min	Med	Max			
	Hydrogen potential capacity for Power (PJ)	Min	Med	Max			
	Hydrogen capacity staircase ramp-up (yrs)	10	5	3			
	Hydrogen production technology (incl CCS)	GHR (Gas Heated Reforming)	SMR or POX	ATR	Combined		
	CO_2 emission capture of reformer (%)	Min 80%	Med 90%	Max 94% (H21)	N/A		
TRANSPORT	Blue hydrogen	Use existing pipeline (high purity)	New local pipeline	New dedicated pipeline network			
	CO_2 evacuation	Porthos CO_2 pipeline	Porthos+ Extended CO_2 pipeline	Alternative route (Export)			
FLEXIBILITY	Short term (Day)	Flexible production	Storage (days)	Dual firing (natural/fuel gas + hydrogen)			
	Long term (Season)	Flexible production	Storage (weeks)	Dual firing (natural/fuel gas + hydrogen)			
	Storage type	N/A	Pressurized tanks	Network (line packing)	Cryogenic	Ammonia	Subsurface
END-USE	Converting coal fired power plants	Only preheat (10%) (±195 MW + steam)	Topping cycle (±805 MW + steam)	Preheat (15%) + Topping cycle + Steam (±1098 MW)			
	Pergen CHP plant	25% replacement (143 MW)	50% replacement (286 MW)				
	Refinery demand – Refinery fuel gas	Low: BP + Shell (247 + 250MW)	Med: BP + Shell (520 + 650 MW)	High: BP + Shell + Exxon& Gunvor (520 + 650 + 600 MW)			
	Refinery demand – Natural gas	Low: BP + Shell (40 + 50 MW)	High: BP + Shell (40 + 100 MW)				
	Other Natural gas demand	None	Nearby end-users (500 MW)				

	Flexible firing	N	Y				

Table 1.F: Decision (option) table

1.5 Development concept 1 'Minimum scope – minimum revamp'

BUILDING BLOCK	DECISIONS	OPTIONS					
		1	2	3	4	5	6
GENERAL	CO_2 storage volume	2 Mton CO_2 / year	6 Mton CO_2 / year	10 Mton CO_2 / year			
	Hydrogen use	Heat	Heat + Power	Heat + power + feedstock			
	Hydrogen quality, composition	Caloric quality	Feedstock quality	Ultra-pure quality			
SUPPLY	Feedstock	Natural gas	Refinery gas (incl NG balancing)	Natural gas + Refinery gas			
	Supply line natural gas	Use existing pipeline	New dedicated pipeline				
	Oxygen supply	Commercial supply	New dedicated O2 plant	Ex Green hydrogen			
PRODUCTION	Production location	De-central plants	Central plant(s)				
	Hydrogen potential capacity for Heat (PJ)	Min	Med	Max			
	Hydrogen potential capacity for Power (PJ)	Min	Med	Max			
	Hydrogen capacity staircase ramp-up (yrs)	10	5	3			
	Hydrogen production technology (incl CCS)	GHR (Gas Heated Reforming)	SMR or POX	ATR	Combined		
	CO_2 emission capture of reformer (%)	Min 80%	Med 90%	Max 94% (H21)	N/A		
TRANSPORT	Blue hydrogen	Use existing pipeline (high purity)	New local pipeline	New dedicated pipeline network			
	CO_2 evacuation	Porthos CO_2 pipeline	Porthos+ Extended CO_2 pipeline	Alternative route (Export)			
FLEXIBILITY	Short term (Day)	Flexible production	Storage (days)	Dual firing (natural/fuel gas + hydrogen)			
	Long term (Season)	Flexible production	Storage (weeks)	Dual firing (natural/fuel gas + hydrogen)			
	Storage type	N/A	Pressurized tanks	Network (line packing)	Cryogenic	Ammonia	Subsurface

END-USE	Converting coal fired power plants	Only preheat (10%) (±195 MW + steam)	Topping cycle (±805 MW + steam)	Preheat (15%) + Topping cycle + Steam (±1098 MW)			
	Pergen CHP plant	25% replacement (143 MW)	50% replacement (286 MW)				
	Refinery demand – Refinery fuel gas	Low: BP + Shell (247 + 250MW)	Med: BP + Shell (520 + 650 MW)	High: BP + Shell + Exxon& Gunvor (520 + 650 + 600 MW)			
	Refinery demand – Natural gas	Low: BP + Shell (40 + 50 MW)	High: BP + Shell (40 + 100 MW)				
	Other Natural gas demand	None	Nearby end-users (500 MW)				
	Flexible firing	N	Y				

Table 1.G: Minimum scope decision table

1.6 Development concept 2 'Reference case - no regret/ accelerated CO_2 reduction'

BUILDING BLOCK	DECISIONS	OPTIONS					
		1	2	3	4	5	6
GENERAL	CO_2 storage volume	2 Mton CO_2 / year	6 Mton CO_2 / year	10 Mton CO_2 / year			
	Hydrogen use	Heat	Heat + Power	Heat + power + feedstock			
	Hydrogen quality, composition	Caloric quality	Feedstock quality	Ultra-pure quality			
SUPPLY	Feedstock	Natural gas	Refinery gas (incl NG balancing)	Natural gas + Refinery gas			
	Supply line natural gas	Use existing pipeline	New dedicated pipeline				
	Oxygen supply	Commercial supply	New dedicated O2 plant	Ex Green hydrogen			
PRODUCTION	Production location	De-central plants	Central plant(s)				
	Hydrogen potential capacity for Heat (PJ)	Min	Med	Max			
	Hydrogen potential capacity for Power (PJ)	Min	Med	Max			
	Hydrogen capacity staircase ramp-up (yrs)	10	5	3			
	Hydrogen production technology (incl CCS)	GHR (Gas Heated Reforming)	SMR or POX	ATR	Combined		
	CO_2 emission capture of reformer (%)	Min 80%	Med 90%	Max 94% (H21)	N/A		
TRANSPORT	Blue hydrogen	Use existing pipeline (high purity)	New local pipeline	New dedicated pipeline network			
	CO_2 evacuation	Porthos CO_2 pipeline	Porthos+ Extended CO_2 pipeline	Alternative route (Export)			
FLEXIBILITY	Short term (Day)	Flexible production	Storage (days)	Dual firing (natural/fuel gas + hydrogen)			

	Long term (Season)	Flexible production	Storage (weeks)	Dual firing (natural/fuel gas + hydrogen)			
	Storage type	N/A	Pressurized tanks	Network (line packing)	Cryogenic	Ammonia	Subsurface
END-USE	Converting coal fired power plants	Only preheat (10%) (±195 MW + steam)	Topping cycle (±805 MW + steam)	Preheat (15%) + Topping cycle + Steam (±1098 MW)			
	Pergen CHP plant	25% replacement (143 MW)	50% replacement (286 MW)				
	Refinery demand – Refinery fuel gas	Low: BP + Shell (247 + 250MW)	Med: BP + Shell (520 + 650 MW)	High: BP + Shell + Exxon& Gunvor (520 + 650 + 600 MW)			
	Refinery demand – Natural gas	Low: BP + Shell (40 + 50 MW)	High: BP + Shell (40 + 100 MW)				
	Other Natural gas demand	None	Nearby end-users (500 MW)				
	Flexible firing	N	Y				

Table 1.H: Reference scope decision table

1.7 Development concept 3 ‘Maximum scope – outlook beyond the H-vision participants’

BUILDING BLOCK	DECISIONS	OPTIONS					
		1	2	3	4	5	6
GENERAL	CO_2 storage volume	2 Mton CO_2 / year	6 Mton CO_2 / year	10 Mton CO_2 / year			
	Hydrogen use	Heat	Heat + Power	Heat + power + feedstock			
	Hydrogen quality, composition	Caloric quality	Feedstock quality	Ultra-pure quality			
SUPPLY	Feedstock	Natural gas	Refinery gas (incl NG balancing)	Natural gas + Refinery gas			
	Supply line natural gas	Use existing pipeline	New dedicated pipeline				
	Oxygen supply	Commercial supply	New dedicated O2 plant	Ex Green hydrogen			
PRODUCTION	Production location	De-central plants	Central plant(s)				
	Hydrogen potential capacity for Heat (PJ)	Min	Med	Max			
	Hydrogen potential capacity for Power (PJ)	Min	Med	Max			
	Hydrogen capacity staircase ramp-up (yrs)	10	5	3			
	Hydrogen production technology (incl CCS)	GHR (Gas Heated Reforming)	SMR or POX	ATR	Combined		
	CO_2 emission capture of reformer (%)	Min 80%	Med 90%	Max 94% (H21)	N/A		
TRANSPORT	Blue hydrogen	Use existing pipeline (high purity)	New local pipeline	New dedicated pipeline network			
	CO_2 evacuation	Porthos CO_2 pipeline	Porthos+ Extended CO_2 pipeline	Alternative route (Export)			
FLEXIBILITY	Short term (Day)	Flexible production	Storage (days)	Dual firing (natural/fuel gas + hydrogen)			
	Long term (Season)	Flexible production	Storage (weeks)	Dual firing (natural/fuel gas + hydrogen)			

	Storage type	N/A	Pressurized tanks	Network (line packing)	Cryogenic	Ammonia	Subsurface
END-USE	Converting coal fired power plants	Only preheat (10%) (±195 MW + steam)	Topping cycle (±805 MW + steam)	Preheat (15%) + Topping cycle + Steam (±1098 MW)			
	Pergen CHP plant	25% replacement (143 MW)	50% replacement (286 MW)				
	Refinery demand – Refinery fuel gas	Low: BP + Shell (247 + 250MW)	Med: BP + Shell (520 + 650 MW)	High: BP + Shell + Exxon& Gunvor (520 + 650 + 600 MW)			
	Refinery demand – Natural gas	Low: BP + Shell (40 + 50 MW)	High: BP + Shell (40 + 100 MW)				
	Other Natural gas demand	None	Nearby end-users (500 MW)				
	Flexible firing	N	Y				

Table 1.I: Maximum scope decision table

2 Annex to chapter 5: Markets

2.1 Hydrogen Market Development

2.1.1 Hydrogen market potential

In the efforts to reduce CO_2 emissions, the focus so far has been mainly on reducing the CO_2 footprint of electricity production and converting energy demand to electricity. However, for the Netherlands to reach its climate targets in 2030 and 2050, it is unlikely that full electrification is feasible for the industry and that other energy carriers will still be required in the form of molecules (as opposed to electrons). Various studies have concluded that there will be a need to deploy 'clean molecules' in order to keep the costs within an acceptable range. In a study (Berenschot, 2018), Berenschot showed this need for developing clean molecules next to clean electrons.

Today, there is already an established hydrogen market, in which hydrogen is primarily used as a feedstock and primarily produced by reforming natural gas.

> "In the future, however, the market for hydrogen may grow strongly. In fact, hydrogen is increasingly seen as a potential energy carrier to provide high-temperature process heat, to heat buildings and produce electricity while it is also expected that it can become a major fuel in transport (CertifHy, 2016) (CE Delft, 2018) (Hydrogen Council, 2017) (International Energy Agency, 2017) (Waterstof Coalitie, 2018) (IRENA, 2018) (World Energy Council, 2018). In addition, hydrogen may play a role to help the electricity sector to deal with the increasing shares of renewable power by offering flexibility regarding the timing and location of production."
>
> Source: *Outlook for a Dutch hydrogen market* (Mulder, Perey, & Moraga, 2019)

In this study, we limit our focus to deploying hydrogen as a source of energy for large industrial production units and for power production (including coal-fired power plants) in the Rotterdam port area. Nevertheless, if this concept is successfully developed, it could pave the way to convert other related market segments to hydrogen as well, for example in the city of Rotterdam and the surrounding area. Moreover, additional opportunities can arise by connecting the Rotterdam hydrogen cluster to other industrial clusters where hydrogen may be the preferred solution to decarbonize, like in Delfzijl/Eemshaven, Chemelot, the Ruhr area and Antwerp.

In Rotterdam, current natural gas consumption is at 117 PJ for the industry and 30 PJ for power production. In addition, there is 120 PJ of energy used in the form of residual gases[5].

Converting the above-mentioned natural gas and residual gas streams to hydrogen and removing the CO_2 could lead to a reduction in emissions by 12-15 Mt. Furthermore, hydrogen could also potentially be used to (help) decarbonize the two coal-fired power plants in Rotterdam.

In this annex, the market for hydrogen will be analysed in more detail.

Although currently the spotlight in the Netherlands is primarily on green hydrogen, up to 2030, the production capacity of green electricity available for producing hydrogen is expected to be limited. Moreover, in the long term, the projected offshore wind production on the North Sea may not be sufficient to meet the growing hydrogen demand of the future. Importing green

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[5] (page 8, (Rotterdam-Moerdijk Industry Cluster Work Group , 2018))

hydrogen is expected in the longer term to ensure adequate supply of green hydrogen on the market. The development both of an infrastructural backbone for hydrogen transport and of demand for blue hydrogen should pave the way for primarily green hydrogen imports in the future.

All parties agree that the final destination of a hydrogen value chain should be based on green hydrogen supply. As mentioned in the previous paragraph, future large-scale supplies of green hydrogen will need to be based on imports, and likely from far-away regions with abundant supplies of green and cheap energy. Although one of the challenges will be to transport such volumes safely and at acceptable cost levels, multiple studies are already exploring the transportation of hydrogen over long distances, using the following routes:

- Transport of Liquefied hydrogen (L-H_2)
- Transport using so-called hydrogen carriers, namely:
    - Liquid Organic Hydrogen Carriers (LOHC)
    - Ammonia (NH_3).

Transporting liquid hydrogen is comparable to transporting liquified natural gas (LNG), which is already commonplace. The main difference is that liquid hydrogen is substantially colder than LNG and evaporates more easily. Hydrogen can be liquified by cooling it to –252.87 degrees Celsius, after which it can be transported by ship or by train. This route is currently being investigated but will require large investments to develop a fully new worldwide supply chain.

In the LOHC process, the produced hydrogen is stored in an organic compound, called a carrier, via a hydrogenation step. This LOHC can then be transported, after which the hydrogen can be recovered from the carrier via a dehydrogenation step. The organic carrier can be reused without any CO_2 being emitted when the hydrogen is released. This transportation route is attractive since it offers a way to transport hydrogen by using mainly existing infrastructure, without large-scale infrastructural changes.

In the ammonia-based option, the produced hydrogen is combined with nitrogen to produce ammonia. After transportation, the hydrogen can be released from the ammonia via a catalytic process. Transporting ammonia requires well-known technology and offers a high hydrogen density transportation option while using existing infrastructure. Currently, ammonia is being used directly as feedstock for the chemical and fertilizer industry, and it is expected to be used in these high value applications first before becoming attractive and widely used as hydrogen carrier.

To summarise, each different import route for (green) hydrogen has its advantages and disadvantages. The choice between the different options will mainly depend on the extent to which the current infrastructure can be reused. Taking this into account, the import of hydrogen using carriers such as via LOHC technology is especially promising.

2.1.2 Defining the potential of blue hydrogen for industrial heat & power generation – assumptions, corrections and insights

In section 5.2 (blue hydrogen potential for H-vision) of the main report the potential of blue hydrogen for this project was discussed. In this Annex the assumptions and corrections used to determine the potential are explained.

Industrial heat demand

In contrast to domestic heat and power generation, industrial heat demand is foremost a baseload demand. It is ideally suited for H-vision as flexibility requirements are minimal and it will enable to maximize utilization of the H-vision hydrogen production assets.

Furthermore, a large part of the current industrial heat is produced through cogeneration units, which often have (partial) minimum utilization requirements. The power produced by "blue" Cogens will be CO_2-free or low-CO_2, and will contribute to the energy system of the future by providing both flexible and low-CO_2 regulating power.

Assumptions and corrections

The data from this report are interpreted and translated into a potential for heat demand in the industry, as is also discussed in Section 5.2 (blue hydrogen potential for H-vision) of the main report. Summarizing, the Davidse (Davidse Consultancy, 2012) data have been corrected for:

- Reduced/conservative potential in refinery gases for H-vision
- Including fuel for cogeneration power production (same fuel and stack)
- Generic eligibility correction
- Refinery gases

Several technical options are available for reducing CO_2 emissions of refinery fuel gases, which represent the largest part of the "residual gases" ("restgassen" in Dutch) in the Davidse report. Pre-combustion CCS and post-combustion CCS are available technologies and viable options. Some emissions might be very costly to reduce. Also, the impact on the total heat balance efficiency of a refinery needs to be considered.

In the Business as Usual scenario, the refinery gases potentially usable for H-vision are reduced by 70%; in other words, only 30% of the volumes are assumed to be "eligible" for H-vision. Other volumes will either present significant technical and/or financial difficulties, will be decarbonised by using post-combustion CSS or will have missed a crucial turn-around window.

It is also assumed that refinery fuel gases are for the most part used in traditional boilers and furnaces. The different scenarios; Economical World, Sustainable World, and Reference scenario (see Annex 1.3) are similar with respect to refinery gas options.

Include cogeneration power volumes

Cogeneration produces heat and power, whereas the Davidse study only calculates the heat energy produced/supplied. Using a generic efficiency, the fuel consumption is increased (assumed to be natural gas) to also include the fuel allocated to power production.

Industrial cogeneration is assumed to have a significant must-run component (compared to natural gas plants), so including these cogeneration volumes should bring positive value to H-vision.

Generic eligibility correction

After the correction for refinery gases and cogeneration power volumes, the total volumes amount to 126 PJ/j fuel consumption for industrial heat (and Cogen power). This is equivalent to a 4 GW perfect baseload offtake.

However, not all heat production units will be able to convert to blue hydrogen. Geographical, financial and technical factors will make it difficult to convert all heat production. However, the assumption is made that around 50% of the volumes will be convertible to H-vision. H-vision participants already represent a significant part of industrial heat demand/production and it is assumed that several other large industrial heat consumers will be interested to decarbonize their high temperature heat production.

Applying this 50% factor results in a heat demand of 63 PJ, equivalent to 2 GW perfect baseload consumption. This gives confidence to the second working group's (WP2) reference scope results (1,6 GW), even though WP2 included more refinery off-gas.

Technical conversion considerations

Conversion from natural gas and refinery fuel gases to blue hydrogen, will require furnace/boiler/cogen technical changes, which may have environmental (permit) impacts and which should be part of the individual plant financial assessment.

A short (non-definitive) list of technical site issues may be:

- Burner conversion
- Gas turbine conversion
- Emissions (NOx) changes
- Refinery gas suitability
- Operational effects (maximum/minimum load, ramping limitation, etc)
- Reliability impact

These technical considerations are not evaluated in detail in this study. They are assumed to be included in the applied corrections of 70% (for refinery gas correction) and of 50% (generic correction). Further detailed technical assessments will be required for the conversion of site units to blue hydrogen, which are covered in Chapter 6 (technology) of the main report and Annex 3 on technology.

Reliability requirements

Industrial clients require an extremely reliable heat supply. Furthermore, steam often has a safety function, as it can have a cooling effect in case of plant trips or may prevent plugging. Steam is also used to drive critical equipment such as air compressors. Steam/heat supply is more than a mere utility or commodity; reliability will therefore be a key aspect of any successful business case. A short supply interruption can lead to a lengthy stop and restart of plants, significantly amplifying the effects of these interruptions, especially as main industrial companies operate in clusters and are directly dependent on one another. Technical and environmental considerations may prevent dual/hybrid conversion: online and automatic switching between hydrogen and natural gas may not be possible.

Both reliability (number of interruptions) and availability (% uptime) are important. However, due to the nature of industrial processes, as described above, the number of interruptions could be considered even more important than availability.

At the very least, an N-2 design should be considered, as reliability during maintenance will need to be guaranteed. Some consumers/clients may be able to accept interruptibility in the form of imbalance (cogen/power sector), demand response or dual/hybrid firing, and may become a key contributor to system reliability and a healthy business case.

Power sector demand

Electricity sector model

The model used to calculate the dispatch of the power plants in Rotterdam which are part of the H-vision project is PPSGen (Power Price Scenario Generator) from the eRisk Group. A description of the model is included in Annex 2.4.

Scenario assumptions

Three distinct scenarios have been developed and four different technical configurations(scopes) were subsequently analysed under these scenario assumptions.

Hydrogen demand estimates for the different power plants result from a large number of assumptions, of which the most relevant are discussed below:

- Commodity prices
- Generation capacity developments
- Demand developments.

Commodity prices

The three commodity price scenarios are based on the World Energy Outlook 2018 of the IEA (International Energy Agency, 2018) and the (ECN, PBL, CBS & RVO, 2017) Nationale Energieverkenning 2017. The NEV 2017 was used as a source for biomass prices. Hydrogen prices are assumed to be set at a discount versus natural gas prices compensated for CO_2. The three scenarios are:

1. Business As Usual world (BAU)

   This is similar to the IEA Current Policy scenario. This scenario assumes that no new policies will be introduced. CO_2 prices are not expected to increase much further and gas prices do not increase much.

2. Economical World (ECON)

   This scenario is comparable to the Sustainable World scenario; however, a strong increase of natural gas prices is anticipated due to a booming economy. Contrary to the assumptions underlying the Sustainable World scenario, high CO_2 prices do not lead to lower demand for natural gas, leading to price hikes of natural gas.

3. Sustainable World (SUST)

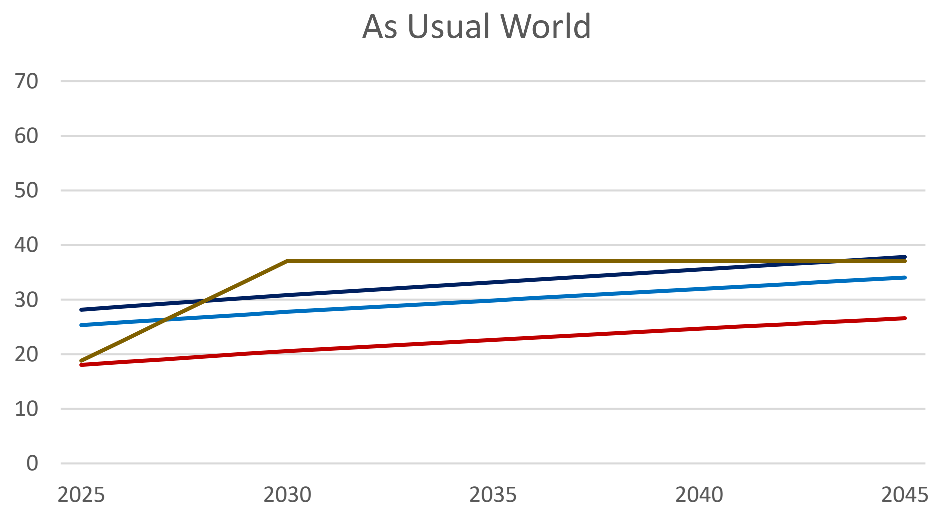
   This scenario is based on the IEA scenario which bears the same name. CO_2 prices are assumed to be pushed up in order to enable the investments needed to limit global temperature rise to 2°C. In this scenario, natural gas prices are assumed to be lower as a result of low demand.

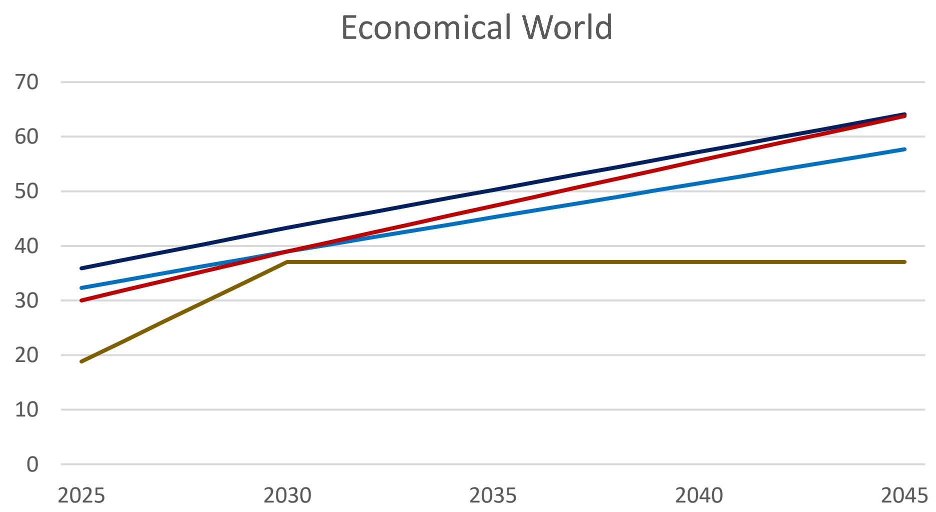
The focus of H-vision is on sensitivities versus CO_2 and natural gas prices.

Coal*:* IEA coal prices for the Current Policies and Sustainable World scenarios have been applied. In the Economical World scenario, coal prices of the Current Policies scenario are applied.

Biomass*:* Biomass prices are based on decreasing government incentives towards 2030, when they will be abolished. The Nationale Energieverkenning 2017 provides an analysis of the longer-term biomass prices which have been applied in all three scenarios.

In the graphs below (Figure 2.A), prices are plotted including costs for CO_2 compensation (in case of natural gas and coal use). Hydrogen prices are assumed to be 90% of CO_2 compensated natural gas prices as a result of government incentives.





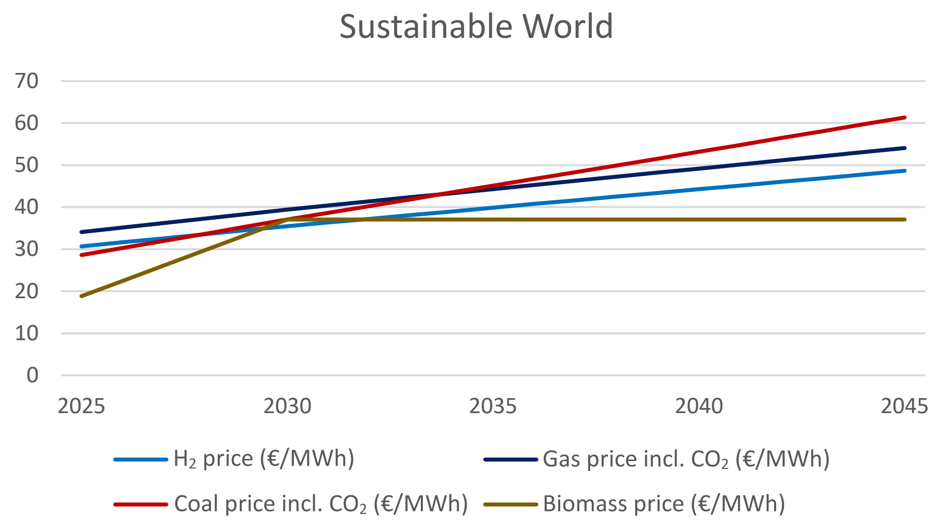


Figure 2.A: Scenario commodity prices

Power generation capacity developments

The focus of the H-vision study is on blue hydrogen applications in refineries and power plants. To fully understand the impact of market developments on the various power plant configurations, only one scenario has been applied to the development of power generation capacity. This scenario is based on known ambitions of governments in North-West Europe. In the Netherlands, it has been based on the discussions at the “Klimaattafels” aimed at a national Climate and Energy Agreement. In Germany, it has been based amongst others on what is known about the “Kolenausstieg”; in France, on announcements made by president Macron about the future of nuclear power plants. Renewable capacity developments are based on known plans in the various countries. The next graphs summarise the expected developments (Figure 2.B).

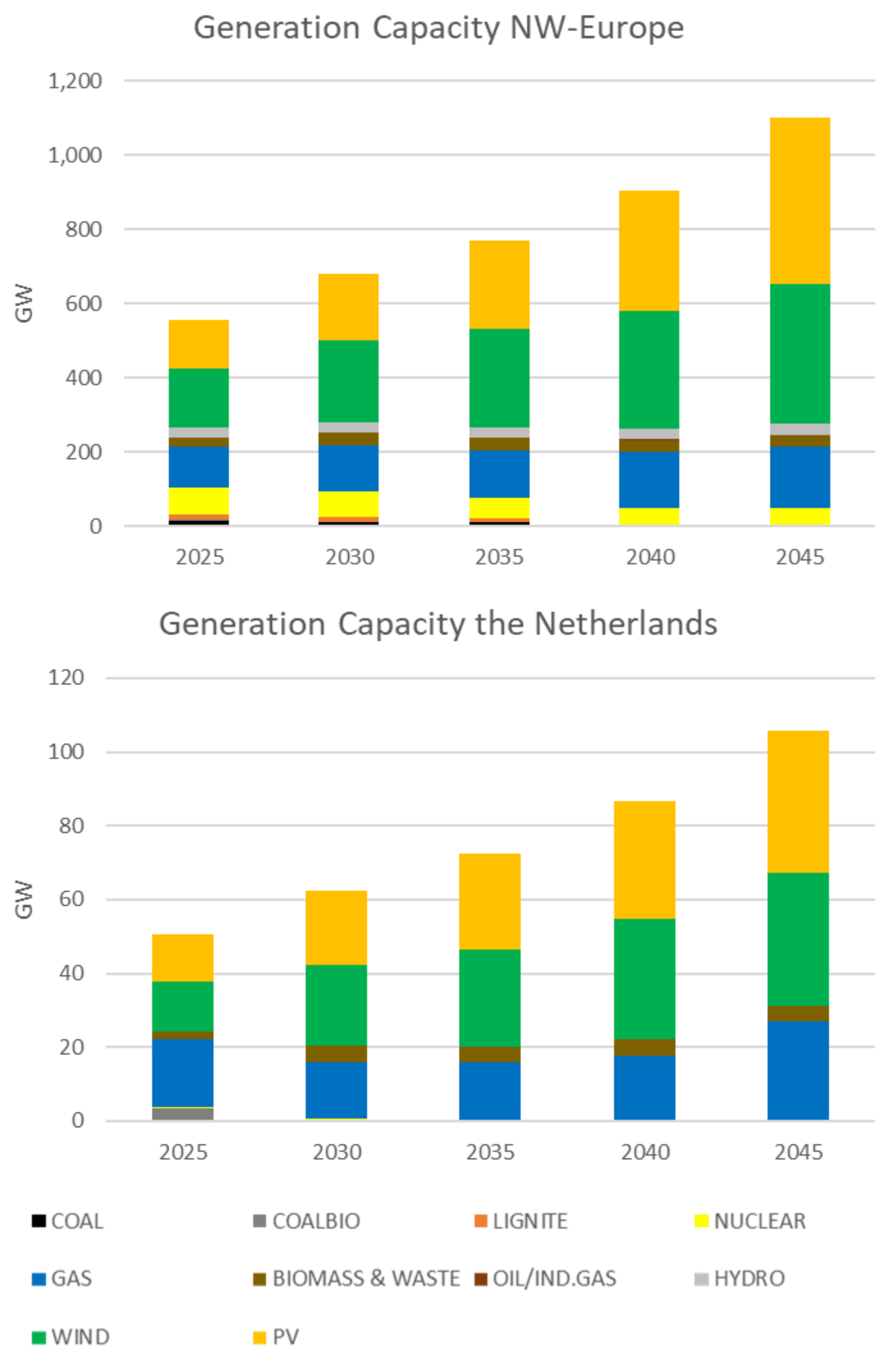


Figure 2.B: Prediction of future generation capacity in North-West Europe and the Netherlands

While fossil fuels and nuclear capacity are relatively stable (around 250 GW), nuclear, coal and lignite capacity is being replaced by natural gas capacity. Renewable capacity is growing spectacularly from over 300 GW in 2025 to almost 850 GW in 2045.

The Netherlands is one of the best-connected countries in Europe. Based on existing capacity and current plans, the assumption is that current cross-border capacity increases to around 11 GW in 2030.

Power demand developments

Electricity demand is expected to increase substantially. Three main factors impact electricity demand. On the one hand, continuous efficiency improvements lead to a declining power demand for current applications of approximately 1% per year. On the other hand, power demand is growing as a result of both economic growth (set at 1,5% per annum between now and 2045) and electrification of the energy demand. Especially transportation and low temperature heat are expected to run increasingly on electricity instead of fossil liquid fuels and natural gas. Figure 2.C illustrates the electrification of energy demand in the Netherlands. Assumptions around highly uncertain electrification of processes such as industrial heat production are also included. All assumptions are based on the "Klimaattafel" discussions. More details are available on request.

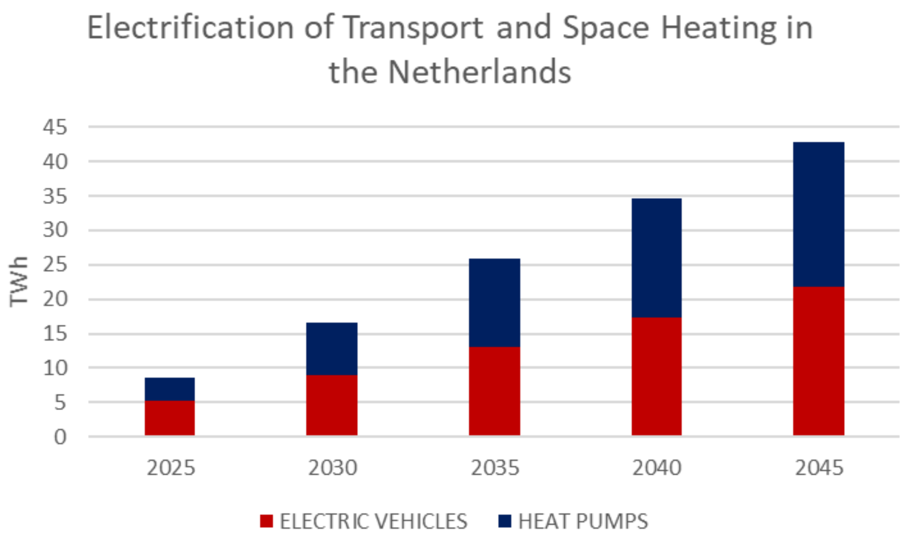


Figure 2.C: Prediction of future energy demand by electric vehicles and heat pumps

Hydrogen-fired power plant assumptions

We have developed three different technical configurations which are to be analysed in three market scenarios. In order to model the technical configurations, certain assumptions have been made regarding the power plants. Three existing power plants are included in this study. One is Pergen, a CHP(combined heat and power plant) in which cofiring of hydrogen is assumed (25%, 50% or 100%). The other two are coal-fired plants representing the two power plants in Rotterdam, owned by Engie and Uniper. Although the theoretical configurations of the plants described in the scenarios are not equal to the existing plants, for the purpose of this study, they are assumed to be representative. In a next phase, more detailed studies on the exact power plants need to be performed. Table 2.A provides the most relevant assumptions needed to simulate these power plants in a long-term dispatch model.

Pergen is a CHP. The assumption is that a percentage of the current fuel (natural gas) can be replaced by hydrogen. In the minimum and maximum scope, this percentage is set at 25%. In the reference scope at 50%. The percentage refers to the MWh replacement (not volume).

The two coal-fired power plants of respectively 800MW and 1070MW are assumed to be converted into biomass-fired plants with a capability to cofire a percentage of hydrogen. On top of that, gas turbines will be applied (exact technical configuration is explained in detail in

Chapter 6 (technology) of the main report and Annex 3 on technology). It is assumed that the gas turbine will rise from 10% to 100% use over a four-year period.

	Unit	2025	2026	2027	2028	2029	2030	2045
Minimum								
CHP								
Pergen co-firing H2	% of total plant	0%	25%	25%	25%	25%	25%	25%
ENGIE COAL	MW	800						
CoalBio	MW		640	640	640	640	640	640
Co-firing H2	MW		80	80	80	80	80	80
	% of total plant		10%	10%	10%	10%	10%	10%
Turbines H2	MW		0	0	0	0	0	0
UNIPER COAL	MW	1070						
CoalBio	MW		856	856	856	856	856	856
Co-firing H2	MW		107	107	107	107	107	107
	% of total plant		10%	10%	10%	10%	10%	10%
Turbines H2	MW		0	0	0	0	0	0
Reference								
CHP								
Pergen co-firing H2	% of total plant	0%	50%	50%	50%	50%	50%	50%
ENGIE COAL	MW	800						
CoalBio	MW		640	640	640	640	640	640
Co-firing H2	MW		0	0	0	0	0	0
	% of total plant		0%	0%	0%	0%	0%	0%
Turbines H2	MW			294	294	294	294	294
	% of total plant			10%	50%	75%	100%	100%
UNIPER COAL	MW	1070						
CoalBio	MW		856	856	856	856	856	856
Co-firing H2	MW		0	0	0	0	0	0
	% of total plant		0%	0%	0%	0%	0%	0%
Turbines H2	MW			294	294	294	294	294
	% of total plant			10%	50%	75%	100%	100%
Maximum								
CHP								
Pergen co-firing H2	% of total plant	0%	100%	100%	100%	100%	100%	100%
ENGIE COAL	MW	800						
CoalBio	MW		640	640	640	640	640	640
Co-firing H2	MW		96	96	96	96	96	96
	% of total plant		15%	15%	15%	15%	15%	15%
Turbines H2	MW			294	294	294	294	294
	% of total plant			10%	50%	75%	100%	100%
UNIPER COAL	MW	1070						
CoalBio	MW		856	856	856	856	856	856
Co-firing H2	MW		128	128	128	128	128	128
	% of total plant		15%	15%	15%	15%	15%	15%
Turbines H2	MW			294	294	294	294	294
	% of total plant			10%	50%	75%	100%	100%

Table 2.A: Configurations for the power plants considered in the study

Electricity model results

The electricity model has been used to simulate the electricity market for the described scenarios. This section first renders the results in general terms: how is the future production mix expected to develop in the Netherlands and what is the trend in CO_2 emissions. Next electricity price developments are given; understanding them is required in order to understand the response of the power plants that could use hydrogen from the H-vision project, which is shown in the following section. Finally, total hydrogen demand from the Rotterdam power sector is shown for the different scenarios and development concepts.

Overall – Generation volumes and CO_2 emissions

Figure 2.D shows the production mix development in the Netherlands for three different scenarios. The installed capacities of generation technologies are assumed equal in all scenarios. Therefore, the production of wind and solar is equal in all scenarios and increases over the period until 2045. The other technologies compete based on fuel and CO_2 costs, and as costs assumptions between the scenarios vary, the amount of generation per technology varies.

In all scenarios, the use of coal stops from 2030 onwards due to the coal ban. Its role is largely taken over by gas. The largest difference between the scenarios lays in the role of biomass versus the role of gas. In the As Usual World, the result of the price assumptions is that a gas-fired plant is cheaper than a biomass-fired plant. In the other two scenarios, a gas-fired plant (including CO_2 costs) is more expensive to operate than a biomass-fired plant, which means that biomass plants will be high in the merit order and have more running hours.

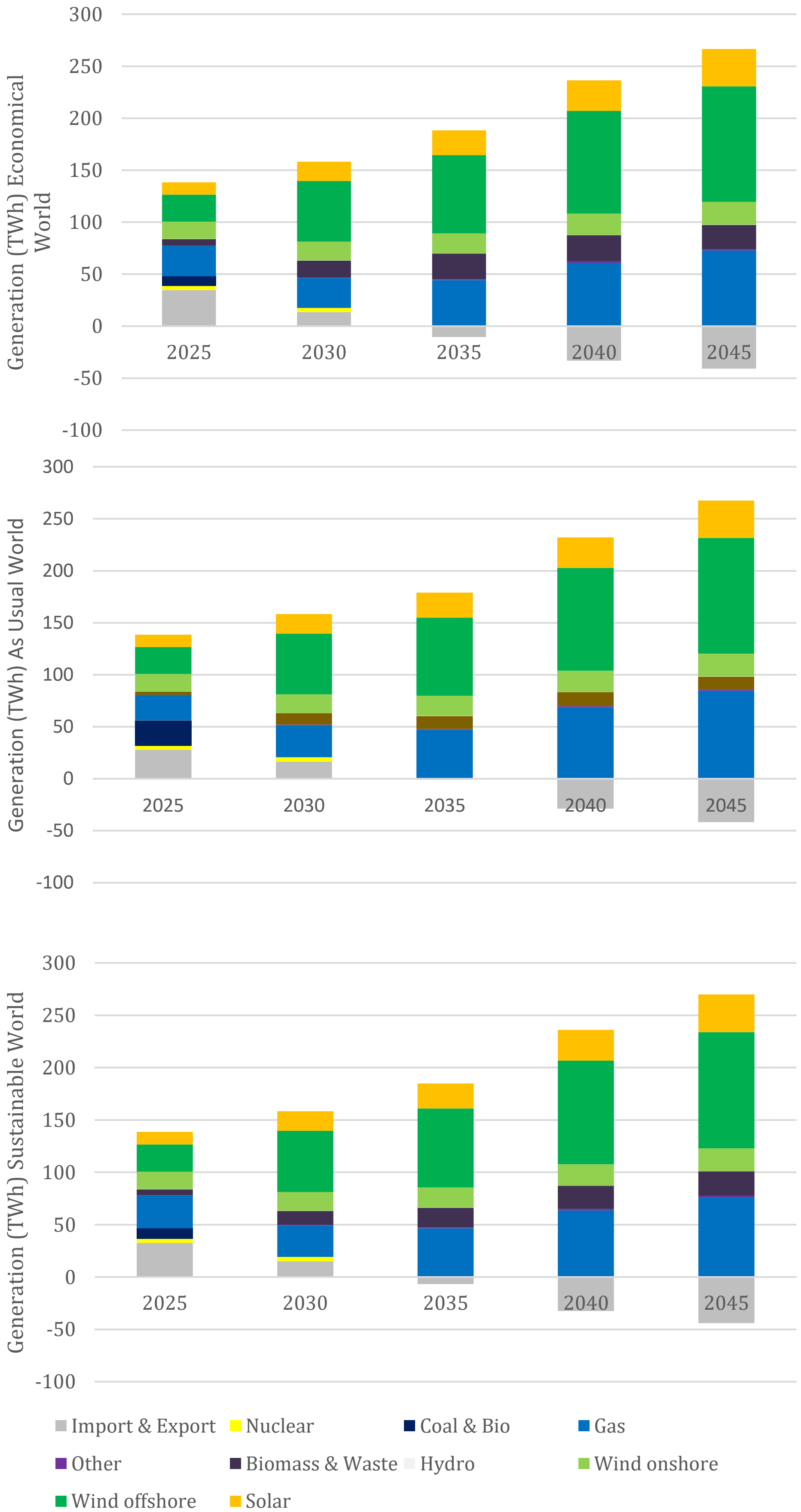


Figure 2.D: Prediction of future electricity generation in the Netherlands for different scenarios

Figure 2.E displays the development of the CO_2 emissions for the Dutch power sector. The coal phase-out significantly decreases national greenhouse gas emissions between 2025 to 2030. However, due to increased power demand, which is largely met by gas-fired power plants, CO_2 emissions go up in the period after 2030. The CO_2 emissions per kWh produced remains largely stable between 2030 and 2045 in all scenarios. As CO_2 prices are lower in the As Usual World scenario, biomass plants run at lower levels, and gas-powered plants run at higher levels, leading to more CO_2 emissions. It is important to remember that the results in Figure 2.E are only valid for the assumed price developments, which means that the Netherlands starts exporting electricity (instead of importing electricity as is currently the case) and no other policies are implemented that change the price of CO_2 emissions or prohibit certain fuels.

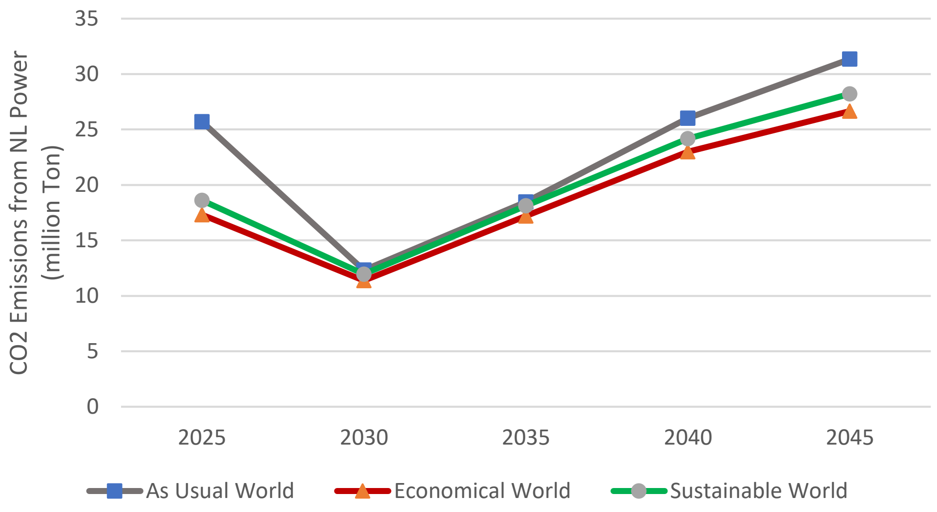


Figure 2.E: Model results for the CO_2 emissions in the power sector

Gas-fired power plant Pergen

Figure 2.F shows the production in the no development scope. The production of Pergen is largely stable over the years but drops slightly from 2028 to 2031 in all price scenarios. Although not depicted, the generation volumes remain stable until 2045.

The price scenarios (As Usual World,(BAU) Economical World(ECON) and Sustainable World(SUST)) do not significantly influence the operation of the Pergen gas fired CHP. The difference between the 3 scenarios is in the gas and CO_2 prices, which influence the absolute costs of the Pergen plant, but not the costs relative to other (gas) plants in the Netherlands. This leads to the fact that Pergen's position in the merit order remains unchanged, and the plant's yearly operational profile remains largely unchanged.

Figure 2.G displays what happens if hydrogen from the H-Vision project is mixed into Pergen's fuel, from 2025 onwards 25% of hydrogen is mixed through the natural gas (BAU). As the hydrogen is assumed cheaper (based on subsidies) than natural gas including the CO_2 costs, the total production costs of the plant go down. Lower costs compared to other plants lead to (total) higher production volumes.

also provides the hydrogen generation numbers for the maximum scope under the Economical and Sustainable Worlds.

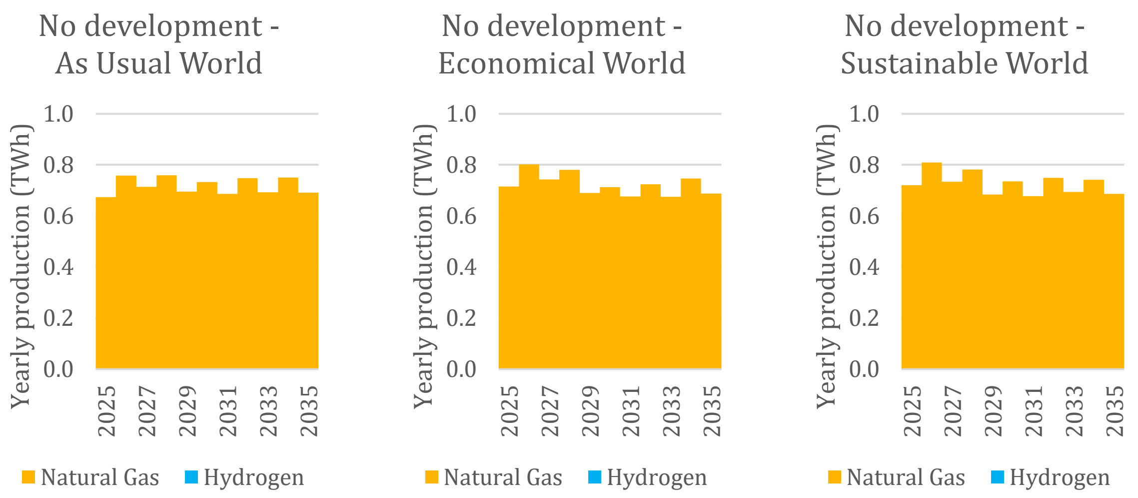


Figure 2.F: Electricity production of Pergen in the no development scope/As Usual World (left), no development scope/Economical World (centre) & no development scope/Sustainable World (right)

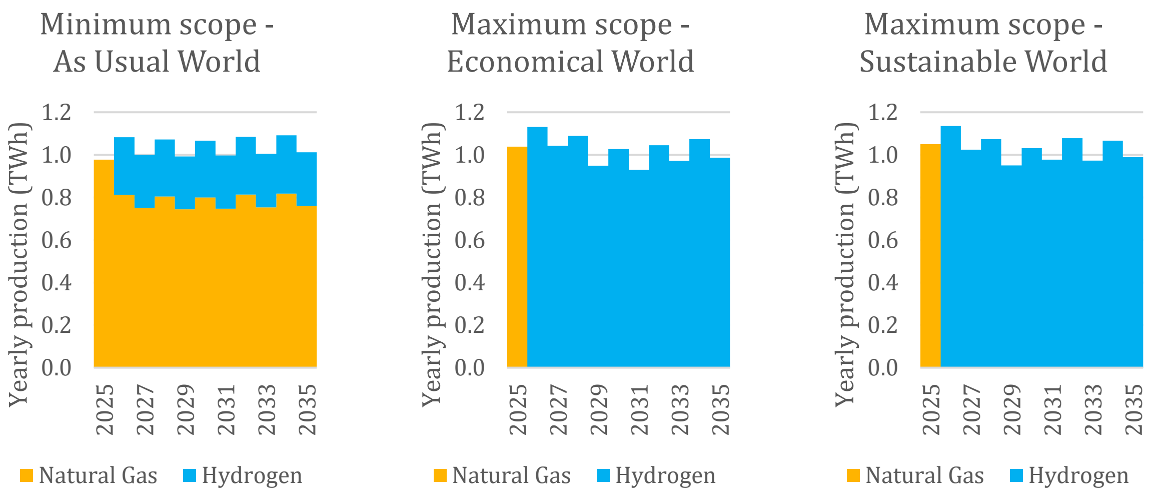


Figure 2.G: Electricity production of Pergen in the minimum scope/As Usual World (left), maximum scope/Economical World (centre) & maximum scope/Sustainable World (right)

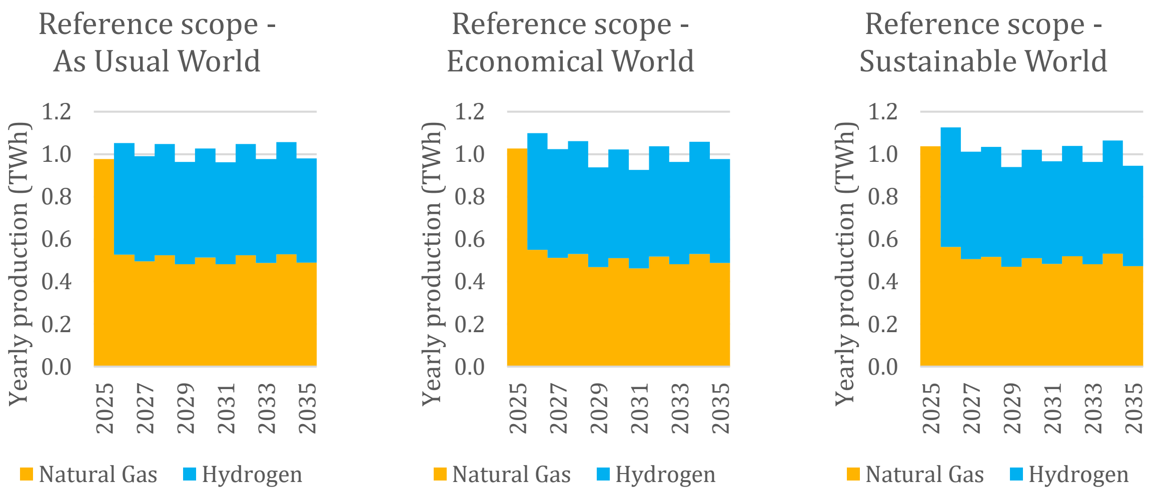


Figure 2.H: Electricity production of Pergen in the reference scope/As Usual World (left), reference scope/Economical World (centre) & reference scope/Sustainable World (right)

Finally, Figure 2.H shows the hydrogen versus natural gas mix in the reference scope case. In those cases, 50% of hydrogen is included in the power plant's fuel mix. The same effect as in the minimum development case is observed, the lower costs of hydrogen lead to a higher total production volume for Pergen.

Coal-fired power plants

For the no development scope, the combined production volume of the Rotterdam based coal-fired plants can be seen in Figure 2.I. In the no development scope, H-vision is not realised and hydrogen is not used in the coal plants. Due to increasing CO_2 prices and increasing infeed from renewable sources, production volumes go down in the period until 2030. In 2030, coal plants are not allowed to use coal anymore and could switch to biomass. Due to the assumptions about the gas and CO_2 price, and the fact that the costs for conversion of the coal power plants to biomass are not included in the study, biomass is a competitive option in all scenarios.. The

ECON scenario assumes the highest prices for both gas and CO_2 which means the attractiveness of biomass increases even further until 2040, when they essentially become baseload plants. See Text box 1 for more information.

Text box 1: Biomass in coal-fired power plants

The future behaviour of the coal-fired plants, and whether biomass is an attractive alternative after the coals ban is highly dependent on the prices of biomass on the one hand and gas and CO_2 on the other hand. A relatively low biomass price compared to the gas and CO_2 prices makes biomass an economically attractive alternative. The model that is used in this study will automatically select biomass as a viable option. However, when this tipping point is reached in real life, the demand for biomass will increase drastically, which will in turn increase the price of biomass, making it less attractive again. Such real-world effects are not included in the model, therefore, no conclusions about the future feasibility of biomass in coal-fired power plants can be drawn from this study. The presented results are only ´possible futures developments´.

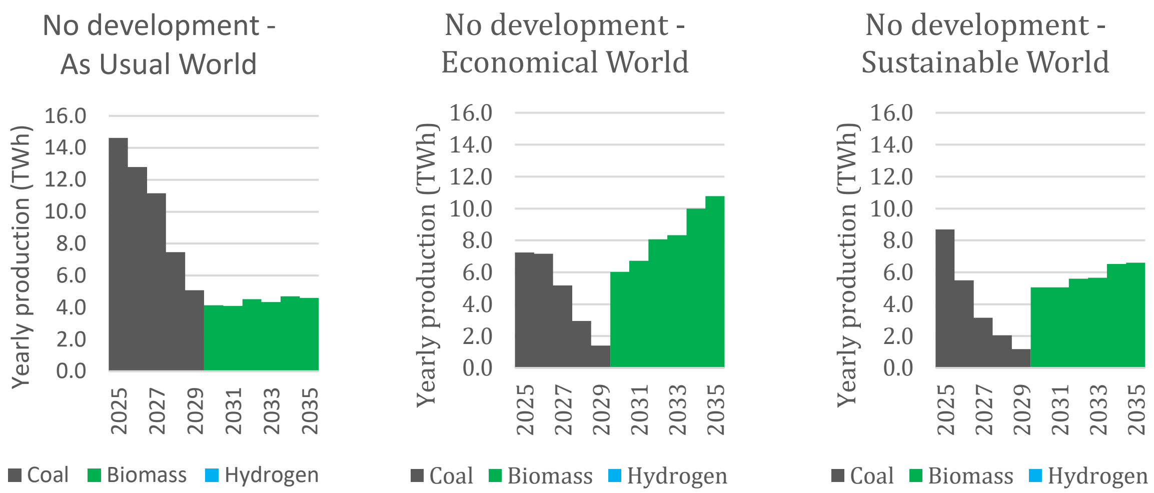


Figure 2.I: Electricity production of coal/biomass power plants in the no development scope/As Usual World (left), no development scope/Economical World (centre) & no development scope/Sustainable World (right)

Figure 2.J and Figure 2.K show what happens with the coal-fired power plants generation volumes if the H-vision project is developed, respectively in the minimum scope, reference scope and maximum scope. In all cases, the use of coal stops in 2025 and the power plants are converted to biomass-fired plants. Furthermore, the coal-fired plants steam circuits are deeply integrated with the neighbouring hydrogen production unit(s).

The minimum scope (Figure 2.J left) assumes hydrogen use in the coal plants' pre-heaters, which represents a rather low volume of hydrogen compared to the use of biomass. The amount of production is dependent on the price scenario, but is generally higher than in the reference scope (where no hydrogen is added). This is caused by the fact that the plants need to stay at minimum load due to the deep integration of the steam circuits of the power plants and the hydrogen production unit(s), this leads to a 'must run' situation, increasing the plants operational hours and production. The difference between the price scenarios is caused by the price of biomass compared to the prices of gas and CO_2.

In the reference scope development concept (Figure 2.K) two hydrogen-fired gas turbines are integrated into the existing coal plants which slowly start their operation in 2027, until reaching their maximum capacity in 2030. The new gas turbines in combination with the must run situation ensure a high use of hydrogen.

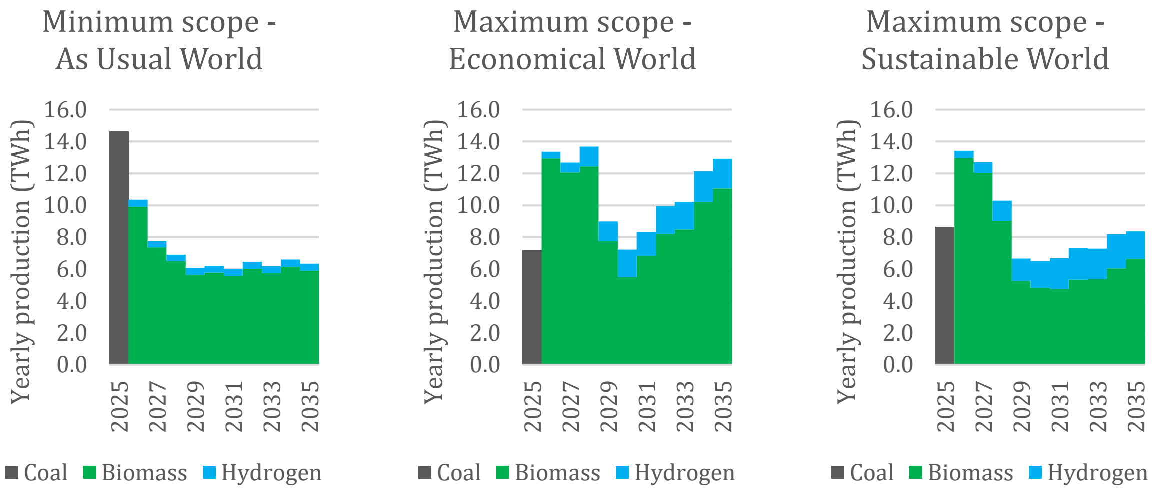


Figure 2.J: Electricity production of coal/biomass power plants in the minimum scope/As Usual World (left), maximum scope/Economical World (centre) & maximum scope/Sustainable World (right)

The maximum hydrogen development situation (Figure 2.J centre and right) combines the two technological concepts of hydrogen-preheating and hydrogen gas turbines, increasing the use of hydrogen even further.

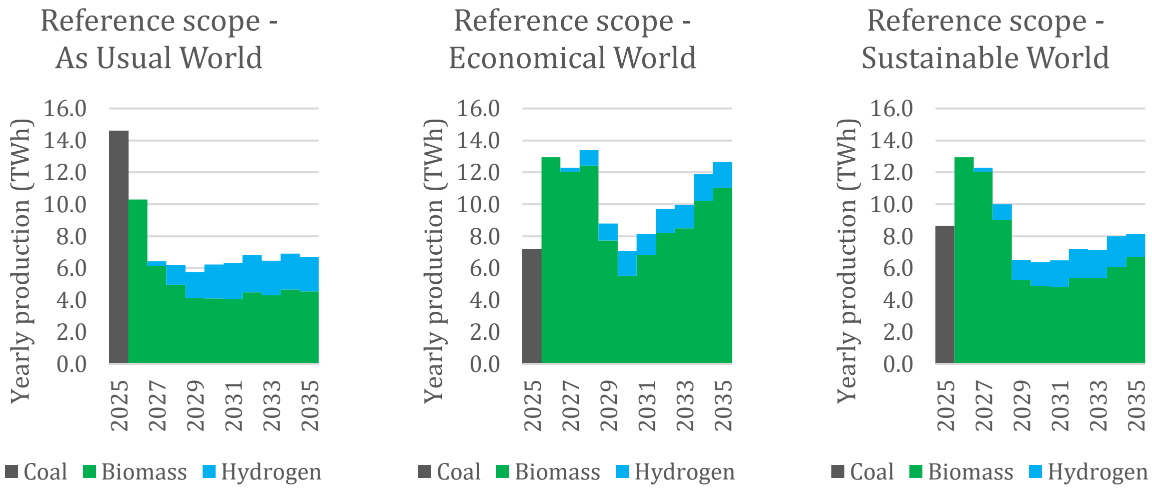


Figure 2.K: Electricity production of coal/biomass power plants in the reference scope/As Usual World (left), reference scope/Economical World (centre) & reference scope/Sustainable World (right)

Fluctuations in hydrogen demand from power plants can be substantial. The next graphs (Figure 2.L) illustrate the total hydrogen demand over all powerplants in 2030 for each scenario and scope evaluated. The lowest demand, the highest demand and the average demand per day are displayed.

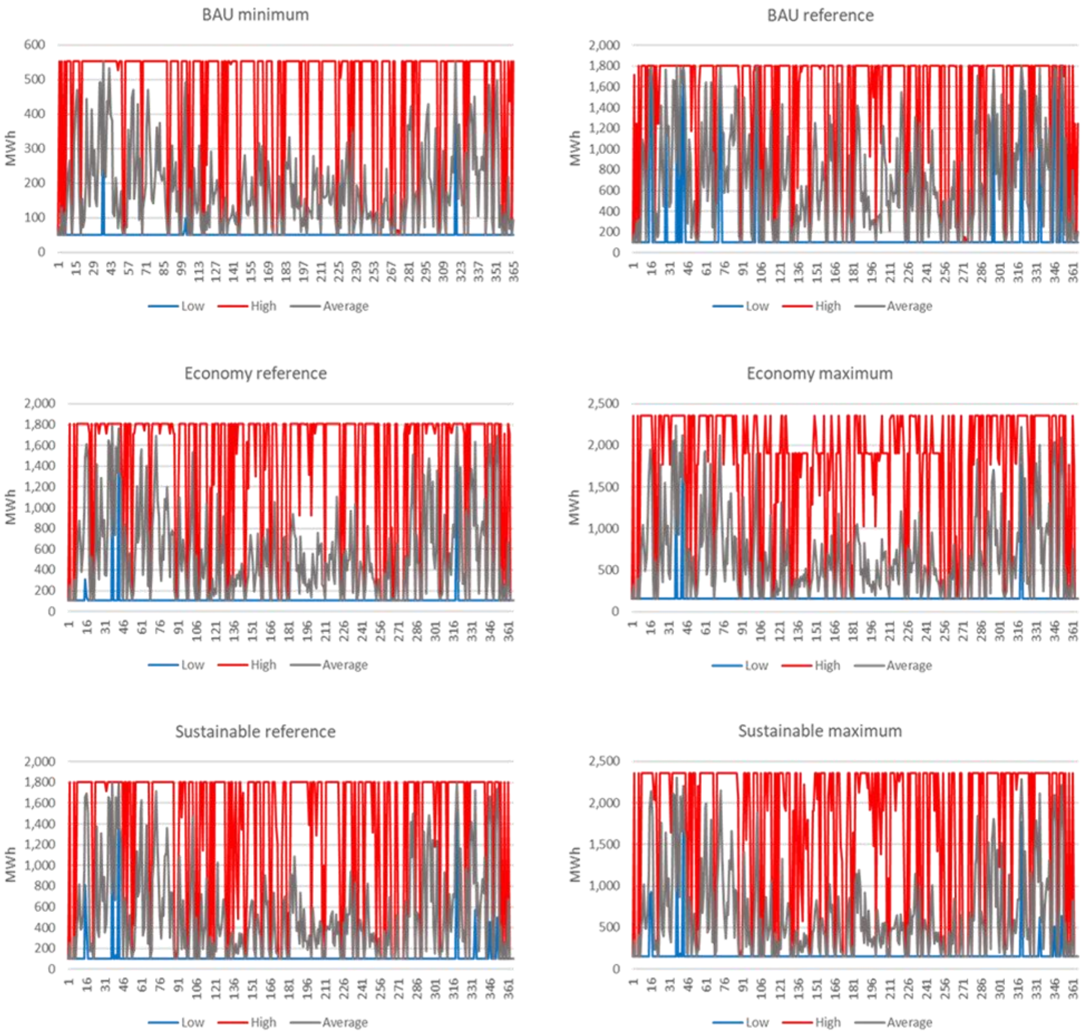


Figure 2.L: Total hydrogen demand evaluated for all powerplants in 2030 for each scenario (BAU [As Usual World], Economy [Economical World] and Sustainable [Sustainable World]) and development scope (minimum, reference and maximum). Blue line is lowest demand, grey line is average demand and red is highest demand

Depending on the flexibility of the hydrogen production facilities and the flexibility in other demand processes, more or less storage is required to make optimum use of the flexibility these powerplants can generate.

2.1.3 Market for hydrogen as feedstock

The market for hydrogen as feedstock is not a focus market for H-vision and is not part of the scope of the study. This is due to the fact that:

- The current feedstock market is established and demand can be met by current assets
- The current feedstock market will be significantly decarbonized with the help of the Porthos project, Porthos being a prerequisite for H-vision
- In future, additional demand to the current market for blue hydrogen feedstock is unclear and is expected to be low for quite some time.

Feedstock quality (~99.95%) is significantly higher than caloric quality (95%) and requires additional process steps. These increase CAPEX and OPEX costs and therefore increase the required support and/or cost of the end-product.

In 2035-2040, should there be a significant new market in feedstock-quality blue and/or green hydrogen, H-vision assets should be expanded (future add-on option) at that time to produce feedstock quality hydrogen, provided sufficient plot space is available.

Although it was not within the direct focus of the H-vision study, OCI Nitrogen has evaluated some of the options for fuel-grade hydrogen within a large-scale feedstock application: the production of ammonia.

2.2 Typical development steps of a successful hub

2.2.1 Commercial Framework development: from bilateral investment-related commercial agreements to wholesale commodity trading

As mentioned, there is an established hydrogen market, in which hydrogen is being used as a feedstock and primarily produced through the reforming of natural gas. A limited number of producers is selling this hydrogen to a limited number of consumers via bespoke bilateral contractual arrangements. In the Netherlands, the pricing of hydrogen is being done via net-back gas and oil formulas in isolated transportation systems, mainly in the Rotterdam area.

In order to develop a large-scale hydrogen value chain, large investments are required: hydrogen production facilities (electrolysis capacity), hydrogen infrastructure, storage facilities, end-user applications. To ensure the right investments, commercial frameworks need to be set up that are similar to those currently in practice: longer term bespoke bilateral contractual agreements. However, once the market develops further and matures, it will be necessary to move to frameworks that are used for commodity wholesale trading. The next paragraphs describe which steps typically need to be taken and which developments need to take place to allow for a successful development towards a mature hydrogen market.

2.2.2 How to develop a successful trading hub for hydrogen

Mature trading hubs are generally characterised by good liquidity, high volumes, multiple suppliers and users, and they can show high volatility. Often, they are a price-benchmark as well as a market place, reflective of supply and demand; they are a physical transfer-point while also attracting ‘speculative’ trading.

Open and transparent markets facilitate trading and in time guarantee transparent and trustworthy prices, since the market depth and the bid-offer spread facilitate this at all time. They attract many different types of participants that bring liquidity to the market. Liquid markets enable to physically adjust portfolio volumes over time and to manage the financial risks of commodity portfolios. Mature commodity markets can provide security of supply. Above all, they provide secure risk management tools.

Development path

When establishing a successful commodity trading hub, its development path typically follows a number of different steps:

- Third parties are granted access to the infrastructure

  Parties –besides the owner(s)/operator(s) of the infrastructure – are granted access to this infrastructure. Typically, a portion of the total capacity is auctioned through open seasons/auctions for multiple years.

- Bi-lateral trading starts taking place

  Multiple parties now have access to the infrastructure and can use the infrastructure for the transportation and/or storage of the commodity. Parties will start transacting volumes mainly from a physical risk-managerial background.

- Price discovery and price disclosure will occur

  The more transactions, the more the need for reliable and tradeable prices will occur. Price discoveries will take place via parties with a commercial interest in doing this.

- Balancing rules and standardised trading contracts are drawn up

  The need for a TSO-like function will arise. Parties will –from a physical portfolio balancing perspective– feel the need for such a function. Also, as the traded volumes rise, parties will want to align the contractual terms used for these transactions, hence the need for standardised trading terms/contracts.

- OTC-brokered trading comes into effect

  Parties are now trading with multiple counterparts throughout the curve and major international brokerage firms will start to trade these products.

- More non-physical players enter the market

  With tightening bid-offer spreads and growing liquidity throughout the curve, non-physical parties enter the market for conducting non-risk managerial transactions.

- Futures exchanges will start offering cleared and financially settled products

  Exchanges have been monitoring developments for a while and with constantly growing liquidity, exchanges will enter the market.

- Establishment of a liquid forward curve

  Standardised and harmonised products are being traded via both (multiple) brokers and exchanges, which will lead to a heavily traded and liquid forward curve.

- The traded market indices will be used as benchmarks for long-term contracts

  Exchanges and reporting agencies will report various liquid and established indices, which are being used as benchmarks in long-term delivery contracts.

2.2.3 Evaluation criteria identifying the status of a trading hub

In order to evaluate the success of the trading hub, typically the following indicators can be analysed:

1. Market participants

   In a well-functioning market, there will be a substantial number of counterparts, ideally with varying portfolio requirements and hedging strategies such as producers, consumers, (multi commodity) traders and market makers.

Challenge for hydrogen: local markets, direct relation/contract single buyer/seller, current lack of “market-development-desire”.

2. Traded products

   In an established commodity trading market, there is a suite of products with maturities varying from WD to multiple years out (Y+4, Y+5), all with standard and harmonised terms, often both physically and financially settled (especially the products further on the curve).

Challenge for hydrogen: varying qualities, green/blue/grey/black hydrogen, pricing/administration/ operational/certificates issues.

3. Traded volumes

   The larger, established trading companies have standardised risk management rules and need a certain open interest in products to be able to trade in these products. The more products on the curve being above this risk management threshold, the more liquid these products will be.

Challenge hydrogen: reaching a minimum traded volume threshold, where risk managers get comfort using the market/commodity for risk management/hedging purposes.

4. Churn rates

   A measurement tool for how often a commodity is traded – the total traded volume / the physically traded volume. Generally, the idea is accepted that the higher the churn rate is, the more liquid a market is considered to be.

Challenge for hydrogen: currently, hydrogen is a pure physical commodity, hence the churn is (close to) one.

2.2.4 Success factors of North-West European gas hubs (TTF/NBP)

When looking at the rather successful development of the wholesale natural gas trading market in the Netherlands (TTF), one might consider the following elements as contributing factors to this success:

Trading contracts (EFET standard) with standardised terms. Only one set of standard contract-terms is widely used throughout the market by all market parties. Important terms to standardise/harmonise, are:

- Payment clauses
- Delivery terms
- Force majeure
- Netting arrangements
- Default arrangements.

Traded products specifications (respected by all brokers & exchanges). All brokers and exchanges have the same set of specs for all products. So a January contract on TTF can be traded via all brokers and exchanges by all counterparties without any discussion on the specs, as these are known and established.

TSO rules are also a rather critical set of rules. Ideally these rules are market/trading friendly and as much as possible in line with balancing regimes in neighbouring relevant and liquid markets. Important terms to align here, are:

- Nomination (lead) times
    - Virtual trading hubs instead of physical hubs or virtual/physical hub alongside
    - Balancing regime; ideally daily (EoD) balancing (NBP)

Large diversity of (various types of) market players. As mentioned earlier, in any trading market, it is key that different players, with different trading strategies meet each other when transacting. Only then can a market can become really liquid and deep. At TTF especially the following type of players are active and part of the success:

- Big natural gas producers
- Big natural gas consumers (utilities (with gas-fueled power portfolio), big industrials, parties with large household portfolio's)
- Traders (big vertically integrated players, banks, (Swiss) multi-commodity/global presence trading houses), some of them acting as market makers and/or liquidity providers.

Multi-commodity players. Especially in the second wave of the development of TTF, the vertically integrated, multi-commodity and globally present trading houses really brought additional liquidity and deepened the market. Also, continuous offering of multiple products helps create trust next to using TTF as delivery point for contracts.

- Large number of multi-commodity players with intra-commodity hedging strategy
    - Prerequisite: liquid spark- (gas vs power), dark- (coal vs power) & clean dark- (coal vs power (including CO_2)) spread trading.

Internal market. TTF is part of a larger, well-connected European gas market. The local markets are all connected through cross border transportation assets and all relevant markets are well provided with (both seasonal and short-cycle) storages.

- Connectivity between local markets
    - Sufficient cross border capacity between key markets (BBL/IUK)
    - Capacity auctions transparent and easily accessible

Diversity of supply. Finally, the natural gas molecules are coming from a wide range of sources, countries and companies.

- Own production (UK, Germany, the Netherlands)
- LNG terminals
- Interconnecting pipelines from producer to market
- Multiple pipelines between producing fields Norway -> UK/Germany/Belgium
- Delivery pipelines from Russia -> Germany (Nordstream (II))

2.3 Feedstock: OCI Nitrogen Case

The largest demand for hydrogen in the Netherlands is from the production of ammonia. At OCI Nitrogen in Geleen and at Yara in Sluiskil, the joint production of ammonia is about 2,5 million tons per annum. This requires around 450 ktpa of hydrogen. Next to the production, there is also a limited import of ammonia, via Rotterdam and Sluiskil, of around 250 ktpa. Combined, the total ammonia throughput in the Netherlands would account for about 500 ktpa of hydrogen .

The hydrogen for ammonia is produced in dedicated SMRs. These SMRs produce a mixture of hydrogen and nitrogen in the 3:1 molar ratio required for ammonia. Other components are not allowed or preferred as for example oxygen containing components (e.g. H_2O or CO_2) will poison the ammonia catalyst and inerts (e.g. Ar or CH_4) will reduce the efficiency of the reaction.
The hydrogen/nitrogen mixture from the SMR is pressurized to about 200 bars where it reacts to ammonia at 400-500°C. These conditions make it difficult to start and stop the process.

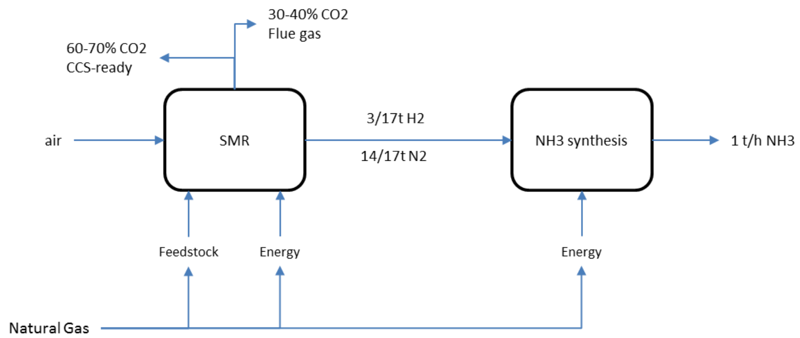


Figure 2.M: Schematic of ammonia production using Steam Methane Reforming (SMR) to produce hydrogen

Hydrogen from a H-vision plant could be used in ammonia production in various options:

1. Fuel (Energy) for the existing SMRs
2. Feedstock for the ammonia synthesis
3. Balancing the hydrogen grid with flexible ammonia production

As the current ammonia production facilities are not located in the Rotterdam area, these options would require investments in new production facilities in Rotterdam or in pipelines to Geleen or Sluiskil.

2.3.1 Option 1: Fuel for the existing SMRs

Current SMRs for ammonia capture only about 60-70% of the CO_2 that is produced as all the process gases are captured and the flue gases are emitted. Combining ammonia with CCS could be a logical next step. The flue gas could be decarbonized by using hydrogen from H-Vision. Consumption of hydrogen for fuel would be around 400MW in Geleen and around 600MW in Sluiskil. Although significant, these consumptions will most likely not be sufficient to justify the investment in a hydrogen pipeline from Rotterdam to existing plants. There will most likely be other consumers closer to Rotterdam that offer similar prices but within a shorter distance.

It is not logical to build new SMR's in the Rotterdam area to produced feedstock grade hydrogen using the hydrogen from H-vision as fuel. In that case, the design of (one of) the H-vision units should be modified in order to produce feedstock grade hydrogen (option 2).

2.3.2 Option 2: Feedstock for the ammonia synthesis

The ammonia synthesis section of an ammonia plant can be fed with a mixture of hydrogen and nitrogen. This hydrogen should have a tight specification regarding composition, which does not fit with the spec from H-vision. In order to use H-vision hydrogen for ammonia, an additional purification step is required. This purification will give a purge stream which is rich in methane and CO_2. Due to the energy in the methane a relatively large share of the energy content of the hydrogen stream is purged. The purge stream needs to be fired in a furnace or ideally this stream is returned to the H-vision installation. The required nitrogen could originate from the air separation unit that is built for the oxygen supply to H-vision's ATR.

The large hydrogen volumes in ammonia could be sufficient to install new pipelines to Geleen or Sluiskil. Then it is not possible to recycle the purge stream to H-Vision and/or find synergy with nitrogen consumption.

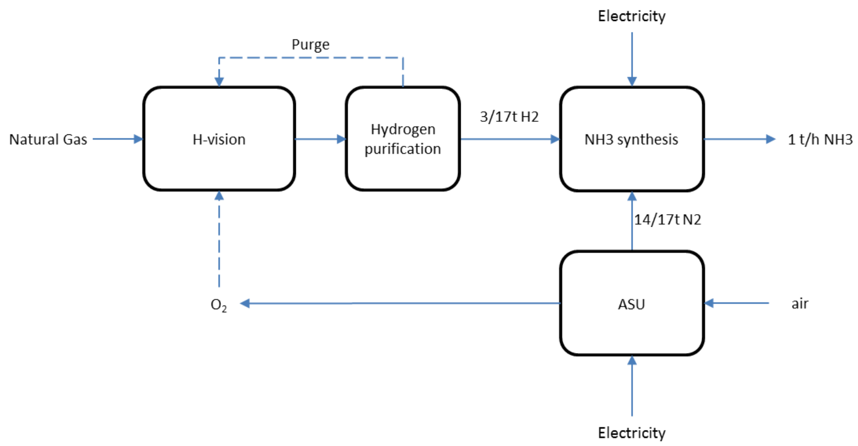


Figure 2.N: Schematic of ammonia production using hydrogen produced by a H-vision blue hydrogen plant

It would make more sense to build a new ammonia synthesis plant in Rotterdam close to the H-Vision plant. This would require significant investments (several 100's of million Euros) depending on the size. Building a new ammonia plant in Rotterdam would create some logistical issues as the governmental policy is to minimize the transportation of ammonia due to its toxicity. When only replacing the current import at OCI's terminal in Rotterdam, the hydrogen consumption of the ammonia plant would be relatively small.

2.3.3 Option 3: Balancing the hydrogen grid with flexible ammonia production

When a new ammonia plant is built in Rotterdam which is properly designed, such a unit can also deliver flexibility to the hydrogen consumption (e.g. an operating range of 25-100%). Then the ammonia production could be reduced to minimum capacity when power plants are running on hydrogen. When the electricity sector is not consuming hydrogen, the ammonia will run at

100%. The produced ammonia is then stored in large storage tanks and shipped to current consumers of ammonia.

The value of this flexibility should cover the investment costs of an installation with a low number of full load hours and the investment in storage. This could be an alternative for a larger H-vision unit or the storage of hydrogen in salt caverns. In a future case the ammonia could even

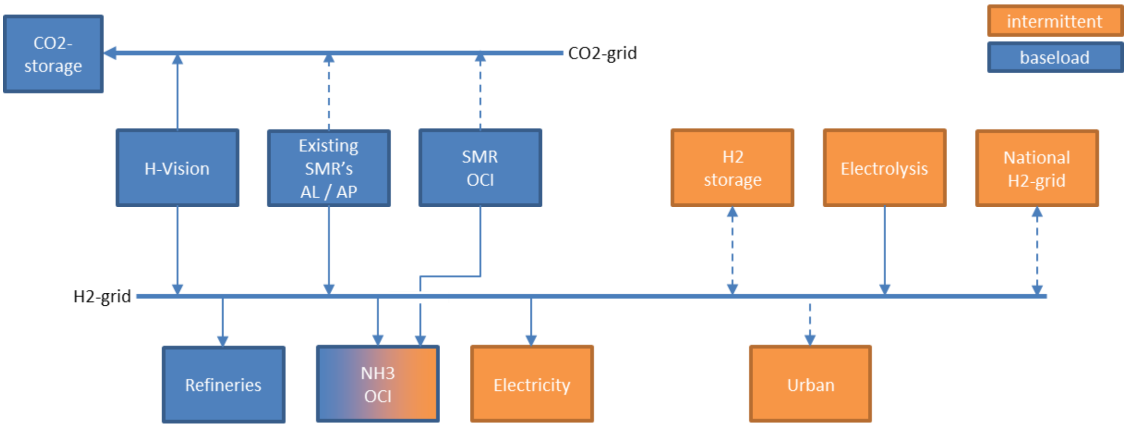


Figure 2.0: Schematic of hydrogen grid balancing using flexible ammonia production

be used as a storage for energy. In that case the ammonia is reformed into hydrogen and nitrogen when the hydrogen is required. The energy losses in each step will lead to a significant increase in primary energy consumption. As H-vision hydrogen is not fully decarbonized, the overall reduction in CO_2 emission is limited. The alternative, producing electricity from natural gas will be competitive up to relatively high CO_2 prices.

2.4 Power market model

The model used to calculate the dispatch of the powerplants in Rotterdam which are part of the H-vision project is PPSGen (Power Price Scenario Generator) from the eRisk Group.

PPSGen is a flexible and transparent merit order model of the North West European electricity market[6] which can be used for multiple analyses, including the impact of market changes and regulation on prices, portfolio value, and power plant dispatch. PPSGen focusses on specific countries in North-West Europe as the core region. Other neighbouring countries are included as non-core regions. This differentiation allows to model the power plants of the core-region on a very detailed (unit-based) basis, while power exchanges with other regions are included in the model at a lower level of detail. The core region is the Netherlands, Germany, Belgium, Luxembourg, France, and Great-Britain. Cross-border flows with countries outside the core region are modelled in accordance with their known available capacity and historical behaviour.

PPSGen consists of several input components (see Figure 2.P) which are used in a sequential order to perform calculations. First the demand parameters and assumptions per scenario are used to calculate the hourly demand load profiles including the dispatch of some of the flexible assets, such as domestic heat pumps. The hourly demand load profiles, the supply parameters and assumptions per scenario are the database and together with all individual powerplants and other flexible assets such as pump storage act as input for PPSGen to calculate hourly dispatch and prices of power plants per hour per year and per country.

A more detailed description is available on request.

[6] The North West European market is defined as Germany, France, Great Britain, Luxembourg, Belgium, and the Netherlands in this chapter

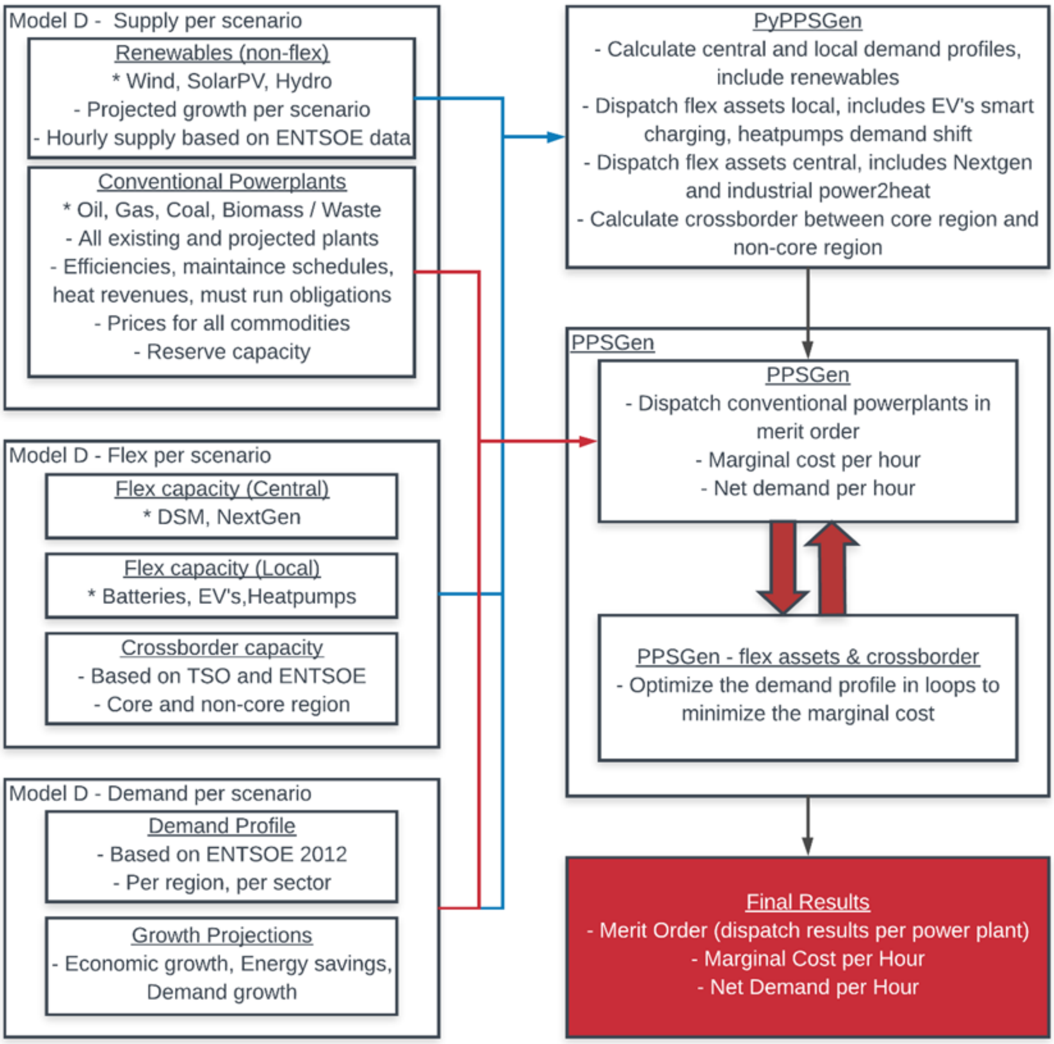


Figure 2.P: PPSGen model schematic

3 Annex to chapter 6: Technology

3.1 Overview of related projects

3.1.1 Porthos CCS project – NL

Port of Rotterdam, EBN and Gasunie are partners in a CCS project called Porthos, with the ambition of capturing 2-5 Mt/year of CO_2 from industrial emitters in the Rotterdam area. The CO_2 would be transported by onshore pipeline to the Maasvlakte area, from where it will be transferred by offshore pipeline to final storage locations in depleted gas fields.[7]

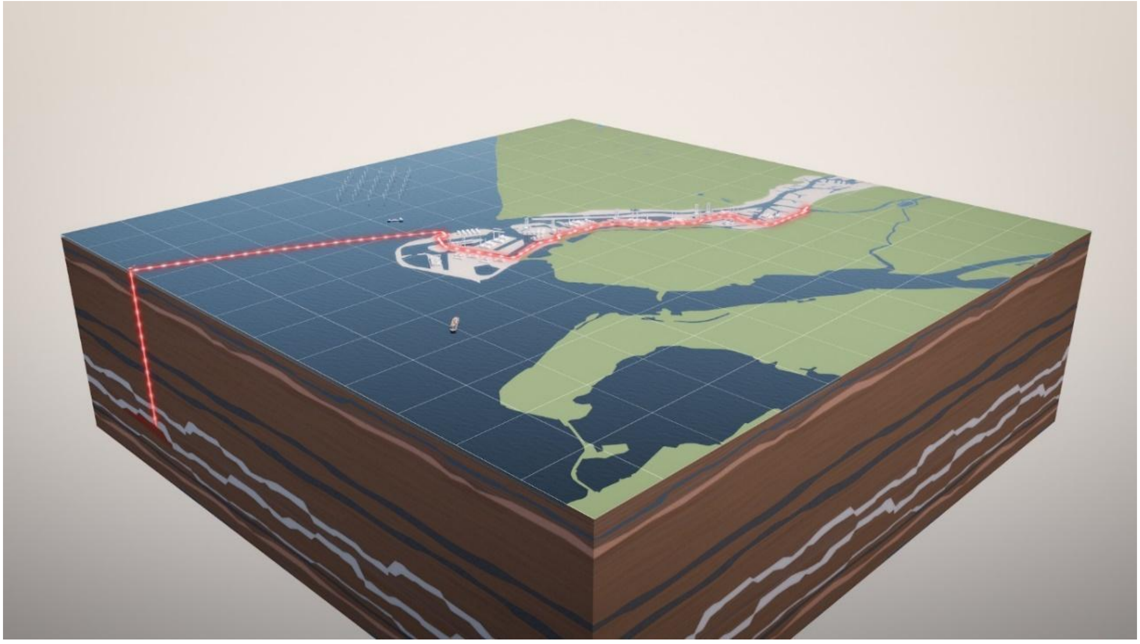


Figure 3.A: Map showing the envisaged routing for the CO_2 transport trunkline of the Porthos project (Image by EBN) [8]

A feasibility study has been carried out but not yet made public / no additional information available on cost estimates. Overall CO_2 transport and storage costs for large scale CCS infrastructure in The Netherlands are however presented in a recent report (EBN / Gasunie, 2017).

TNO also issued a report recently, as part of the ELEGANCY program, on CCS in The Netherlands, specifically focusing on CO_2 transport and storage costs (TNO, 2018).

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[7] https://www.portofrotterdam.com/en/news-and-press-releases/port-authority-gasunie-and-ebn-studying-feasibility-of-ccs-in-rotterdam (accessed 09.10.2018)

[8] https://www.ebn.nl/co%E2%82%82-opslag-onder-noordzee-technisch-haalbaar-en-kosteneffectief/

(accessed 09.10.2018)

3.1.2 H2M / Magnum project – NL

Equinor, Nuon/Vattenfall and Gasunie have contracted Mitsubishi-Hitachi Power Systems (MHPS) to evaluate the possibility of using blue hydrogen for low-carbon electricity generation at the Magnum power plant in Eemshaven.[9, 10]

If running at full capacity, each of the three 440MW CCGT would generate roughly 1.3 Mt/year of CO_2 emissions. The total potential for reducing CO_2 emissions using pre-combustion technology is in the order of 3-3.5 Mt/year.

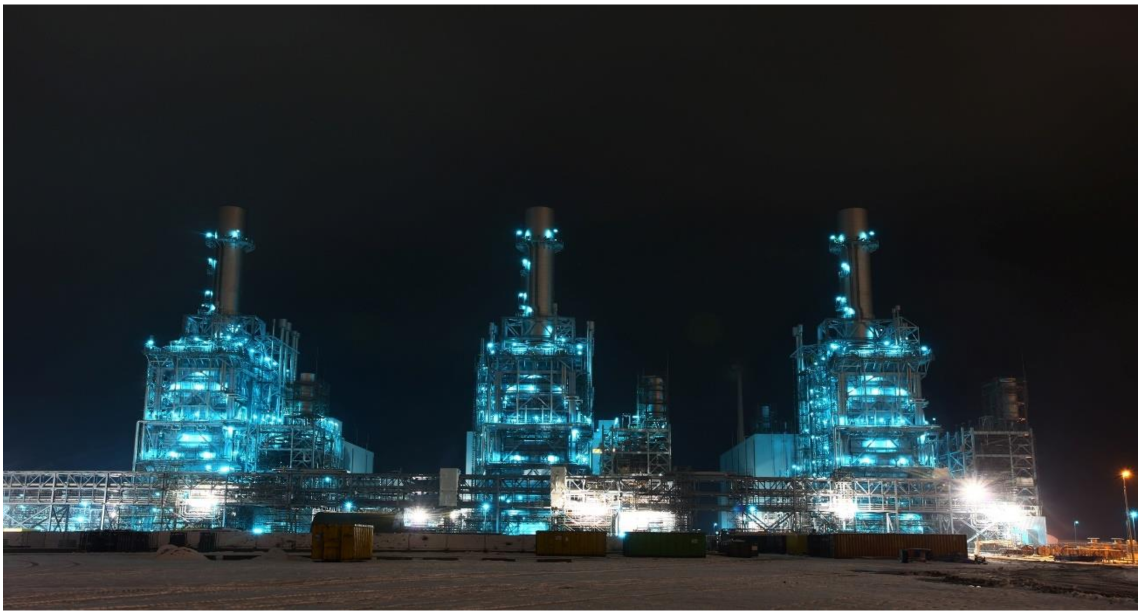

Figure 3.B: Vattenfall's gas power plant Magnum (Image by Nuon)

Additional details on the technical design selected for producing blue hydrogen or on the overall project economics have not been made public yet.

[9] https://www.businesswire.com/news/home/20180309005306/en/MHPS-Participate-Hydrogen-Conversion-Project-Natural-Gas (accessed 09.10.2018)

[10] https://www.equinor.com/en/news/evaluating-conversion-natural-gas-hydrogen.html

(accessed 09.10.2018)

3.1.3 HyNet North West – UK (Cadent, 2018)

HyNet is a medium scale decarbonization project (estimated CO_2 emission reduction of 1.1Mtpa, project CAPEX in the order of £920 M), with a fast implementation schedule. FEED is scheduled to start in Q1 2021, with the FID decision gate planned one year later.

The selected technology for hydrogen production is ATR – two trains with a combined capacity of 890 MW (equivalent to the forecasted peak displacement of natural gas by hydrogen).

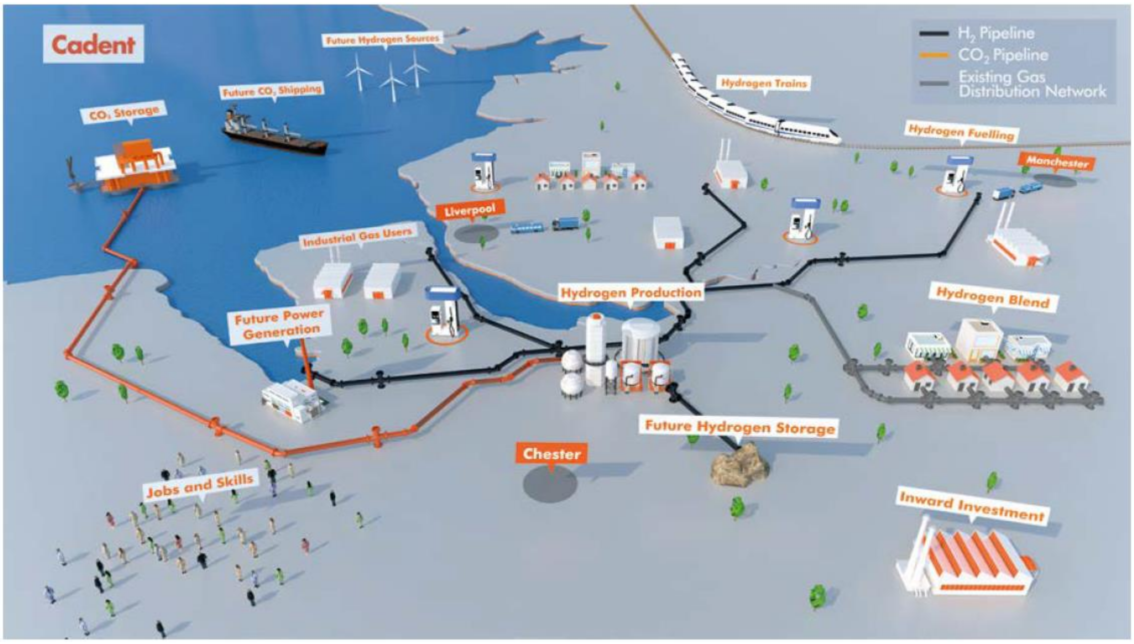

Figure 3.C: Indicative Representation of the HyNet Project (Image by Cadent Gas)

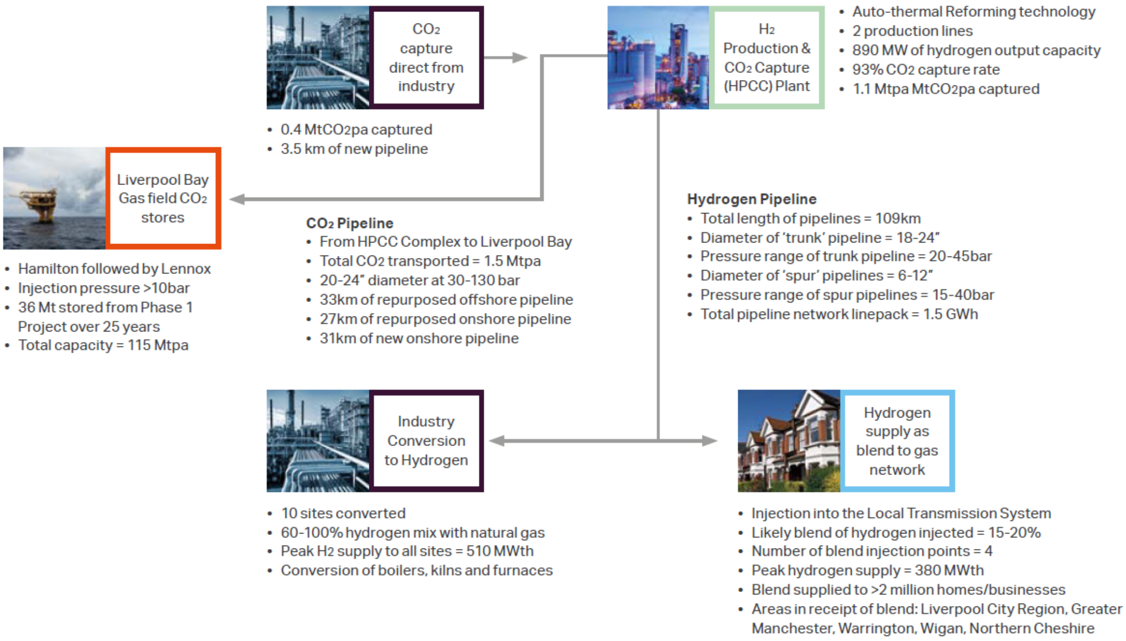

Figure 3.D: Key Data for HyNet NW Phase 1 Reference Project (Image by Cadent Gas)

Engagement with industrial partners is encouraging and no fundamental technical 'show-stoppers' have been identified. Many burner manufacturers and OEMs are experienced in designing and developing equipment for operation on fuel gases with high hydrogen content. Still more extensive validation is required for a broad conversion of furnaces/turbines at manufacturing sites to hydrogen firing.

Project Element[1]	Related Information	Average Unit Cost (£M)	Total Cost (£M)
Hydrogen Production and CO_2 Capture	HPCC plant comprises two ATRs, producing around 890 MW of hydrogen at pressure[2]	£256/unit	£513
Hydrogen Transport	Transport of 890 MW of hydrogen in new 109km onshore hydrogen pipeline from HPCC plant to industrial cluster and blend injection points	£1.65/km	£178
Hydrogen Compression and Injection to LTS	No compression required at HPCC plant, but additional equipment needed to inject hydrogen into the four LTS injection sites	£5/site	£20
Conversion of Industry to Hydrogen	Modifications to boilers, kilns and furnaces at 10 large industrial sites	£7.8/site	£78
CO_2 Transport	New 31km onshore pipeline from ATR plant to existing pipeline at Connah's Quay[3]	£2.03/km	£63
CO_2 Facilities	Modifications to existing Hamilton platform	n/a	£27
CO_2 Storage	Includes design, procurement, construction and commissioning of wells, licensing and permitting	n/a	£31
		TOTAL	£920

Notes:

1. The battery limit for CCUS costs is from the inlet to the CO_2 compressor at the HPCC plant
2. Includes costs of CO_2 compression
3. Also includes costs for modifications to existing gas pipelines which are repurposed for CO_2

Table 3.A: HyNet Capex Data (Image by Cadent Gas)

Overall OPEX for this project is estimated to be in the order of £85 M/annum.

Based on these values, the overall cost of CO_2 abatement for this project was estimated at £114 / ton CO_2.

3.1.4 H21 North of England – UK (Northern Gas Networks, Equinor, Cadent, 2018)

This project is a continuation and expansion (10x larger scope) of the H21 Leeds City Gate feasibility study. (Northern Gas Networks, 2016) Equinor is now the main industrial partner of Northern Gas Networks in the project, with Cadent also contributing to the long term vision for decarbonizing the gas grid in that area of the UK using blue hydrogen.

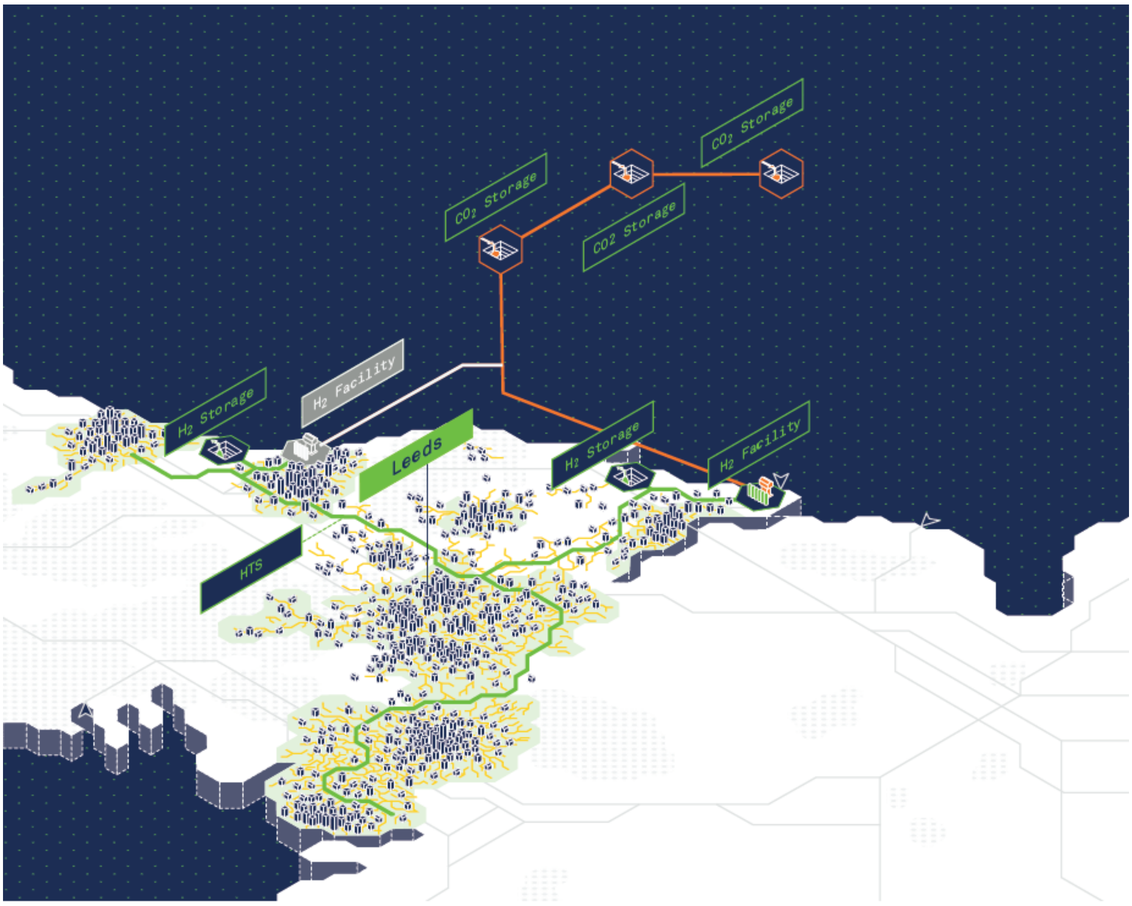

Figure 3.E: Map of H21 North of England (NoE) facilities and storage (Image by: Equinor)

Key Technical Aspects of H21 NoE:

1. Deep decarbonization of 14% (85 TWh) of UK heat by 2035. Converting 3.7 million meter points across Leeds, Bradford, Manchester, Liverpool, Hull, York, Teesside and Newcastle to hydrogen.
2. A 12.15 GW hydrogen production facility, comprised of 9 parallel trains.
3. 8 TWh of inter-seasonal hydrogen storage (equivalent to 62 thousand Australian mega batteries)
4. A CCS scheme with scaling capacity up to 20 Mtpa by 2035
5. A 125 GW hydrogen transmission system
6. A 6 phase UK roll-out strategy with the ability to decarbonize UK heat, 50% electric and transport by 2050

A very extensive report was issued in Nov 2018, covering all relevant aspects for a project of this nature: heat demand, natural gas supply, hydrogen production, transport, storage and distribution, CCS, CO_2 footprint of the entire chain, project financing, a plan for the FEED phase and a long term vision for how the network could expand.

The integrated design is illustrated in the diagram below, broken down into the individual components of a hydrogen-CCS chain:

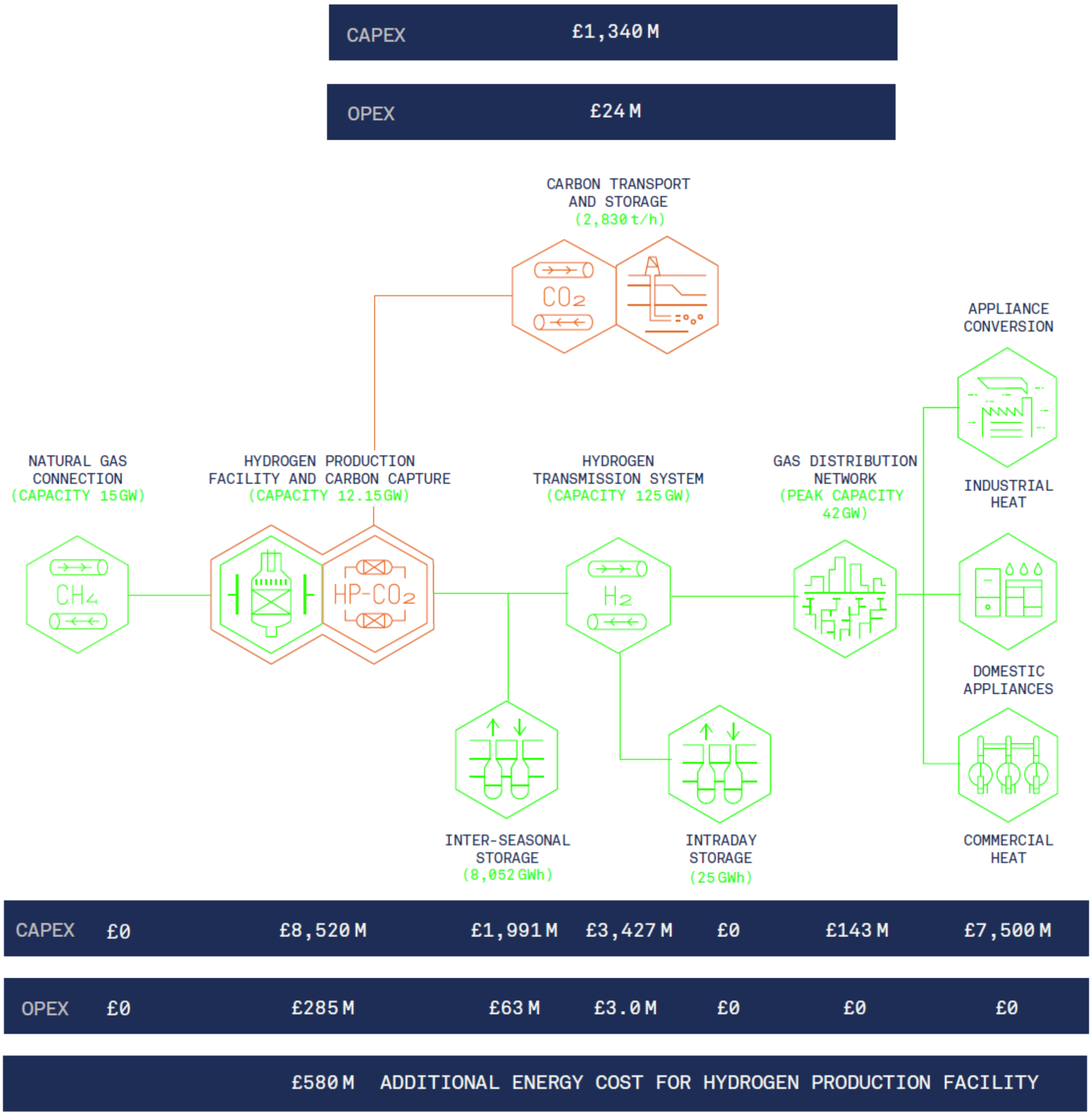

Figure 3.F: H21 North of England (NoE) project costs (CAPEX and OPEX) (Image by: Equinor)

Various technology solutions were evaluated for each of the main steps. The feasibility study resulted in the following selection of technologies for the proposed hydrogen-CCS chain:

- Blue Hydrogen production facility:
  - 9 x 1.35 GW ATR+GHR trains, with 9 x 2,900 tpd ASUs delivering the O_2
  - A dedicated 700MW hydrogen fired CCGT power plant
  - High pressure CO_2 capture from the syngas, using MDEA.
  - Hydrogen compression at 80 bar and CO_2 compression at 300 bar for export

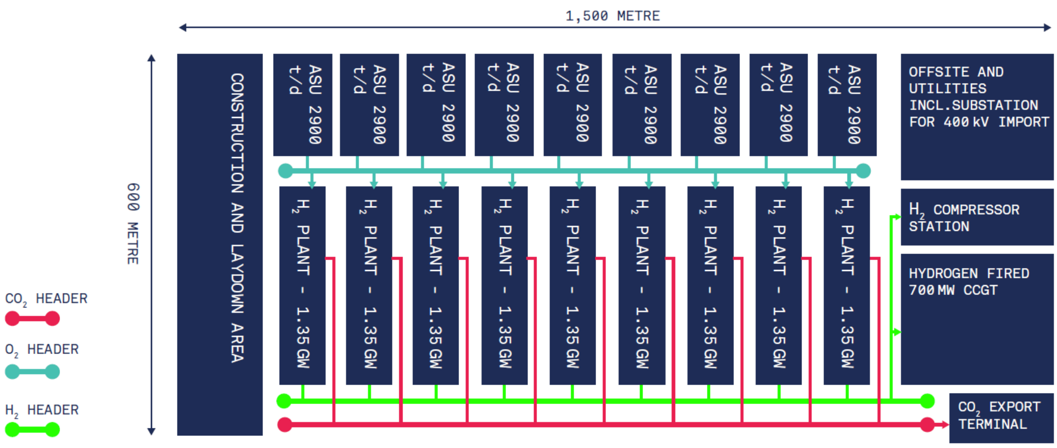

Figure 3.G: H21 NoE Hydrogen Production Facility Layout (total design capacity 12.15GW) (Image by: Equinor)

Despite the need for ASUs, the ATR+GHR configuration outperforms the best SMR option considered in terms of CAPEX and CO_2 capture:

1.5 GW H_2 PRODUCTION	ATR OPTION 2	SMR OPTION 2
Carbon capture rate (%)	94.1	91.2
CO_2 footprint (g CO_2/kwh)	13.1	20.5
Efficiency % (HHV)	79.9	79.5
CAPEX (£m) – Total	947	1,082
Electric Power Import (MW)	72.6	35.6
CAPEX £/kWH$_{2\,HHV}$)	631	721
Area (ha)	15-20	35-40
Configuration	1 ATR train + ASU	2 SMR trains

Table 3.B: Comparison of the best ATR and SMR concepts for H21 NoE (Image by: Equinor)

- A new 125 GW dedicated hydrogen transmission system. It's necessary to build a new system for transmission, since it's not possible to interrupt natural gas supply to existing customers while the project is under construction.
- Salt caverns were evaluated as the cheapest solution for inter-seasonal hydrogen storage and a system with 8 TWh of storage capacity is included, designed to cope with the most severe winter conditions of the last 5 years.
- CO_2 transport by onshore and offshore pipelines for permanent storage, either in depleted gas fields near the UK coast or in a saline aquifer in the Southern Troll area (near the Norwegian coast). Overall CO_2 transport and storage costs are estimated to be under 10€/ton CO_2.

3.2 Model results for repowering the coal-fired power plants

		1000 MW coal fired power plant							
				H-Vision low case		H-Vision reference case		H-Vision high case	
		Generic coal case	Minimum biomass case	Baseload operation	Max H2 use	Baseload operation	Max H2 use	Baseload operation	Max H2 use
Parameter	Units			Biomass + min steam integration	+ direct H2 firing + additional steam	Biomass + min steam integration	Full load + H2 GT topping cycle + additional steam	Biomass + min steam integration	Full Load + H2 GT topping cycle + direct H2 firing + additional steam
Heat input coal	[MWth]	2174		0	0	0	0	0	0
Heat input Biomass	[MWth]		830	830	613	830	1395	830	1069
Heat input hydrogen (direct firing)	[MWth]			0	217	0	0	0	326
Heat input hydrogen (GTs)	[MWth]			N/A	N/A	0	805	0	805
Steam from ATR HP steam (100 bar)	[tph]			52	84	112	225	210	302
Steam from ATR MP steam (30 bar)	[tph]			17	28	37	75	70	101
Heat input to steam turbine (HP steam, superheated at 600°C)	MWh]			52	84	113	227	211	303
Superheating heat extracted from the boiler	[MWth]			-11	-18	-24	-49	-45	-65
Heat input from ATR MP steam	[MWth]			13	22	29	59	55	79
Total heat input	[MWth]	**2174**	**830**	**884**	**918**	**948**	**2437**	**1050**	**2517**
Power output steam turbine	[MWe]	1000	340	360	395	382	965	418	1000
Power output gas turbines	[MWe]						294		294
Total power output	[MWe]	**1000**	**340**	**360**	**395**	**382**	**1259**	**418**	**1294**
Power production efficiency	[%]	46%	41%	41%	43%	40%	52%	40%	51%
Hydrogen GT incremental efficiency	[%]	N/A	N/A	N/A	N/A	N/A	59%	N/A	60%
Biomass energy input (relative to generic coal case)	[%]	0%	38%	38%	28%	38%	64%	38%	49%
Gas turbine size	[MW]					147		147	
Number	[-]	N/A	N/A	N/A		2		2	
Total capacity	[MW]					294		294	
Investment estimates									
Modification for direct H2 firing	[M€]			25				25	
Tie-ins + BOP for steam integration	[M€]			30		40 + 5		40 + 15	
Gas turbine	[M€]					120		120	

Table 3.C: Model results for a repowered 1000 MW coal-fired power plant

		800 MW coal fired power plant							
				H-Vision low case		H-Vision reference case		H-Vision high case	
		Generic coal case	Minimum biomass case	Baseload operation	Max H2 use	Baseload operation	Max H2 use	Baseload operation	Max H2 use
Parameter	Units			Biomass + min steam integration	+ direct H2 firing + additional steam	Biomass + min steam integration	Full load + H2 GT topping cycle + additional steam	Biomass + min steam integration	Full Load + H2 GT topping cycle + direct H2 firing + additional steam
Heat input coal	[MWth]	1739	0	0	0	0	0	0	0
Heat input Biomass	[MWth]		730	730	556	730	1023	730	762
Heat input hydrogen (direct firing)	[MWth]			0	174	0	0	0	261
Heat input hydrogen (GTs)	[MWth]			N/A	N/A	0	805	0	805
Steam from ATR HP steam (100 bar)	[tph]			41	67	90	180	168	241
Steam from ATR MP steam (30 bar)	[tph]			14	22	30	60	56	80
Heat input to steam turbine (HP steam, superheated at 600°C)	MWh]			41	67	90	181	169	243
Superheating heat extracted from the boiler	[MWth]			-9	-14	-19	-39	-36	-52
Heat input from ATR MP steam	[MWth]			11	17	23	47	44	63
Total heat input	[MWth]	**1739**	**730**	**773**	**800**	**824**	**2017**	**906**	**2081**
Power output steam turbine	[MWe]	800	299.3	314	323	331	753	359	780
Power output gas turbines	[MWe]						294		294
Total power output	[MWe]	**800**	**299**	**314**	**323**	**331**	**1047**	**359**	**1074**
Power production efficiency	[%]	46%	41%	41%	40%	40%	52%	40%	52%
Hydrogen GT incremental efficiency	[%]	N/A	N/A	N/A	N/A	N/A	60%	N/A	61%
Biomass energy input (relative to generic coal case)	[%]	0%	42%	42%	32%	42%	59%	42%	44%
Gas turbine size	[MW]					147		147	
Number	[-]	N/A	N/A	N/A		2		2	
Total capacity	[MW]					294		294	
Investment estimates									
Modification for direct H2 firing	[M€]			25				25	
Tie-ins + BOP for steam integration	[M€]			30		40 + 5		40 + 15	
Gas turbine	[M€]					120		120	

Table 3.D: Model results for a repowered 800 MW coal-fired power plant

3.3 Brief description of ATR technology

Auto-Thermal Reforming (ATR) uses pure O_2 for the partial oxidation of the feed in the flame section, which is followed by a catalyst bed in the steam reforming section of the reactor. The core benefits of this system are that the heat generated by partial oxidation is consumed by the endothermic reforming reaction. This process is inherently energy-efficient, because the reactor operates without an external heat supply. In addition, since the oxidation occurs within the reaction chamber, there is no flue gas produced at this step and CO_2 capture is simplified.

Modern ATR units have higher reliability / lower unplanned downtime than SMR units, with a ramp up/down rate of 1.5% capacity per minute. Another advantage is that an ATR can be operated at very high pressures (up to and beyond 60 bar, at industrial scale), increasing the capacity of a single ATR unit, and eliminating the need to compress the outlet hydrogen stream.

Most ATRs currently in operation are used for ammonia and methanol production. A simplified process for the production of syngas from NG using is shown below:

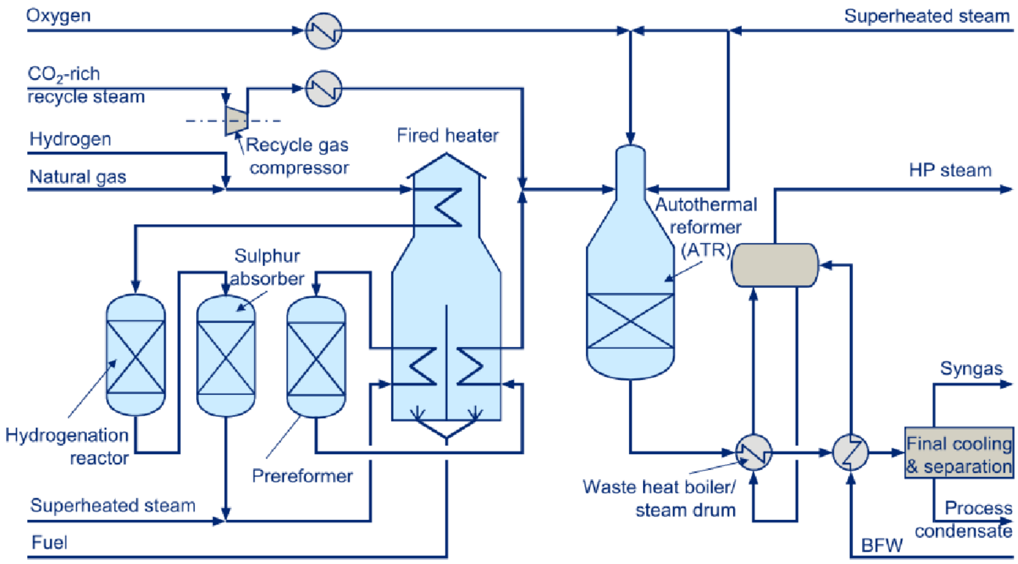

Figure 3.H: Syngas production equipped with Haldor Topsøe ATR stand-alone reforming. Reproduced from (Dahl, Christensen, Winter-Madsen, & King, 2014)

The main reactions that occur in this system are summarised below in Table 3.E.

Reactions		ΔH° [kJ/mol]
Steam Methane Reforming	$CH_4 + H_2O \leftrightarrow CO + 3H_2$	+206
Methane Partial Oxidation	$CH_4 + \frac{1}{2}O_2 \leftrightarrow CO + 2H_2$	-36
Water Gas Shift	$CO + H_2O \leftrightarrow CO_2 + H_2$	-41
Methane Complete Oxidation(undesired)	$CH_4 + 2O_2 \leftrightarrow CO_2 + 2H_2O$	-800
CO Oxidation (undesired)	$CO + \frac{1}{2}O_2 \leftrightarrow CO_2$	-284
Hydrogen Oxidation (undesired)	$H_2 + \frac{1}{2}O_2 \leftrightarrow H_2O$	-242

Table 3.E: Overview of main reactions that take place in the ATR process.

In an ATR reactor, the pre-reformed or pre-heated NG reacts with O_2 and steam at a temperature of approx. 1200°C, then passes through the catalyst bed where steam reforming of CH_4 and WGSR take place at temperatures of 850 – 1050°C. The syngas mixture leaves the reactor at temperatures of approx. 725°C. The overall ATR process can be operated as exothermic, endothermic, and thermoneutral, depending on the hydrocarbons : oxygen : steam ratio in the feed stream (Ahmed & Krumpelt, 2001).

With respect to CCS integration, ATR technology presents the same benefits as POX: there is no flue gas stream, as the heat generation takes place inside the reactor. Also, the high temperature operation allows for a high CH_4 conversion to syngas, where most of the CO is converted to CO_2 in the WGSR, having a high purity CO_2 at high pressure as output, ideal for CCS. The reactor can also be operated at high pressure, which helps reduce or even eliminate the cost of hydrogen compression, depending on the application.

Three different references for an ATR + CCS plant (all with high pressure CO_2 capture) were reviewed and are presented below in Table 3.F, together with the key parameters of the HP ATR concept used for H-Vision.

Parameter	ATR+HP CCS [H21] (1.3 GW H_2) 1 ATR train	ATR+CCS [NTU] (0.7 GW H_2) 1 ATR train	ATR+PSA CCS [TNO] (0.4 GW H_2) 1 ATR train	HP ATR + HP Rectisol CCS [Air Liquide] (2.1 GW H_2) 1 ATR train
CO_2 capture [%]	94.5%	92.3%	94.0%	88%
CO_2 footprint [kg CO_2 / MWh H_2]	15.4	19.1	-	28
Efficiency (HHV) Efficiency (LHV)	76.0% 71.1%	87.7% (excl. CCS) 82.0% (excl. CCS)	81.9% 76.4%	82.3% 77.7%
Electric power import [MW_e]	53.8	27.1 (excl. CCS)	32.3	128
CAPEX per capacity [M€ / MW H_2]	-	1.40	-	0.43
OPEX per capacity [M€ / MW H_2 / year]	-	0.24 (incl. CCS)	-	-

Table 3.F: Comparison of ATR + CCS processes. Efficiency is defined as total hydrogen energy output (LHV) per total energy input as NG (LHV). Design capacities are indicated between brackets, below each name. Parameters related to hydrogen production are calculated on LHV basis. In the header, [H21] refers to (Northern Gas Networks, Equinor, Cadent, 2018), [NTU] refers to (Jakobsen & Åtland, 2016), [TNO] refers to a simulation made in-house at TNO, by Laurens van Vliet. [Air Liquide] refers to the ATR concept proposed for H-Vision

3.4 Port infrastructure

In this Annex the envisaged port infrastructure fort he minimum and maximum scope development concepts is shown. The envisaged port infrastructure for the reference scope development concept can be found in Figure 6.10 of the main report, which is located in section 6.4.1. (gas compression and transport) of the main report.

*Figure 3.I: **Minimum scope (1.1 GW hydrogen demand)** overview of the blue hydrogen production and transport infrastructure for the Rotterdam port, including both RFG and NG heating demand from end users. 'J#' are identifiers for junction points where the transmission pipeline splits into smaller lines going directly towards the plants.*

*Figure 3.J: **Maximum scope (5.2 GW hydrogen demand)** overview of the blue hydrogen production and transport infrastructure for the Rotterdam port, including both RFG and NG heating demand from end users. 'J#' are identifiers for junction points where the transmission pipeline splits into smaller lines going directly towards the plants.*

3.5 Steam integration

According to estimates received from Air Liquide, a 2.4 GW mega-scale ATR has approx. 405 t/h of excess steam:

- Roughly 75% of this is available at high pressure (up to 100 bar)
- The rest is available as MP steam (~30 bar)

- The steam can be delivered with a superheating margin of 20°C

For simplification, steam production is assumed to scale linearly with plant size, and also with throughput (e.g. at 50% of production capacity the excess steam is also 50% of max).

An ATR plant is a net power importing plant, because of the associated air separation unit. Most of the required electricity can be produced on site using excess steam, by adding a steam turbine to the design. Considering the proposed location of the plant, an alternative is to make use of spare power generation capacity available at the nearby Maasvlakte power plants:

- Replacing coal with biomass will reduce the firing duty of the existing solid fuel boilers, which means the steam turbines will be underutilized.
    - HP steam from the H-Vision plant can be used directly for power generation, thereby increasing turbine utilization and efficiency.
- MP steam from the H-Vision plant can be integrated at high efficiency within the BFW preheat sections of the power plants, which is.
- This approach eliminates the CAPEX associated with a new steam turbine and accompanying utilities and condensate systems.
    - The power plants already have massive condensate systems which can easily handle the streams from the H-Vision plant.
    - The total cost savings associated with steam and utilities integration, for the Hydrogen production plant, is estimated to be in the order of 150M€ for a 2.4 GW HP ATR.

To enable this integration, high pressure / high temperature steam transfer pipelines are needed between the H-Vision site and the two power plants at Maasvlakte. Condensate return lines will also be required of course, as well as tie-ins and other modifications at the power plants to enable integration of the steam from the hydrogen production plant.

At this stage it is very difficult to provide cost estimates for the required modifications, without knowing the exact location of the hydrogen plant or the configuration of the utilities systems. For each of the cases considered, placeholder cost estimates were used to account for the steam and condensate pipelines, as well as required tie-ins and other modifications:

- Minimum scope: 30 M€ per power plant
- Reference scope: 45 M€ per power plant
- Maximum scope: 55 M€ per power plant

This approach raises the issue that the power plants have a lower reliability than what is expected from the ATR unit. This adds a failure mode and could potentially result in unplanned downtime for the blue Hydrogen plant, if steam cannot be exported and BFW returned.

We expect this to be mitigated by using the dump cooler systems already available at the power plants, but it will mean that overall efficiency is reduced considerably if one of both power plants are not using the steam. A back-up grid connection is also required.

3.6 Hydrogen backbone network

For underground salt caverns at Zuidwending to enable flexible operation of a hydrogen production facility located at Maasvlakte, a connecting pipeline of suitable capacity is clearly required. Gasunie already evaluated the feasibility of developing a large scale nation-wide hydrogen distribution grid, as shown below in Figure 3.K.

A cost-effective approach is to maximize the reuse of existing large diameter (30" < D < 48") natural gas lines. About 160-190 km of high pressure pipelines will have to be added, and new compressors will be required for the recompression stations. Together with upgrading costs for existing lines, the overall investment required to establish a national distribution grid for hydrogen is estimated to be in the order of 1,500 M€.

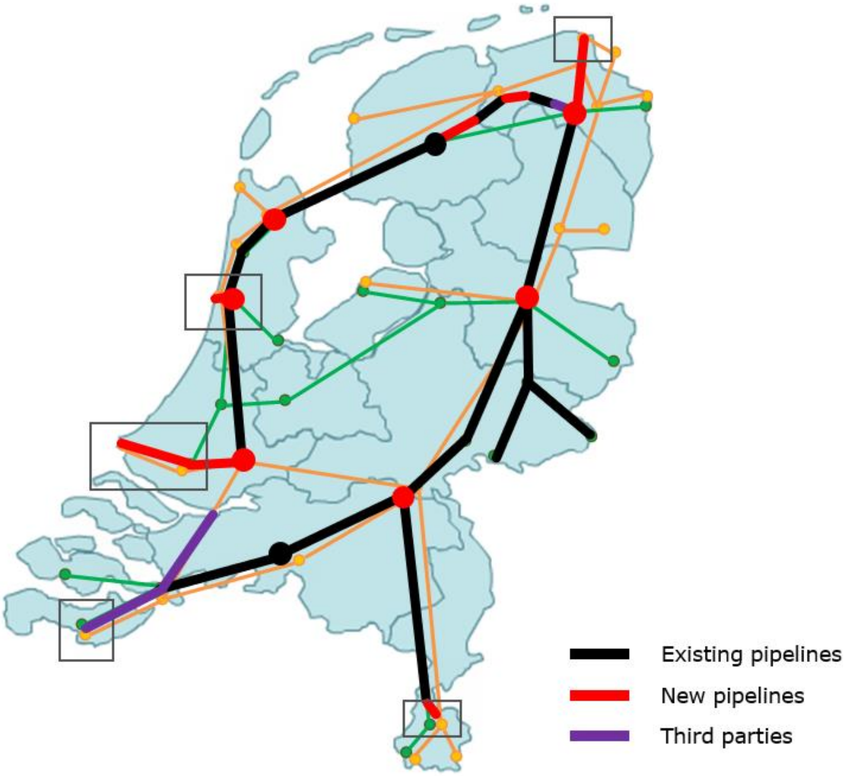

Figure 3.K: Envisaged Hydrogen Backbone pipeline network, ca 2030 (source: Gasunie).

To connect the Maasvlakte region with the underground storage facility in Zuidwending (when using the current pipeline track), a total length of approximately 377 km of pipeline is needed. In 2030, 280 km of the current NG pipelines within that corridor can be used for hydrogen transport. This leaves approximately 97 km of additional pipeline needed (62 km in the Rotterdam area between Maasvlakte and Wijngaarden and the other 35 km in the Northern part of the Netherlands).

Connecting the hydrogen network of the H-Vision project with the storage facility at Zuidwending in 2025 will be more challenging, because not all of the existing NG pipelines will be already available. Gasunie will investigate the availability of infrastructure for H_2 transport between 2020 and 2030, this is expected to be finished before the end of 2019. Alternatively, project planning can be done in such a way that storage-based flexibility is only needed after 2030, allowing sufficient time to connect the H-Vision network in the Rotterdam area with the underground storage facilities at Zuidwending.

3.7 Future technology developments

Several technologies aimed at improving the overall efficiency of gas reforming are currently being developed. This chapter provides a very brief overview of the ones that we consider to be relevant for the H-Vision concept, and more detailed descriptions have been included in the technical report of the project.

The following relevant topics are shortly discussed here:

- Integration with blue hydrogen production with the production of green hydrogen using the surplus of oxygen from water electrolyses, which might be soon an interesting option to be considered.
- New technology development of reforming technologies for different feedstocks the SWEGS technology.

There are more developments: electrical driven reformers and direct microwave reformers, however these developments are at a much lower technology technical readiness level and there not reviewed as a relevant option for H-vision.

3.7.1 Oxygen integration

Blue hydrogen is intended to be an energy transition precursor to green hydrogen. It's clearly beneficial to develop compatible infrastructure and prepare industrial sites for using green hydrogen in the future for high temperature heat applications. Another way to support the development of green hydrogen produced from electrolysis, is to provide value for co-produced O_2, thereby reducing overall hydrogen production costs.

- Using the co-produced O_2 from an electrolyser in the ATR unit leads to an OPEX saving. The energy required to compress O_2 is estimated to be around 15-20% of the energy consumption of an air separation unit.
- There is also potential for a CAPEX saving – a large scale electrolyser will produce enough O_2 to enable reducing the scale of the ASU, potentially by as much as 20-30%. Intermittency can be resolved by using a liquid O_2 buffer tank.

This integration between blue hydrogen and green hydrogen is being evaluated by Berenschot and TNO in the Waterstof Versneller project.

- An economic model is being developed to evaluate if the benefits (lower ASU OPEX and CAPEX) do indeed outweigh the additional investment (O_2 compressor and pipeline + larger liquid O_2 tank)

3.7.2 Sorption-enhanced water gas shift (SEWGS)

SEWGS is an intensified carbon capture technology developed by ECN, which combines the water gas shift reaction with in-situ removal of carbon dioxide. The integration increases the conversion of CO to almost 100%, while reducing the energy intensity of CO_2 capture by nearly 20% (compared to a HP amine absorption system).

In addition to the potential for energy savings, depending on the type of CO_2 capture technology selected, adding SEWGS to a blue hydrogen production process has the advantage of driving minimizing the CO concentration in hydrogen product. This improves the overall CO_2 capture rate of the blue Hydrogen chain.

This technology is being scaled up as part of the EU Stepwise project[11], aimed at reducing the carbon intensity of steel production. The same technology can in principle be applied to increase the energy efficiency of a blue Hydrogen production plant. As such, we recommend evaluating the integration potential at a later phase of the H-Vision project.

[11] https://www.stepwise.eu/project/how/

4 Annex to chapter 7: CO_2 transport & storage

4.1 Physical delivery and composition of the CO_2 transferred

The CO_2 captured in the Rotterdam port area from the hydrogen production processes (Steam Methane Reforming (SMR) and Auto Thermal Reforming (ATR)), and the refinery processes (e.g. IGCC) will contain impurities (other components) that result from the different energy conversion and capture processes.

The type and amount of other components in the 'CO_2 stream' depends on the fuels used and the type of capture process (including the type of solvent used). The presence and type of other components may vary considerably between post-combustion, pre-combustion and oxyfuel capture processes. Other components in the CO_2 captured from flue gases by means of post-combustion technologies originate from the fuel used and the air or oxygen feed to the system. Flue gases from coal/gas combustion will contain next to CO_2 nitrogen (N_2), oxygen (O_2) and water (H_2O), but also air pollutants such as sulfur oxides (SO_x), nitrogen oxides (NO_x), particulates, hydrogen sulfide (H_2S), carbonyl sulfide (COS), hydrochloric acid (HCl), hydrogen fluoride (HF), hydrogen cyanate (HCN), mercury, other metals and other trace organic and inorganic contaminants. Small amounts of the solvent (for post-combustion capture) might end up in the CO_2 as well. Pre-combustion separation may result in concentrations of N_2, H_2, CH_4, CO and also sulphur compounds like H_2S.

For technical, economical, safety and/or environmental reasons it may be necessary to reduce the amount of certain trace elements in order to guarantee safe and effective transportation and storage of CO_2. Reducing the concentration of trace elements and obtaining a high purity CO_2 stream is technically feasible, but adds purification steps to reach a higher than necessary purity can result in higher CAPEX and OPEX (e.g. increased energy consumption), strongly depending on the selected capture process. Too strict purity requirements might not be effective for the purpose of optimizing costs along the CCS chain especially with regard to the already existing and new to be built carbon capture units. Today there are no widely accepted standards for the quality of CO_2 required for CO_2 capture, transport and geological storage. Worldwide there are some example projects that set case-specific CO_2 qualities for pipeline transportation and storage but these are mainly the result of the agreement between the shipper, transporter and storage parties of CO_2.

4.1.1 Considerations that define the CO_2 quality

A high-quality stream of CO_2 can present fewer technical challenges to the transportation processes than does a less pure stream (depending on the nature of the impurities, as e.g. nitrogen tends to present less of an issue than H_2 or H_2O). There can also be cost savings with a more pure stream of CO_2 as less compression and energy is needed to transport the equivalent volume of CO_2 through the pipeline.

Figure 4.A below is a phase diagram of CO_2 which shows the critical and triple points and the key area of interest the supercritical region.

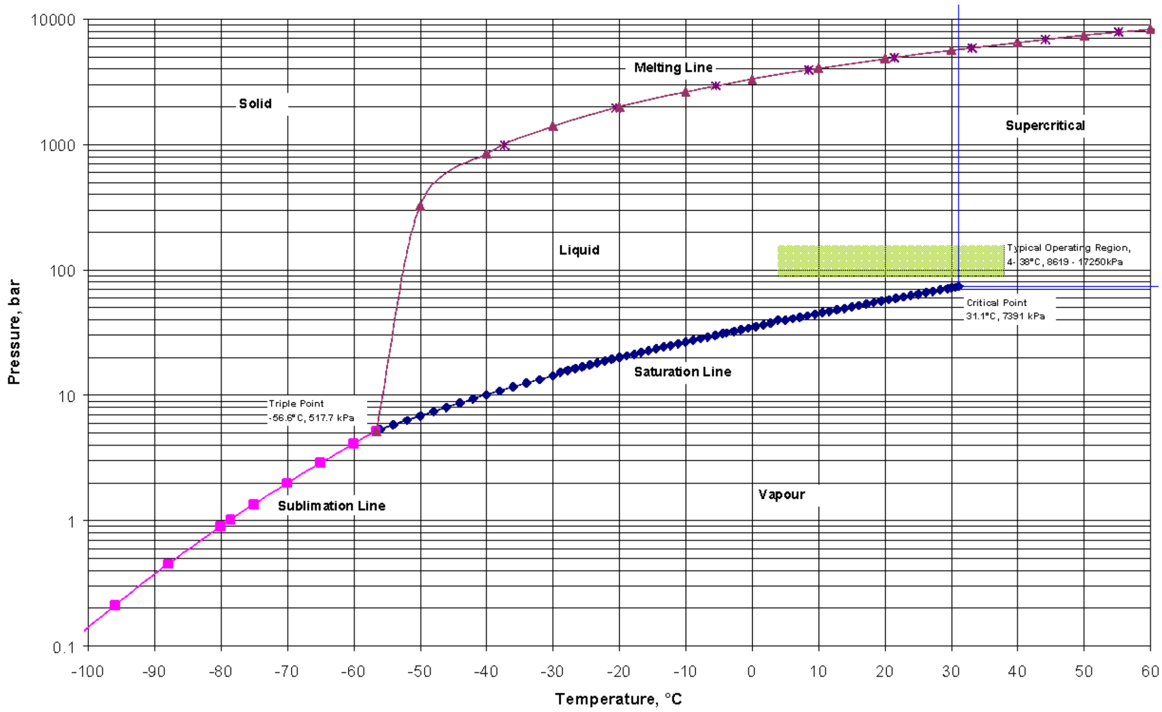

Figure 4.A: Carbon dioxide phase diagram

The properties of CO_2 are such that at supercritical conditions the density is relatively high, while viscosity is low, making it very suitable for transportation.

The prediction of properties is also key for the phase envelope, as a change in a contaminant concentration may radically alter the phase diagram.

It also seems sensible that limits be established on the amount of water permitted in the CO_2 stream (or compounds that can chemically form water by reaction of different impurities such as oxygen reacting with reduced sulphur species to form water and solid sulphur) and subsequently allowed to enter the pipeline. Excessive amounts of water in the CO_2 stream can produce carbonic acid, risking corrosion of pipeline materials. It may prove less costly to dry (i.e. dewater) the CO_2 stream prior to transporting rather than build a pipeline with more corrosive resistant steel or liners.

4.1.2 CO_2 composition

The effect of contaminants on CO_2 physical behavior is significant. The capture of the CO_2 from technology for hydrogen production chosen by H-vision (ATR) as well as the various sources to be developed under the Porthos project in the Rotterdam port will result in an increased number of contaminant and concentration variability. Hence there will be a need to consider the combined flow as well as the storage site requirements.

Constraints herein are set by:

- what each reservoir can accept (impact of dust particles on perforations and rock, impact of impurities on reservoir rock and fluids, impact of water injected at very low temperatures)

- what the steel of the well tubing, surface pipework, compressors and valves can tolerate (given corrosion allowance and lifetime of equipment)
- what the capture/extraction processes can generate by default (low cost/high efficiency) versus the cost to generate higher purity with no interruption
- what the CO_2-use customers can accept. However, their volume requirements may be small compared to the total volume captured.

Deviations from specification limits may be acceptable on a short term basis if their effects are blended away within the total system. This reasonable approach to system design is recommended and requires on-line monitoring, automatic warning systems and a pre-agreed action plan in the case of extended periods of significant deviation from specification per source.

Most capture processes generate high-purity CO_2 by default and the probability of quality upset is low. Hence more attention should be paid to CO_2 supplies with less reliability and lower quality.

In Table 4.A an overview is given of the CO_2 composition ranges related to the different type of capture sources.

Composition ranges for CO_2 streams (Anheden et al., 2005; IEAGHG, 2011; IPCC, 2005; Kather and Kownatzki, 2011; Oosterkamp and Ramsen, 2008).

Component		Pre-combustion		Post-combustion		Oxyfuel	
		Min	Max	Min	Max	Min	Max
CO_2	vol%	95.6	99.7	99.8	99.97	85	99.94
SO_x	vol%			0.001	0.01	0.007	2.5
NO_x	vol%			0.002	0.01	0.01	0.25
H_2S	vol%	0.01	3.4				
CO	vol%	0.03	0.4	0.001	0.002		
Ar	vol%	0.03	1.3	0.003	0.045	0.01	5.7
O_2	vol%	0.03	1.3	0.003	0.03	0.01	4.7
N_2	vol%	0.03	1.3	0.021	0.17	0.01	7
H_2	vol%	0.002	1.7				
CH_4	vol%	0.035	2		0.01		
Hydrocarbons	vol%			0.003	0.01		
HCN	vol%		0.0005				
NH_3	vol%		0.003		0.005		
CH_3OH	vol%		0.02				

Table 4.A: CO_2 composition for different capture sources.

In considering a CO_2 pipeline, in particular where there is more than one source, defining the range of the composition is essential. For 'single source to single storage' solutions the composition range will be defined by the emitter and the acceptable limits to the storage site. The acceptable composition for CO_2 streams is however not just set by the emitter or capture technology but by the other elements, particularly storage and transportation.

Worldwide (e.g. USA, Canada and Norway) there are a few single source to single sink examples such as Weyburn, Gorgon, Sleipner, Snøhvit, etc.

In the Netherlands, a 300 km gaseous CO_2 pipeline transport network owned and operated by OCAP (A Linde company) is in place supplying captured and purified CO_2 from two different sources (fermentation at ALCO Biofuel and gasification at Shell Pernis) to greenhouse areas located between Rotterdam and Amsterdam.

In addition Air Liquide Rozenburg (ATR source) and Linde Europoort (gasification source) have a CO_2 purification and liquefaction plant in operation producing liquid CO_2. In the past several CO_2 Capture Feed studies (Coal Fired Power Plant, ROAD and hydrogen Production, SMR) have been executed where the intended captured CO_2 had a quality which is suitable for both CCU and CCS applications.

As mentioned earlier in this document there are no worldwide quality standards or specifications for CO_2 to be used in CCS related projects. For the H-Vision study the preliminary CO_2 specification submitted by Porthos is used as a first attempt to establish a general CO_2 specification acceptable for CCS applications.

4.1.3 Porthos CO_2 Specification for CCU

Porthos has a long-term vision to also supply concentrated CO_2 flows to CCU reuse technology in the future. Although these technologies are currently still in very early stages of development Porthos believes these are crucial for circular economy solutions needed to decarbonize the port in the long term. Reuse in the glass house industry is the only current viable CCU application, but other applications will reach viability in the near future. For this reason Porthos is also considering the effects of the impurities and studying the feasibility of tightening impurity specifications to facilitate such reuse processes as efficiently as possible.

Porthos intends to fix its specification for the CO_2 in its system by June 2019, which is unfortunately after the submission date of this report. Porthos is evaluating against 2 reference specifications: The ISO specification (>95% CO_2) and OCAP spec (> 99% CO_2). See next section for more details.

At this time the conservative option is to require H-vision plant to comply with the OCAP specification which is achievable for an ATR hydrogen production facility

4.1.4 ISO spec for CCS

At this moment in time the Porthos project in Rotterdam is considering following the ISO standard for CCS systems.

The ISO standard is summarized as follows:

Table A.1 — Indicative levels of main CO_2 impurities and factors driving these levels

Species	Indicative levels (volumetric composition in ppmv, unless stated as mol%)		
CO_2	>95 mol%[a]		
H_2O	Corrosion, 20 to 630[b], Hydrate, <200[c,d]		Avoiding the formation of corrosive phases and solids in the pipeline is essential for safe operation of the CO_2 pipeline system. There are a number of possible cross-chemical reactions that have the potential to form sulfuric/sulfurous acid, nitric acid and elemental sulfur when water and SO_2, NO, NO_2, O_2 and H_2S are present[33], also N_2O, N_2O_4[40]. Presently, there is no publically available model that can predict which of the reactions are thermodynamically and kinetically possible and favourable when the impurities are mixed. Since the maximum concentration of a single impurity will depend on the concentration of the other impurities, it is not possible due to lack of data and current understanding to state a fixed maximum concentration of a single impurity when other impurities are, or may be, present.
H_2	<0,75 mol%[e,f]	<4 % total for all non-condensable gasses, but individual contributions may also be significant	
N_2	<2 mol%[f,g]		
Ar	[f]		
CH_4	[f,g]		
CO	<0,2 mol%[j,k]		
O_2	[f,h]NB. Downstream limitations		
H_2S	<200[g,i,k]	Individual values, each below STEL,[m] but see Footnote n.	
SO_2	Health and Safety < 100[k,l]		
NO_2	Corrosion < 50[n]		
Amine		The presence of amines, MeOH, EtOH, glycols and other water soluble components (e.g. HCl, NaOH, other salts) will facilitate the formation of an aqueous phase (free water) and reduce the concentration of water in the CO_2 at which a separate aqueous phase is formed. The maximum concentrations that are acceptable will depend on the concentration of the other impurities (see above note).	
Methanol			
Ethanol			
Glycol			
C_2+	<2,5 mol%[o]		

a Industry accepted interpretation of "overwhelmingly CO_2" required by the London Convention and Protocol which came into force in February 2007.

b The Cortez and Central Basin pipelines in the USA have 630 ppmv H_2O, but it is noted that they also have <26 ppmv of H_2S, <14 ppmv of O_2 and no SO_x or NO_x (see References [61] and [55]).

c A figure of 250 ppm is recommended in Reference [62], which states "In case of a system shut-in or start-up, the risk of hydrates is low if the water content of the CO_2 stream is below 250 ppm. In situations of rapid depressurization, even a low water content level might not be sufficient to avoid hydrates." An additional margin has been applied to recognize this. The maximum acceptable concentration will depend on the pressure/temperature operation window. It is recognized that a number of pipelines have been operated for a long time with a target water concentration of 630 ppmv without reported hydrate incidences. See also Footnote b.

d For measures to avoid hydrate formation, see C.2.

e See C.2 for criteria on which the hydrogen content should be decided.

f The presence of "non-condensables", particularly, H_2, H_2S and N_2, but also O_2, Ar, CH_4 and CO affects the decompression behaviour of the CO_2 stream[23] and this should be taken into consideration when considering methods to avoid running shear fracture[30].

g The presence of "non-condensables" CH_4, N_2 and H_2S can affect the solubility of water in the CO_2 stream.

h O_2 content to be such that it does not promote acids formation, solids formation and corrosion that adversely affect the operational integrity of the pipeline over the design lifetime, noting that a much lower level of O_2 can be required to avoid unwanted downstream impacts.

i The Weyburn pipeline has 9 000 ppmv of H_2S[58], noting that the CO_2 is dry (<20 ppm)[55], and that the oilfield into which the CO_2 is being injected is already sour.

j The level of impurity required to cause CO_2-CO cracking under pipeline operating conditions is not yet known. However, it has been confirmed that in order for cracking to occur, water needs to be present and that the presence of O_2 enhances the susceptibility to cracking.

k Health and safety impacts of individual impurities within the CO_2 stream are only relevant if their concentration is such that the combined toxic harmful effect of the impurities is greater than the CO_2 itself. The limitations on harmful toxic substances in the CO_2 composition should be specified such that the harm criteria are determined by exposure limits for CO_2 rather than the other harmful toxic compounds, i.e. the permissible level of an impurity can be arranged such that, in the event of a severe uncontrolled discharge, the harmful toxic effect of CO_2 dominates that of the impurity; hence, the former is not relevant, as the recipient would already be affected by the CO_2. It should be documented that the combined hazardous effects have been properly taken into account including the partitioning of impurities between the gaseous and dense phases, noting that toxic components do not necessarily act separately or independently. For examples, see References [61] and [63].

l The presence of H_2S in the CO_2 stream can promote corrosion at lower water levels than in pure CO_2[51].

m STEL: Short-term Exposure Limit, the acceptable average exposure over a short period of time, usually 15 minutes as long as the Time Weighted Average is not exceeded.

n There is experimental evidence that even at levels of <50 ppmv of NO_x and SO_x nitric and sulfuric acid can be formed[44].

o Hydrocarbon content should have a dew point such that condensation does not occur within the operational envelope (combined pressure and temperature) of the pipeline.

Table 4.B: ISO standard for CCS systems

4.1.5 A comparison of specifications

	ISO-Porthos* Concentration [%vol or ppmv]	ATR %vol or ppmv	OCAP %vol or ppmv	ROAD %vol or ppmv	SMR %vol or ppmv	Dynamis %vol or ppmv
CO_2	≥ 95%	> 99%	> 99%	> 99%	> 99.9%	> 95%
H_2O	≤ 50 ppmv	< 50 ppmv	≤ 40 ppmv	< 150 ppmv	< 50 ppmv	200 ppmv
H_2	< 1%	< 0,5%				≤ 4%*
N_2	< 2%	< 20 ppmv				≤ 4%*
Ar	< 1%					≤ 4%*
CO	< 0,2%	< 350 ppmv	≤ 750 ppmv		< 10 ppmv	2000 ppmv
O_2	≤ 40 ppmv	?	< 30ppmv	< 70 ppmv	< 10 ppmv	10 ppmv
H_2S	≤ 20 ppmv		≤ 5ppmv			200 ppmv

SO_x	≤ 50 ppmv					100 ppmv
NO_x	≤ 50 ppmv		NO - 2,5 ppmv NO2- 2,5ppmv			100 ppmv
C_{2+}	≤ 2,5%	< 1 ppmv				
CH_4	< 1%	< 540 ppmv			< 0.1%	≤ 4%* (all together for non-condensable gases)
Total hydrocarbons			< 1200 ppmv			
Total aromatic hydrocarbons			< 0,1 ppmv			
Ethanol		< 10 ppmv	< 1 ppmv			
Methanol		< 100 ppmv				
Acetaldehyde & ethylacetaat (together)			< 0,2 ppmv			
COS			< 0,1 ppmv			
CS_2			< 1,1 ppmv			
Ethylene			< 1 ppmv			

Table 4.C: A summary of theoretical and practical CO_2 Specifications under consideration for developing a general specification for the port of Rotterdam.

Transporting the CO_2 between emitter (capture) source and storage facility requires a CO_2 stream with a high degree of consistency across the whole CCS chain. As the quality of the CO_2 captured from multiple sources, will inevitably differ from each other, it is necessary to define a specification which can be used for designing future CO_2 capture plants.

When comparing the specification of CO_2 produced by the ATR to the OCAP specification , it can be seen that this does not completely comply. In case Porthos applies ISO spec there should be no problem. The conservative choice at this time is to select the OCAP spec for the H-vision plant which is achievable with an ATR but may require additional facilities.

Porthos will confirm its final CO_2 specification in in the course of 2019.

4.2 Risks of CO_2 transport and storage

To develop blue hydrogen requires the transport and storage of the CO_2, with the associated risks of those processes. This section briefly discusses the key risks associated with a) the development of a transport and storage network, b) CO_2 transport and c) CO_2 storage.

4.2.1 Risks of developing CCS infrastructure

The assumption made in this section is that H-vision CO_2 is transported and stored through an existing network (or networks), rather than through a dedicated H-vision network. The Porthos consortium in Rotterdam is developing such a network; the results presented in Section 7.1 (most appropriate storage sites) of the main report provide a view of a potential upscaled Porthos network that can handle H-vision CO_2 in addition to CO_2 from other industrial sources in the Rotterdam port area.

This approach reduces the risks for H-vision associated with developing and operating a transport and storage network. While a large-scale, multi-user network for CO_2 represents a new development for The Netherlands (elsewhere such networks have been in operation for decades), the Porthos consortium can be expected to have resolved the risks involved prior to the start of operating the network.

Table 4.D gives a concise register of risks related to the development of a transport and storage network. Included in the table are risks associated with the dependence on the Porthos consortium for developing the network, rather than designing a H-vision network. It is understood that in many cases, the Porthos consortium can be expected to lead the resolution of risks, as first-mover. However, it will be beneficial for H-vision to keep in close contact with Porthos to ensure risks resolution, to ensure inclusion of H-vision capacity requirements in the Porthos network design and to support Porthos in discussions with the relevant authorities.

Risk	*Consequence*	*Mitigation*
Porthos network not available for H-vision CO_2 or has not been constructed	H-vision to develop a dedicated network or choose for shipping, increased costs and delay of growth of blue hydrogen	Keep close contact with Porthos consortium
Capacity Porthos network insufficient for H-vision CO_2	Porthos network to increase capacity – doubling pipelines, increased costs and delay of H-vision	Keep close contact with Porthos consortium and convince Porthos of realistic H-vision CO_2 volumes that can be anticipated
Porthos tariffs higher than forseen	H-vision concept becomes more expensive	Early discussions with Porthos; provide clarity about expected volumes from blue hydrogen
Transfer of liability to Porthos not regulated or possible	Significant barrier to capture operators to capture CO_2.	Support Porthos in lobby to the government to find a solution
Permits not in place or impossible to obtain	Porthos network and H-vision concept delayed	Close contact with authorities to explain concept, scope and intentions
Public opposition against CCS	Delay or even postponement of both Porthos and H-vision projects	Involve public opinion in early stage, stakeholder management

		Ensure support from national and regional governments and of Port Authorities
Lack of willingness to support or even a ban on CCS by Dutch authorities	Cancelling of Porthos and H-vision projects	Organize lobby and include EU policies
Variability in H-vision CO_2 supply too large for Porthos system	Large capacity to be secured in Porthos sytem (increasing H-vision cost) or only transport and storage of part of the H-vision CO_2	Install surface buffer to provide peak-shaving and to create stable flow to Porthos system

Table 4.D: Concise risk register for CO_2 infrastructure development.

Risk – variability in supply of CO_2

The forecasted production of hydrogen is variable as the flow consists of a baseload for the replacement of refinery gas and flexible flow needed for the use of hydrogen in the energy market. The need for flexibility is strongly dependent on a combination between supply and demand patterns and the weather. The current plant is designed to have the ability to scale up or down to accommodate for the varying hydrogen demand. As a result, the production and capturing of CO_2 is also very volatile. During “power production” the hydrogen and CO_2 production is approximately 2 times as high (~125%) as during the Base Load production (~62%). As a result, the flow rate during power production would be ~880 tons per hour and during base load production ~430 tons per hour whilst the average production rate for 6 MTPA CO_2 would be ~685 tons per hour. One of the potential risks in this project is Porthos not being capable of handling such big flow differences and needing a more stable supply of CO_2.

Mitigation

During the next phase of the project the potential for a balancing (tank storage) facility should be investigated to provide peak shaving ,enabling a steady flow to the transport and storage facility. Such a facility will enable H-vision to supply a steady flow to Porthos and reduce the required peak-capacity towards Porthos. During power production the facility would be used to temporarily store CO_2 and reduce the flow to the average 685 tons per hour and during base load production the CO_2 from the facility can be withdrawn to reach again the flow of 685 tons per hour, therewith providing a steady flow.

As a next step to determine the balancing requirements it is necessary to look into the options for line packing, tank storage and Porthos flexibility in order to find the optimum for a stable CO_2 supply.

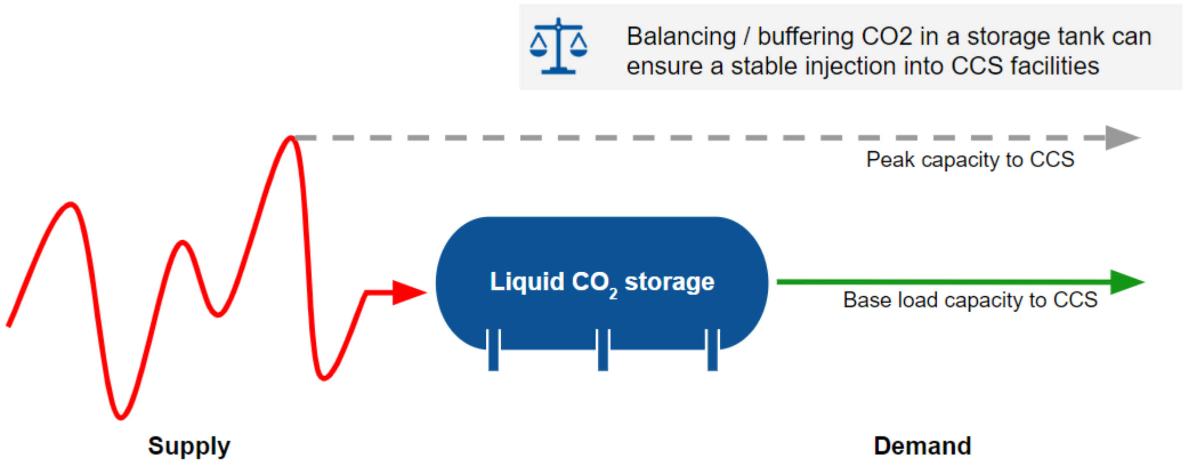

Figure 4.B: Illustration of a surface buffer to equalize CO_2 output.

4.2.2 Risks of CO_2 transport

Transport of CO_2 is common practice, both worldwide and in The Netherlands. The OCAP network near Rotterdam transports CO_2 from sources in the Rotterdam Port to greenhouses; the network operates at a pressure of around 20 bar. A pipeline operating at similar pressure or higher would be needed to connect industrial CO_2 sources to an entry point to the offshore network at the west end of the Second Maasvlakte; this would be part of the collection network of Porthos.

The offshore high-pressure network envisaged for H-vision CO_2 is a new development in The Netherlands. A concise list of risks associated with CO_2 transport are listed in Table 4.E. As in the previous section, it is emphasized that most of these risks are common to both Porthos and H-vision; some of the risks will have been minimized once the Porthos network starts operations.

Risk	*Consequence*	*Mitigation*
Risks of ruptured onshore pipelines	Leakage of CO_2 (emission credits to be handed back), loss of performance, impact on HSE	Use existing expertise and codes of practice in designing and constructing pipelines; use existing pipeline corridor in the Port for collection pipeline
Risks of ruptured offshore pipelines	Leakage of CO_2 (emission credits to be handed back), loss of performance	Use existing expertise and codes of practice in designing and constructing pipelines
Increase in demand for transport capacity faster than expected	Lack of performance, possibly loss of support for H-vision concept	Close cooperation with stakeholders and potential ATR operators and other industrial suppliers
Increase in demand for transport capacity slower than expected	Overcapacity in system; H-vision concept more expensive	Close cooperation with stakeholders and potential ATR

		operators and other industrial suppliers
Permits not in place or impossible to obtain due to conflicts with other usage of North Sea space	Porthos and H-vision delayed or more expensive due to the use of more distant stores	Continuous close contact with authorities
Different emitters could choose different ways of transport	Non-clarity on transport could lead to claims	Ensure clear scope to all stakeholders

Table 4.E: Concise risk register for CO_2 transport.

4.2.3 Risks of CO_2 storage

The risks of storing CO_2 into the locations identified in section 7.1.3. (candidate storage fields) of the main report are considered to be minimal. Data availability and therefore the level of knowledge of these fields is high, following decades of gas production, and the fields are proven to be gas tight reservoirs. Three main geological or technical risk categories are often discussed:

1) Leakage through the sealing formation ('caprock'). The sealing formation has kept natural gas within the gas field for geological time; proven caprock for natural gas is likely to be a suitable caprock for CO_2 as well. Final reservoir pressure is likely to always be below original reservoir pressure and hence below pressure of surrounding formations.
2) Leakage across or up faults. In the Dutch subsurface, natural gas typically collects in reservoirs bounded by faults. The stability of faults during production of natural gas and subsequent injection of CO_2 must be studied for each field. Generally, CO_2 injection and the associated pressure increase in the reservoir towards original reservoir pressure stabilizes faults.
3) Leakage in wells, inside or outside casing and tubing. Wells, finally, are associated with the highest risk of CO_2 migration out of the storage reservoir, as they represent punctures in the caprock. However, experience, tools and technology from the oil and gas industry is available to create and closely monitor fit-for-purpose CO_2 injection wells. There will always be cement outside the casing inside the well which will prevent CO_2 leakage and certainly minimize leakage rates if any leakage occurs. Inside the casing the tubing and other equipment is designed to prevent leakage. When CO_2 injection is complete the casing will be cemented shut leaving no leakage path.

These risks can be reduced to ALARP(as low as reasonably possible) level through careful injection management and design or re-design and ultimate closure of the injection facilities.

It should be emphasized that CO_2 transport and storage is well embedded in European law, the CCS Directive, and national law, in the Mining Act, which contains a literal transposition of the CCS Directive. The Dutch Mining Act prescribes detailed site characterization for a storage permit and requires detailed risk management, monitoring and corrective measures plans to be available prior to the start of injection. During injection the activities and security of storage are overseen by the competent authorities (State Supervision of Mines, SodM).

Table 4.F presents a brief list of storage related risks. Detailed risks related to storage, such as those related to wells, faults and caprock as discussed above, are taken together and fall under the risk 'leakage out of the storage reservoir'.

Risk	*Consequence*	*Mitigation*

Leakage out of storage reservoir	1. Operator takes planned corrective measures. In an extreme case abandon site, develop new site, loss of public support for CCS 2. Hand back emission credits	1. Careful site selection, design and operation (monitoring) 2. Ensure government underwriting of this risk, or arrange insurance solution
Storage capacity proves smaller than expected	Earlier development of new site or sites; loss of performance; loss of industry support	Careful site selection, design and operation (monitoring)
Financial security requirements under permits penalise developers for very unlikely leakage events No or very expensive insurances against these events	High storage tariffs	Early discussions between government and operators to find solution until large-scale CCS has developed
High intermittency of CO_2 supply causes damage to storage facilities	Loss of performance, down time for repairs, potentially move to new storage site	Design robust transport and storage system; include proper requirements in supply contracts

Table 4.F: Concise risk register for CO_2 storage.

4.2.4 Conclusion

The risk registers presented in the previous sections contain a selection of the risks associated with the development and operation of CO_2 transport pipelines and subsurface storage reservoirs. From the point of view of H-vision, most, if not all, of these risks can be assumed to have been resolved by the Porthos consortium by the time blue hydrogen produces the first H-vision CO_2.

As a first mover in CO_2 transport and storage, Porthos will have to resolve a number of key issues with CO_2 suppliers, transport and storage operators and local and national governments, well before the start of operations of the network. There will be an important role for H-vision in supporting Porthos, adding weight in the discussions and negotiations to ensure an outcome that is positive for the development of both Porthos and H-vision concepts.

4.3 Transfer of title and risk (liability) of CO_2

This section is to provide a general view on the transfer of title and risk of carbon dioxide in the CCS chain (from source to sink). A definition of the entire CCS chain is necessary to identify the points where title and risk can be transferred from one company to another in the CCS chain.

1. Emitter and Shipper; the company owning CO_2 emissions sources where CO_2 can be captured and compressed before it is injected in the transport pipeline.

2. Transporter; owner and operator of the CO_2 transport pipeline infrastructure, who transports the CO_2 from the injection point of Emitter to an offshore sink (geological storage formation).

3. Offshore platform operator; the company receiving the CO_2 transported to the offshore point of injection, and who injects the CO_2 into a geological storage formation for the storage permit holder.

The transport of CO_2 by pipeline from source to sink is the most likely option. CO_2 will not be transported at scale unless there are sufficient and reliable sources, including a pipeline transport infrastructure as well as sufficient, secure, safe and available long term storage options. These activities will consequently require the establishment of property rights, appropriate regulations governing the long term liability, monitoring, measurement and verification of sites, as well as effective compliance regimes across the CCS chain.

Therefore, H-vision's base case is to make use of the Porthos transport and storage system (T&S) for the transport to and storage in offshore storage facilities off the Dutch coast. H-vision plants will supply the captured CO_2 to the Porthos backbone infrastructure which runs through the port's industrial complex.

Porthos currently envisages both liability and title to be transferred at different separate points in the system. Under the current legal system, the Porthos Transport entity is held liable for leaks or other incidents relating to the CO_2 once the CO_2 molecules have entered the backbone infrastructure. However, Porthos is not allowed to own or take title to the CO_2. Ownership remains with the emitter/shipper. Therefore the Porthos Storage entity will only take over the title of the CO_2 at the Point of No Return (PONR) at the end of the transport facility. At this time Porthos has defined this to be just before the riser pipe up to the offshore platform. An alternative (as envisaged under the CO_2 storage Directive and Dutch Mining Law) would be for title to transfer after the platform, at the wellhead. As such the title of the molecules and the liability have been decoupled whilst in the transport infrastructure which currently includes the onshore pipeline, the compressors station (CS) and the offshore pipeline. Figure 4.C illustrates this.

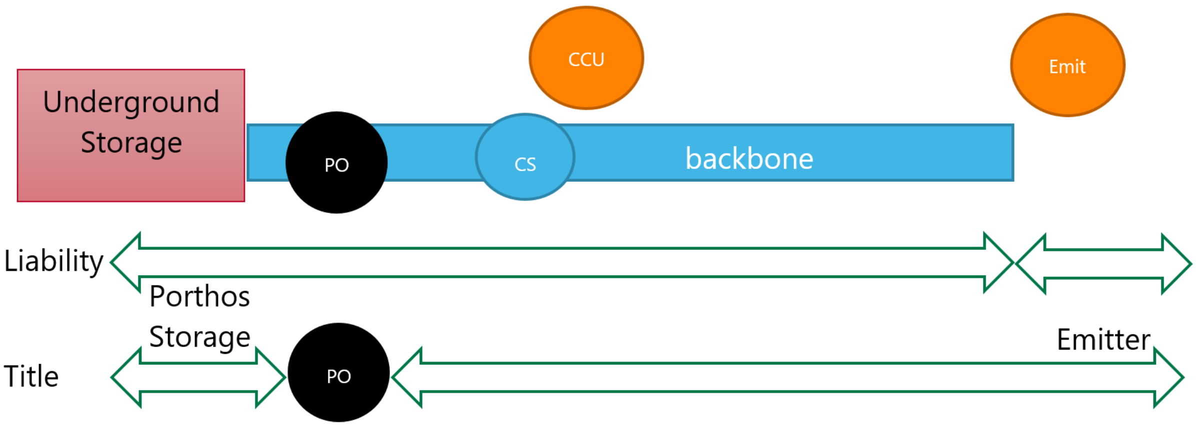

Figure 4.C: The points of transfer of title and liability from Emitter to Porthos Storage Entity.

The implication is that also a 'H-vision entity' supplying the CO_2, would remain holder of the CO_2-title either until the point of no return (at the riser to the offshore platform), or until the CO_2 reaches the wellhead, after which title would be transferred to the Porthos Storage entity.

Shipper Model

In the future it may be possible that a transporter takes over both title and (ETS-) liability of the CO_2 whilst in the backbone but this would require a change of law.

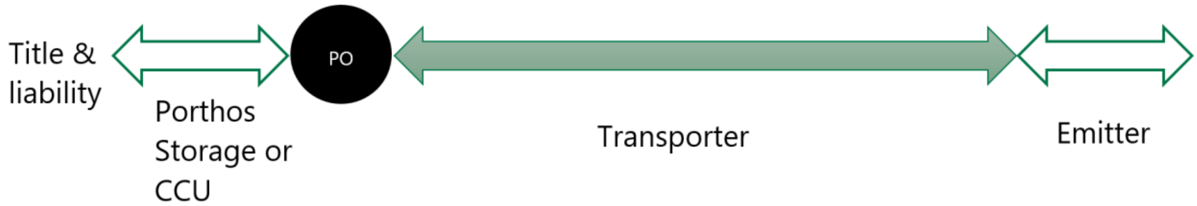

Figure 4.D: Potential future situation for transfer of title and liability

The CO_2 must be permanently stored in order for the emitter to prove that the CO_2 has not been emitted and hence reduce liability to buy and surrender EUA's. Only the storage entity can confirm this. So there will have to be a contractual relationship between the storage operators through the Porthos storage entity and the emitter, unless the Porthos storage entity takes over operatorship of the storage sites.

4.3.1 Discussion of short, medium and long term liability of CO_2 storage

The liability regime for the CO_2, once it has passed the wellhead and becomes permanently stored in the underground fields, is established under the CO_2 underground storage[12] directive and transposed into Dutch Mining Law. The law covers several phases of storage operation; 1) during injection until closure, 2) following closure until demonstrated permanently storage so that responsibility for the field can be transferred to the competent authority, notionally at least 20 years and then 3) after transfer for at least 30 years, unless the competent authority decides and agrees differently on the timeline.

[12] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32009L0031

CO_2 storage is a young industry in Europe, but technology is established and field selection will be rigorous and any leakage from the field once the CO_2 is stored is extremely unlikely. This is particularly true for storage in depleted pressure natural gas reservoirs as the final CO_2 pressure is kept below the original pressure. The surrounding rocks will always be at a higher pressure, keeping the CO_2 in the field. The Directive and the law consider scenarios where the operator is unable to fulfil obligations and the competent authority has to step in early. That is the purpose of the Financial Security (FS) required under each storage permit.

The FS required covers normal oil and gas industry equivalent decommissioning obligations to close the field and make the CO_2 "safe" = permanently stored. The FS considers the case where the Operator is unable to fulfil operations and the competent authority needs to step in and nominate a replacement operator until the permit can be handed over to another operator. In this period the CO_2 will need to be monitored until injection can begin again.

The FS liability requirement goes further however, and considers unplanned events that the industry will consider unlikely. These include CO_2 leaving the storage site and entering the storage complex (migrating to the surrounding rock) which will then require increased monitoring activity. The liability also includes an extreme leakage event requiring the plugging of the leaks following the release of a large volume of CO_2 back to the atmosphere. The design of every project will specifically address all necessary measures to eliminate such a possibility.

Hence the liability is a mixture of 100% certain activities (decommissioning and monitoring) and extremely low probability events (migrating, leakage and subsequent repair) without taking account of probability in the calculation.

Insurance is often proposed to help mitigate the low probability events. The insurance market however, has no background in assessing these risks and is likely to provide only limited coverage and charge high rates. Governments are considering setting up a national or industry fund to be accessed by any operator or competent authority specifically to reimburse the costs of any extremely low probability event that occurs. This is the best way to avoid every storage permit including the requirement to set aside large sums to cover extremely low probability events as though they were certain. Only the banks benefit from that situation. At this time the risk related to the long term liability will be difficult for most private operators to accept.

4.4 Costs of CO_2 transport and storage

The default solution for CO_2 storage is to make use of the Porthos system. The actual costs for CO_2 transport & storage will therefore be determined by Porthos. At this stage Porthos is developing its business case and is not yet able to provide any reference costs for their phase 1. H-vision would supply to the Porthos network in a Porthos-phase 2. The feasibility study for Porthos-phase 2 has not yet been started.

This report includes an analysis of what transport & storage costs might be, based on the cost parameters given in a report by (EBN / Gasunie, 2017) and using TNO's inhouse model.

The results presented in Section 7.1 (most appropriate storage sites) of the main report provide the data for an analysis of the cost of developing and operating a CO_2 transport and storage network. Three development scopes for the supply of additional CO_2 from the Rotterdam port due to hydrogen production were used (see Chapter 4 (solution space) of the main report) to drive network development. These three supply scopes were compared to a 'Porthos-only' base case (without H-Vision). With the implicit assumption that CO_2 captured at hydrogen production facilities would be delivered to an existing CO_2 network, i.e. hydrogen producers as CO_2 suppliers to a multi-user network, the additional network extensions resulting from the increased supply can be attributed to the development of blue hydrogen production capacity.

4.4.1 Cost elements

The cost elements included are listed in Table 4.G and Table 4.H. Most of the elements were taken from (EBN / Gasunie, 2017), which provides cost estimates at a similar level of detail to that considered here.

Two types of platform are considered, export (large) and satellite (smaller). In this analysis, it is assumed that when platforms are older than 40 years new platforms dedicated for CO_2 injection are assumed to be constructed for CO_2 injection; this includes the drilling of new wells. This holds for platforms K15 FB-1, K14-FA-1 and K15-FA-1. In the other cases the platforms are assumed to be modified; these are all smaller (satellite) platforms.

Mothballing (i.e., suspending for later use) of the platforms and the wells is not taken in to account since the period of mothballing is highly uncertain; (EBN / Gasunie, 2017) estimates mothballing costs at around 1 €/tCO_2 stored. Costs associated with monitoring of the CO_2 storage operation are not included; monitoring costs are of the order of 1-2 €/tCO_2 (Zero Emissions Platform, 2011).

To estimate the costs of transport two key elements are taken into account: compression and trunkline cost. Compression cost are taken from (EBN / Gasunie, 2017); in that report energy consumption is based on the 5 MW of compressor power that is needed to compress 1 Mt/a from low (15 bar) to high pressure (100 bar) system; an electricity price of 50 €/MWh is used to compute compression OPEX.

For trunk pipelines two classes specified in the EBN/Gasunie report are used, pipelines with a length of the order of 100 km and of the order of 50 km; the associated CAPEX is listed in Table 4.G. OPEX estimates are based on (Zero Emissions Platform, 2011) and are on the lower side of the range of 2-15 M€/a per pipeline mentioned in (EBN / Gasunie, 2017).

The pipelines to P18 and P15 are assumed to be insulated and therefore an extra cost factor of 1.75 is used (based on ROAD numbers).

Platforms	**(M€)**
Modification existing export platform	15
Operational costs existing export platform (M€/a)	2.5
Decommissioning existing export platform (already paid for)	0
Newly constructed export platform	25
Operational costs new export platform (M€/a)	2.5
Decommissioning new export platform	10
Modification existing satellite platform	11
Operational costs existing satellite platform (M€/a)	2.5
Decommisioning existing satellite platform (already paid for)	0
Newly constructed satellite platform	22
Operational costs new satellite platform (M€/a)	2.5
Decommisioning new satellite platform	10
Wells	
Workover from producer to injector	3
Newly drilled and completed	24
Operational costs (M€/a)	0.4
Plug and abandon new wells	6

Table 4.G: Cost elements related to storage

Compression	**M€**
Compression capex for 1 Mt/a compression plant (M€)	15
Compression opex, 4% of the capex (M€/a)	0.6
Energy consumption (M€/Mt)	2.2
Capex Pipeline 50 km 18 inch (M€)	45
Capex Pipeline 100 km 18 inch (M€)	71
Capex Pipeline 50 km 22 inch (M€)	50
Capex Pipeline 100 km 22 inch (M€)	78
Capex Pipeline 50 km 24 inch (M€)	53
Capex Pipeline 100 km 24 inch (M€)	82
Capex Pipeline 50 km 28 inch (M€)	59
Capex Pipeline 100 km 28 inch (M€)	102

Cost multiplier insulated pipeline	1.75
Opex Pipeline fixed 0.25% van capex (M€/a) Opex Pipeline variable 29% injection rate (4 Mt/a – 14 Mt/a) (based on ZEP, 2011)	0.11 – 0.25 1.16 – 4.06

Table 4.H: Cost elements related to compression and transport.

4.4.2 Results

Table 4.I shows a number of key indicators for the technical costs of storage for the four scopes considered. The base case, without H-vision hydrogen, requires 6 of the depleted fields listed in Section 7.1 (most appropriate storage sites) of the main report to store close to 80 Mt of CO_2. On a zero-discount basis, the technical unit cost of storage is 5.3 €/tCO_2. This cost decreases to below 3 €/tCO_2 in the maximum case scenario, in which up to 10 Mt/a of H-vision CO_2 is added to the 4 Mt/a of Porthos CO_2.

The reason for the lower technical unit cost of storage is the fact that the fields that are to be developed in addition to those used in the base case scenario have larger storage capacity. In the base case scenario, the average amount of CO_2 stored per field is 13 Mt, which increases to 29 Mt per field in the maximum case. This shows that the choice of fields determines the unit cost of storage, rather than the amount of CO_2 to be stored. In other words, the additional CO_2 that H-vision would add to a transport and storage network for industrial CO_2 does not necessarily increase or decrease the cost of storing CO_2.

Table 4.J shows similar results for compression and transport. Unit cost for compression is almost independent of the scale of CO_2 transported case, as the main component is the energy consumption, which scales with the amount of CO_2 transported. It is assumed here that all compression is done onshore; no offshore recompression is included. In contrast, the cost of operating pipelines decreases for larger transported volumes. The unit cost of transport (i.e., not including compression) decreases from 3.2 €/t in the base case to 2.2 €/t in the maximum case scenario. This illustrates the higher efficiency, on a unit cost level, of larger capacity pipelines.

	Base case	*Minimum scope*	*Reference scope*	*Maximum scope*
CO_2 stored (Mt)	78	120	204	288
Cumulative capex (M€)	252	328	354	541
Cumulative opex (M€)	163	189	221	295
Cumulative capex+opex (M€)	415	517	575	836
Technical cost of storage (€/t)	5.3	4.3	2.8	2.9

Table 4.I: Key performance indicators for storage for the four scenarios

Cumulative results	*Base case*	*Minimum scope*	*Reference scope*	*Maximum scope*
CO_2 transported (Mt)	78	120	204	288
Compression capex (M€)	60	90	150	210
Compression opex (M€)	221	338	573	807
Compression capex+opex (M€)	281	428	723	1017
Technical cost compression (€/t)	3.6	3.6	3.5	3.5
Transport capex (M€)	215	215	334	393
Transport opex (M€)	35	93	170	241
Transport capex+opex (M€)	250	318	504	633
Technical cost transport (€/t)	3.2	2.7	2.5	2.2

Table 4.J: Key performance indicators for storage for the four scenarios.

The final numbers on the cost can be found in Section 7.3 (costs of CO_2 storage) of the main report.

5 Annex to chapter 8: Business model

5.1 Risks

5.1.1 Risk Management system

Risk management (RM) is a structured process which helps to prevent or contain the consequences of possible events which, if they occur, negatively impact the objectives of the H-vision opportunity. This opportunity is to enable decarbonisation of the industry through the large-scale production and use of blue hydrogen in the energy supply for the industry in the port of Rotterdam area.

RM is not a stand-alone activity but an integral part of project management and the decision-making process. It should be applied throughout all phases of the H-vision opportunity, although with a different focus, in order to safeguard its objectives and values. It gives confidence to the stakeholders about how the project is being managed.

The RM process also guides the project team how to manage risks and who is responsible for what and when.

Process, organisation and tools

The H-vision risk management process includes the following steps: 1) Identify, 2) Assess, 3) Plan response, 4) Implement, 5) Monitor and re-assess (see Figure 5.A). Three out of the 5 steps have been taken within this feasibility study:

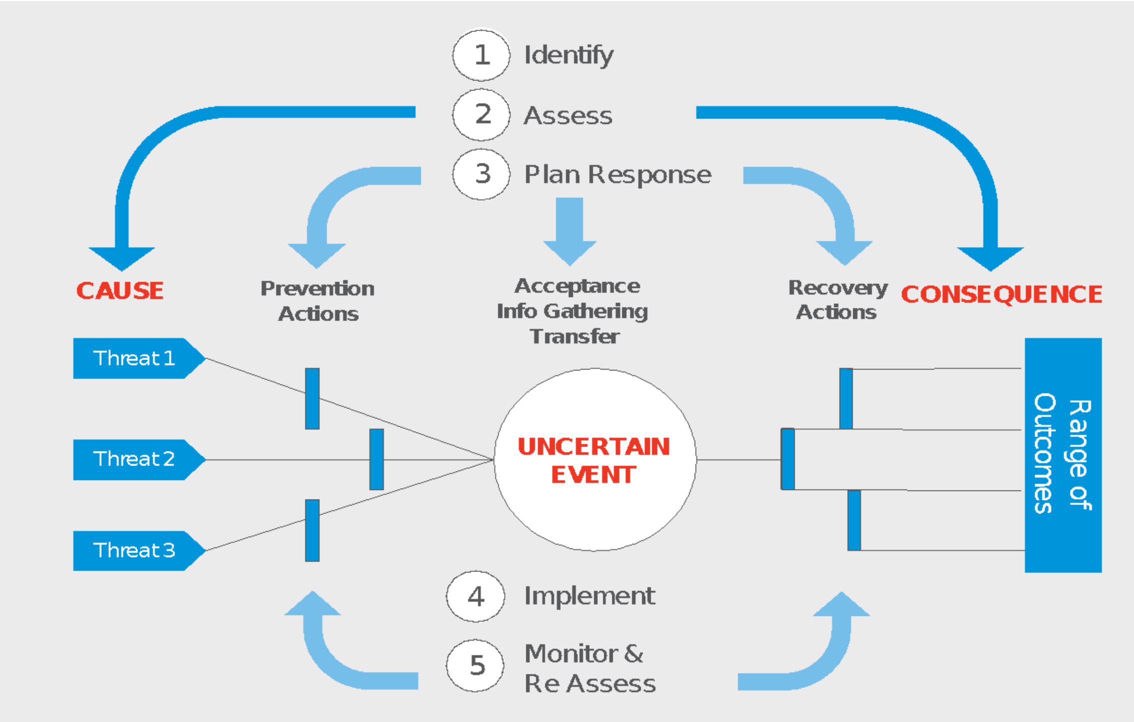

Figure 5.A: The risk management process

1) Identify: We identify the possible future events that could jeopardize the project objectives. By using the TECOP (technical, economical, commercial, organizational and political)framework we make sure that nothing is forgotten and we categorise the risks clearly. At this stage, we identified 68 risks.

2) Assess: These risks are assigned a risk profile ("small", "severe" or "critical") that is based on probability of occurrence and the potential impact on the project. The prioritization of the risks is done with the help of the risk assessment matrix, shown in Figure 5.B.

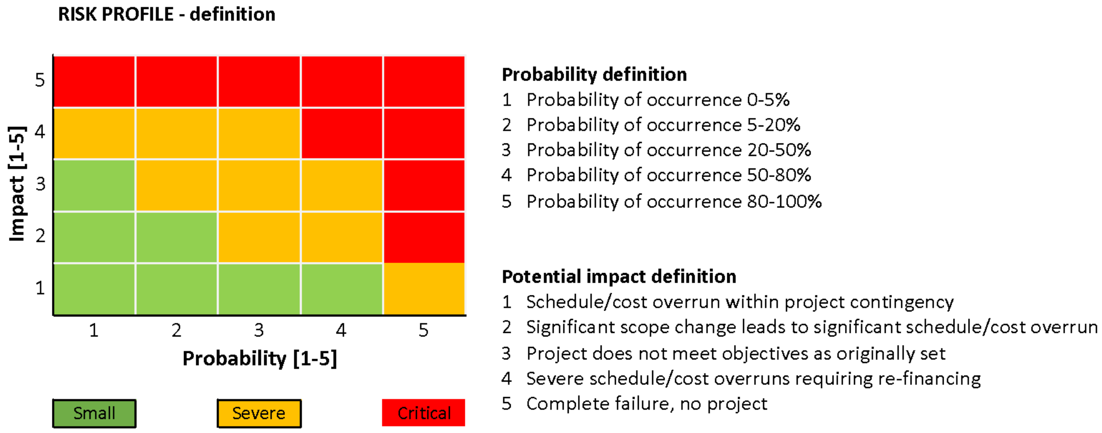

Figure 5.B: Risk assessment matrix and risk profile definition

3) Plan response: Risks are allocated to certain workgroups or persons. The mitigating measures are identified. The response actions can be acceptance, prevention, recovery, information gathering or transfer.

4) Implement: The risk/action owner must implement the agreed risk response and update the status description to reflect the situation as it is. If the risk is sufficiently reduced then some of the response actions may no longer be required.

5) Monitor and Re-assess: The risk owner should monitor and update the assigned risks regularly because the external and/or internal project environment is continuously changing and it may be that responses have been implemented or are found to be less/more effective; changes to the risk assessment/response plan are therefore required.

The 68 identified risks have been summarized in an Excel based live risk register.

5.1.2 Organisational responsibilities

The risk profile categories (small, severe, critical) are articulated at the 'right' level of the H-vision project organisation which means that the mitigation of the 'critical' risks should be explicitly approved and resourced by the H-vision steering- and/or participants boards. The mitigation of the 'severe' risks may be approved and resourced by the project manager. The 'smaller' risks are managed by the workstreams (business, technology, markets, CO_2 transport & storage and strategic stakeholder management) as part of the normal work.

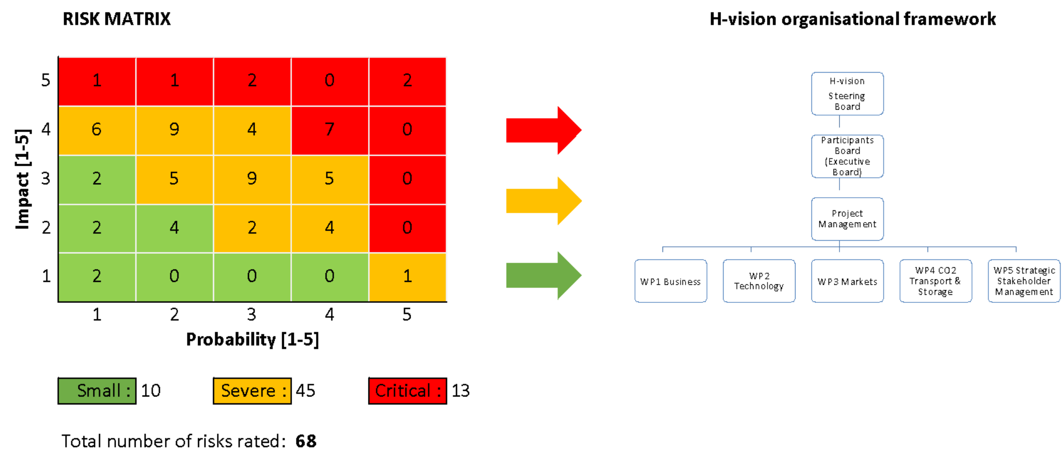

Figure 5.C: Risk assessment matrix and organizational framework

5.1.3 Risk assessment and mitigation

Risk statistics

Derived from the risk assessment matrix, Table 5.A lists the identified risks by project phase.

Risk profile	Project phases			
	2 Assess	3 Select	4 Define	Totals
Critical	5	6	2	13
Severe	10	31	4	45
Small	1	5	4	10
Unrated	0	0	0	0
Totals	**16**	**42**	**10**	**68**

Table 5.A: Summary the H-vision risk register statistics.

Risk table

The critical risks in the various project phases are described in the Risk table below:

5.1.4 Risk table

TECOP Category	**Work Package**	**CRITICAL risk description**	**Mitigation Description**	**Mitigation Project phase**
05. Transport & storage	2. Technology	CO_2 T&S capacity: All capacity in CO_2 transport and storage infrastructure is used by a combination of other industry in Rotterdam,	Investigate alternative CO_2 evacuation routes/outlets including Equinor route; Talk to Porthos	3 Select

		Antwerp and Duisburg.		
11. Life-cycle cost	2. Technology	CAPEX estimate: The total CAPEX is grossly underestimated in the pre-FID phase which has an adverse effect on the project economics	Use an appropriate cost breakdown structure Work with service/equipment suppliers Take into account a sufficiently wide range of CAPEX uncertainty	2 Assess
12. Scheduling	1. Business	Changing economics: Changing economics during the construction or lifetime of the project do no longer support the business case	Validate economic input parameters Stress test project economics against various scenarios Government contracts for difference to control risks Direct pass through costs to clients and price indexing	2 Assess
13. Capacity	1. Business	Macro-economics: Adverse macro-economics results in a waning demand for blue hydrogen and an overcapacity of hydrogen production, reformers	Long term take-or-pay contracts Hydrogen storage for short-term overcapacity Commercial fee to be greater than your fixed charges (O&M, G&A, return on capital)	3 Select
15. Valuation method	1. Business	Government vs private WACC: There is a difference in the economic parameters (WACC) and performance criteria (IRR) of the government vs private sector and the government perceives no financial gap which they need to cover	A difference in WACC is the result of a combination of risk perception and funding potential. Both need to be modelled specifically and well explained to the government to ensure adequate support	4 Define
15. Valuation method	1. Business	IRR of project is seen as too high by government and	NL government to partially accept the project risk e.g. debt	3 Select

		too low for private companies	guarantees etc (see BEIS, UK examples)	
16. Market prices	3. Markets	Low prices CO_2 emission rights : CO_2 market prices are too low to support the economic feasibility and drive investments in the project	Contract for difference on CO_2 prices with Government	4 Define
22. Contract & procurement	1. Business	Lack of commitment: There is a financial gap; industrial entities using blue hydrogen refuse to enter into long term commitments matching CAPEX depreciation timespan of business.	Government financial support/instruments	3 Select
23. Financing & subsidies	1. Business	Project funding: There are no adequate (subsidy) policy instruments in place to fund various project phases (i.e. FEED, execute and operate) or specific installations	Make an inventory of the current EU and NL policies on blue hydrogen. Identify the critical gaps that need to be closed. Pro-actively engage with the relevant EU and NL policy makers	3 Select
33. Partners & interfacing	0. Project Management	Difficult cross-chain integration: The cross-chain integration, including the project-on-project development and the coordination between multiple stakeholders is difficult and leads to scope change and significant delays in project delivery.	Work with the ‘nested-roadmap’ concept that clarifies how multiple projects fit into and align with the top-level overall H-vision roadmap. ‘Nesting’ breaks down complicated opportunities into manageable and understandable components. Put in place an H-vision dedicated project management	3 Select

			organisation (incl strategic stakeholder management workstream) with wide enough mandate to engage and leverage internal and external stakeholders	
41. Government	5. Strategic Stakeholder Management	Emissions reduction % not accepted: Emissions reduction % achieved by H-vision is lower than will be accepted and supported by government	Liaise with NL government asap Design the technical solution and development concept such that it meets the NL government's requirements	2 Assess
43. Communication	5. Strategic Stakeholder Management	Public safety perception: The public perceives that hydrogen in large quantities may not be safe		2 Assess
43. Communication	5. Strategic Stakeholder Management	"Fossil stigma: - Blue hydrogen is linked to CCS - is this what we want? Is CCS an interim solutions and for how long? - Blue hydrogen is produced from natural gas , whilst in the Netherlands we want 'off-the-gas' . What about blue hydrogen wrt Groningen? - Perceived lock-in of blue hydrogen since green hydrogen cannot compete with blue hydrogen; this will not go away and therefore there may be insufficient political support	"Early stakeholder involvement of governmental organisations in particular. Crisp clear communication that blue hydrogen is ultimately an enabler for the (green) hydrogen economy	2 Assess

Table 5.B: Risk table

6 Annex to chapter 9: Project economics

6.1 Economic Model

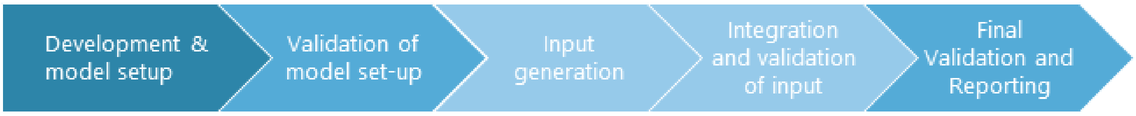

Figure 6.A: Model development process

An internal process with was put in place to guarantee the integrity of the project economics. Validations were done on the model set-up, acquired inputs and the output results. To this end, a process consisting of five steps was carried out.

1. The business case model was designed. The general purpose was discussed, as well as the main metrics and the required inputs to calculate these metrics.
2. Validation of the model design by all the collaborating partners, feedback was accordingly integrated into the model.
3. Input generation by the market and technology working groups. The solution space methodology was used to manage the interface between markets, technology and the business working groups. Experts within these groups made OPEX and CAPEX estimates of the H-vision design and prediction concerning future electricity prices.
4. All inputs were combined in the business case model and an iterative process of consistency validation was performed in collaboration with the technology and market working groups.
5. The entire business case model was validated by the collaborating partners and deemed acceptable for use in this project phase of H-vision. Finally, results were presented in this report.

6.1.1 Model Description

The H-vision project comprises the full and integrated Hydrogen-CCS value chain. This includes the entire supply chain for the hydrogen production as well as the storage, distribution and the end-use of hydrogen primarily as a fuel for high temperature heat and power generation. The capture, transport and storage of CO_2 is also part of the value chain and within the scope of the project. To assess the economic feasibility, yearly energy and cash flows were modelled for the period until 2045, in line with the development concepts and scenario's as presented in the solution space. Figure 6.B gives an overview of the energy and cash flows which were taken into account to model this.

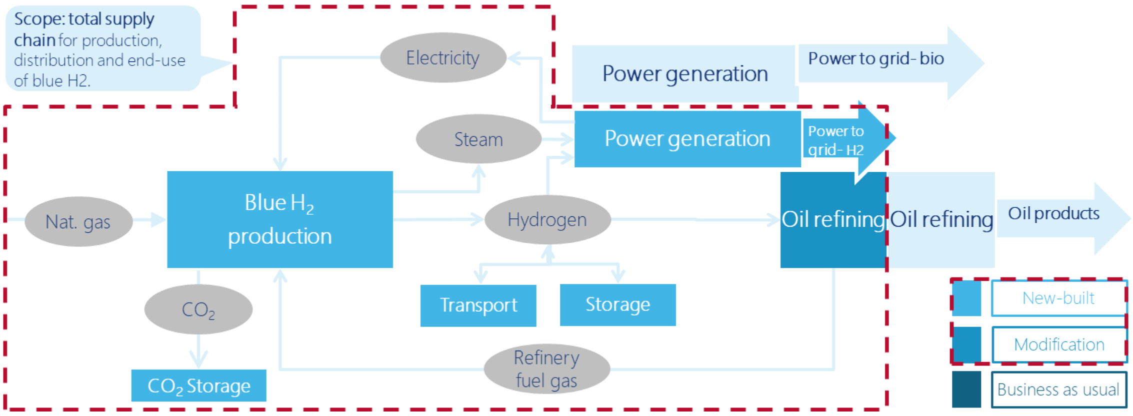

Figure 6.B: Overview of the energy and cash flows which were taken into account in the to model this

The economic model is based on the pre-tax discounted cash flow (incremental to the business-as-usual situation). It comprises the valuation of all incremental costs (CAPEX and OPEX) and all incremental benefits (revenues and subsidies) from a 100% project perspective; this means that the project internal commodity and cash flows between the separate H-vision participants are not taken into account for the time being. In practice this means that for example the price of refinery fuel gas is not taken into account: in the business case only the *additional* natural gas that is required to produce hydrogen with the same energy content as the original refinery fuel gas stream is taken into account.

Reasoning for using the WACC is described in paragraph 5. The financial gap is calculated as the difference between the negative project NPV (without subsidies) and a situation where the project NPV becomes neutral through subsidies. In some cases the required subsidy in order to get the business case NPV neutral is less than 30% of the CAPEX. The required total OPEX subsidy is calculated and then divided based on the tonnes CO_2 avoided. This subsidy scheme is arbitrary. Also other subsidy schemes using (a combination of) CAPEX subsidy, OPEX subsidy and contracts for difference could be used.

6.1.2 Economic performance indicators

Within the business model a wide range of metrics will be calculated to give comprehensive overview of the project economics. Main metrics included were:

- Net Present Value (excluding and including subsidies), defined as the sum of the net cash in-outflows for the project discounted at WACC.
- CO_2 avoidance costs (overall, and in both power production and oil refining), defined as the ratio between the discounted cashflows compared with a reference and CO_2 emission reduction in Mton (compared to the 'do nothing' or 'business-as-usual case), discounted with the WACC. The reference process for oil refining is business As Usual and for the power plant a generic gas fired power plant.
- Value Investment Ratio (excluding and including subsidies), defined as the present value of the future cash flows of the project, divided by the initial investments;
- Delta Levelized Cost of Energy (Δ LCOE, excluding and including subsidies), is the ratio between the discounted cashflows compared to a reference situation and the produced hydrogen, discounted by the WACC;
- Internal Rate of Return (excluding subsidies), defined as the WACC which should be used to get a NPV neutral project;
- The required subsidy, which is calculated as a CAPEX subsidy and an OPEX subsidy.

- Inflation is not included in the model, all prices are given as real and all calculations are done with a real discount rate.

The dynamic nature of the broad macro-economic environment requires a dynamic economic model. The model allows testing the economic feasibility of different development concepts (minimum scope-reference scope-maximum scope) against different scenarios (As Usual-economic world-sustainable world). This enables a comprehensive overview of the financial gap. In the model a choice can be made out of nine possible combinations each made up of one development concept and one scenario. The development concepts influence the level of hydrogen production and demand in the business model. The scenarios influence the prices for electricity, natural gas and CO_2 within the model. Each combination creates a different cash flow, which in turn influences the level of subsidy required and the overall attractiveness of developing the H-vision project. The H-vision base case is defined as the combination between the reference development concept and the economical world. This case portrays a situation where very significant adjustments to the existing refineries and power plants are made (to replace coal, natural gas and refinery fuel gas with blue hydrogen) in a macro-economic environment with strong economic growth and a continuing ambition to meet climate goals. This leads to resource constraints, increasing prices (both commodities and CO_2 certificates) and accelerated development of key technologies (see also Chapter 4 (solution space) of the main report and Annex 1 regarding the solution space). The reference case is deemed as the most likely, creating significant strides in CO_2 emission reductions and will most certainly not cause any regrets.

6.1.3 Assumptions with respect to technology

Blue hydrogen production

Blue hydrogen is produced using a reforming installation. The reference development concept involves the production of blue hydrogen from natural gas (NG) and/or refinery fuel gas (RFG) through a single ATR (Auto-Thermal Reforming) plant at the Maasvlakte. The selection of ATR as the most probable and preferred hydrogen production technology as described in Chapter 6 (technology) of the main report and Annex 3 on technology is comparable with the technology selection for the H21 North of England project. Which is based on criteria such as energy efficiency, CAPEX and OPEX, CO_2 emission reduction, technology and supply chain maturity, reliability for robust security of supply and impact on land use and water resources (Northern Gas Networks, 2018). Three commodities are used as feedstock for the production of hydrogen. Refinery fuel gas, which is provided by the oil refineries. Natural gas, which is purchased at the natural gas market. CO_2 lean electricity from the H-vision power plants is mainly used to drive the air separation unit. The economics take into account the utilization of residual steam from the blue hydrogen production; this creates an optimal energy efficient system and has additional value. Furthermore, it leads to an additional reduction in carbon emissions.

Hydrogen demand

The estimated maximum hydrogen demand in the low – reference - high case is 1.124 – 3.206 – 5.178 GW. The hydrogen production capacity required to meet this demand will be ramped up in 5 years. Baseload demand from industry is essential, because the reforming units that produce blue hydrogen require time to start up and shut down and must therefore be operated continuously. The demand estimate is based on publicly available data for CO_2 emissions and fuel usage and the consultation of various H-vision participants.

The off-take of hydrogen can be part-load, driven by the varying electricity price. Flexibility is required to bridge the gap between hydrogen production and off-take. In the low and reference development concepts this is provided by flexible hydrogen production. The high case takes into account underground storage in salt caverns in the Groningen area.

Transport and storage of hydrogen

Three transport networks are required to connect the blue hydrogen production supply energy to all users. At first, the blue hydrogen production facility requires a connection to the existing natural gas grid. Furthermore, refinery fuel gasses need to be transported to the blue hydrogen production facility. These costs are included in the refinery retrofitting costs. At last, a new hydrogen distribution network should be constructed, for which OPEX and CAPEX estimates are included. H-vision assumes hydrogen transport by pipeline only, since this is the only feasible way to transport the volumes required. The envisaged hydrogen pipelines in the Port of Rotterdam will be limited in length (and hence in pressure drop) and require no recompression as the end use is in fired equipment at low pressure conditions.

Hydrogen storage in salt caverns is included in the maximum development case. To this end, CAPEX and OPEX of both the salt caverns including cushion gas and the required infrastructure were included. A connecting pipeline of suitable capacity to the underground storage facilities in the Groningen area is only taken into account for the high case. The nationwide Hydrogen Backbone infrastructure is not part of the project scope, however the CAPEX of the pipeline connecting to this backbone and the tariff to utilize the backbone is taken into account.

End-use in oil refining

At refinery furnaces, blue hydrogen will be fired instead of refinery fuel gasses. Existing turnarounds will be used to accommodate for the time needed to retrofit the refinery furnaces. This will result in a gradual phasing out of RFG and phasing in of blue hydrogen: it is assumed 50% of the total capacity will be provided for with hydrogen in 2026, increasing with 10%/year, until 100% of the refinery furnaces are fired with hydrogen in 2030.

The end-users of blue hydrogen require modifications to their installations. Retrofitting costs are taken into account, but no additional O&M is assumed. Within the low and reference development concepts only the conversion of installations of the H-vision partners i.e. the Engie and Uniper power plants at the Maasvlakte, the PerGen steam and power plant and the refineries of BP and Shell Pernis are considered. Within the high case the Exxon + Gunvor refineries for RFG replacement as well as natural gas replacement of other nearby potential end-users such as Air Liquide, Air Products, Huntsman & LyondellBasell are also considered. EU emissions trading system (ETS) credits are avoided, due to the reduction in CO_2-emissions. This is taken into account as a revenue stream.

End-use in power generation

In the two power plants, steam and hydrogen are converted to electricity. The power operation is modelled using a fundamental thermodynamic power plant. Three operating modes are modelled: only steam integration with the biomass fired power plant, combined with pre-heating using hydrogen and combined with turbines running on hydrogen. The last two operating modes also take into account the integration of additional steam, due to the additional production of hydrogen. OPEX and CAPEX for these operating modes were provided, according to the development cases. The phasing is equal to the phasing in oil refining.

The steam integration was modelled as a baseload application i.e. 8,760 running hours per year. The hydrogen firing (pre-heating and/or turbines) was modelled to run 5,000 hours per year, assuming that no baseload production is required due to the expected increase of renewable power production. In principle, the power plant is modelled to run on the hours with the highest electricity price, since the anticipated overproduction of renewables cause low electricity prices. In the maximum development case, running hours were monthly averaged over the year due the salt caverns not being able to cover a seasonal pattern.

The electricity price forecasts for the three scenarios: 'sustainable world', 'economical world' and 'As Usual world', are based on the figures presented in Chapter 5 (markets) of the main report and Annex 2 on markets. The forecast run from the year 2025 till 2045, for every hour of the year. The model is attuned so that a choice for the appropriate scenario can be made with relative ease to mirror the current economic situation.

The produced electricity is first used to meet the demand of the blue hydrogen production facility. The remaining electricity is sold at market prices. An upside of 10% is taken into account for trading on the unbalance markets.

CO_2 transport and storage

CO_2 will be transported to and injected in offshore depleted gas fields. It was assumed that the CO_2 will be handled through Porthos as a service to the H-vision partners. Therefore, only an OPEX service tariff for both transport and storage is taken into account. In this tariff buffering of CO_2 due to intermittent CO_2 production is not taken into account. Further research on this topic is required. More information about CO_2 buffering is stated in Chapter 7 (CO_2 storage) of the main report and Annex 4 on CO_2 storage. The CO_2 transport and storage tariffs differ with respect to the scenario: in the As Usual World 30 €/ton is used, while in the Economical World 45 €/ton and in the Sustainable World 22.5 €/ton is used.

The estimated CO_2 capture in the low-reference-high case is 2.2-5.5-9.4 Mtpa. To put this in perspective, the refining sector alone accounts for over 12 Mtpa of CO_2 emissions as stated in the technology report, more than a third of all industrial emissions in the Port of Rotterdam.

6.1.4 Assumptions with respect to finance and markets

The following assumptions are made with respect to finance and markets.

CAPEX

The total CAPEX for the low-reference-high case is estimated at 801 – 1,901 – 2,985 M€ in the As Usual World. The CAPEX differ with respect to the scenario: in the As Usual World prices represent 100% of the CAPEX, in the Economical World 150% and in the Sustainable World 75%. These bottoms-up cost estimates includes the costs for the hydrogen plant, the Blue Hydrogen pipeline network, new hydrogen fired gas turbines, modifications to the existing (PerGen) gas turbines and retrofitting costs of refineries. CAPEX for a NG supply pipeline is not applicable since these costs are carried by the national TSO (Transmission System Operator- Gasunie), instead a NG transport tariff applies that must be paid to Gasunie. The level 1 accuracy bandwidth of the CAPEX estimates is +40%, -20%.

OPEX

The total OPEX for the low – reference- high case is estimated along the following lines. The fixed OPEX such as wages, maintenance & spares etc. were estimated 18 – 43 – 63 M€ per year as stated in Chapter 6 (technology) of the main report and Annex 3 on technology. The variable OPEX for the Blue Hydrogen plant includes the import of NG and electricity, CO_2 emissions and tariff payments for CO_2 transport and storage (€ 30/ton CO_2) are depended on the prices in the particular year. The level 1 accuracy bandwidth of the OPEX estimates is +40%, -20%.

Abandonment

No installation abandonment costs (ABEX) or scrap value have been taken into account in the economics.

Project phasing

The project phasing and timeline is as follows

FID at the end of the Define phase in 2022 (reference year)

- CAPEX spread over 3 years during Execution phase (20%, 50% and 30%) with 1st CAPEX spent in 2023 (year 1, 20%).
- Commissioning of the production installations and 1st hydrogen in 2026 (year 4).
- The operating lifetime is 20 years, starting with commissioning 2026 and ending with the decommissioning in 2046.

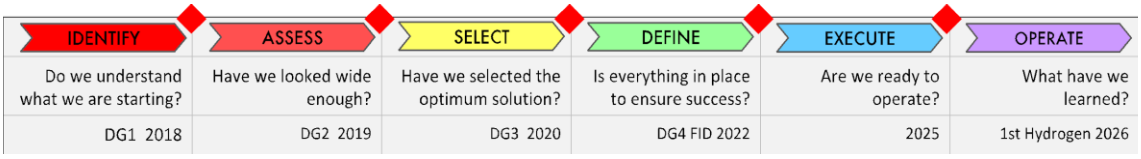

Figure 6.C: Project phasing diagram

Project financing

The project funding will be through equity, debt and government (or EU)-backed financial instruments that are intended to bridge any financial gap that may exist.

WACC

Since the funding structure is unknown at this stage of the project, as are the debt/equity ratio and the cost of equity and debt, and the perceived risk profile of these capital components, a Weighted Average Cost of Capital (WACC) of 3% is selected. This 3% WACC is also assumed in the calculations for the climate agreement (PBL, 2019)[13]. By varying this single parameter it is easy to determine the impact of the risk profile, perceived differently by most parties, on the project feasibility. A higher WACC will tend to increase the financial gap, whereas a lower WACC tends to make the project less reliant on policy instruments for feasibility.

Revenues

The project revenues are based on electricity production, calculated according to the electricity prices and a 10% additional revenue assumed from the imbalanced market. Another important revenue stream is the total monetary value of CO_2 avoidance in terms of CO_2 (ETS) certificates in the refineries and industry.

Merit order

The electricity prices in the model are calculated including the merit order. The merit order is a classification of the order in which power plants turn on as per their marginal costs. The

[13] https://www.pbl.nl/sites/default/files/cms/publicaties/pbl-2019-effecten-ontwerp-klimaatakkoord_3619.pdf

hydrogen fire power plants are expected to be running on the 5.000 hours with the highest electricity prices from the APX market. A mechanism needs to be in place to promote this CO_2 lean power in the market place.

Tax

The project economics is based on a pre-tax discounted cash flow. The potential introduction of a CO_2 tax (on top of the ETS price) is currently a subject of the political debate in the Netherlands. This potential CO_2 tax has not been included in the current model.

6.1.5 Overview of parameters used

Table with an overview of the key (most important) technical, finance and market related input parameters for the low – reference - high case. These inputs are directly coming from the technical data as described in Chapter 6 (technology) of the main report.

	Parameters	Units	Min	Reference	Max
General					
	Operating costs (tariffs) for CO_2 storage	€/ton	15	15	15
	Operating costs (tariffs) for CO_2 transport	€/ton	15	15	15
	[Phasing] Full hydrogen production in	year	2026	2026	2026
	[Phasing] Number of construction years	years	3	3	3
	[Phasing] Slow ramp-up minimum	[%]	1	1	1
	[Phasing] Slow ramp-up years	years	0	0	0
	[Phasing] FID	year	2022	2022	2022
	Power Plant Operating hours with hydrogen	hours	5,000	5,000	5,000
	CAPEX scaling factor - Economical World	[%]	150%	150%	150%
	CAPEX scaling factor - As Usual	[%]	100%	100%	100%
	CAPEX scaling factor - Sustainable World	[%]	75%	75%	75%
	Efficiency CCGT Power plant		56%	56%	56%
Technical					
	Hydrogen Demand	MW	1,124	3,206	5,178
	Natural reformer Capacity	MW output	1,081	2,915	3,888
	Hydrogen output energy efficiency		78%	78%	78%
	Required electricity	MWh_e/MWh_output	5.3%	5.3%	5.3%

	Capture rate		88%	88%	88%
	Unmitigated Emission factor RFG	ton/MWh	0.23	0.23	0.23
	Unmitigated Emission factor NG	ton/MWh	0.21	0.21	0.21
	RFG input	MW input	500	1.170	1.830
	Capital Retrofitting costs Power plant A	M€	-	162.5	192.5
	Capital Retrofitting costs Power plant B	M€	55	162.5	192.5
	Generic O&M Costs Power Plant A	€/MWh	-	2.40	2.40
	Generic O&M Costs Power Plant B	€/MWh	-	2.40	2.40
	Capital Retrofitting costs Refineries	M€	101.6	214.3	389.3
	Capital Investment costs Reformer	M€	616	1,474	2,189
	Fixed O&M costs Reformer	M€/year	18	43	63
	Costs for NG line to Reformer	€/MWh	0.30	0.30	0.30
	Capital costs hydrogen transport	M€	28.3	49.8	72.7
	OPEX costs hydrogen transport	%	1%	1%	1%
	OPEX costs hydrogen transport	k€/year	283	498	727
	Capital costs hydrogen storage	M€	-	-	190
	Operating costs hydrogen storage	M€/year	-	-	7
	Working gas capacity	MWh	-	-	390,000
	Additional transport costs for connection to backbone	M€/year	-	-	1.979
	Emission factor CCGT for comparison	ton/MWh_e	0.38	0.38	0.38
Finance					
	Default WACC	[%]	3%	3%	3%
	Max CAPEX subsidy	[%]	30%	30%	30%
	Number of years OPEX subsidy	years	15	15	15

Table 6.A: Input parameters in the model

6.1.6 Deep dive into the results of the Reference development concept in the Economical World

We have made an in-depth look in the results of the Reference development concept in the Economic World. This was done because in the solution space the reference development concept and the economical world scenario were deemed to be most likely to ensue in reality. The main metrics are shown in the table below.

Metric	Outcome
Net present value excluding subsidies (in billion €)	- 0.65
CO_2 abatement (Mt)	79
Value investment ratio (VIR/Profitability index) including specified subsidies in the model	100%
Value investment ratio (VIR/Profitability index) excluding subsidies	77%
Delta Levelized Cost of Energy (LCOE) excluding subsidies (€/MWh)	8.0
Avoidence costs relative to ETS-price (€/ton)	41
Avoidence costs absolute (€/ton)	**146**
Avoidence costs absolute for powerplants (€/ton)	131
Avoidence costs absolute for refineries and industry (€/ton)	155
Internal rate of return without subsidies (IRR)	1.1%
Internal rate of return including specified subsidies in the model (IRR)	3.0%
Total CAPEX (in billion €)	2.85
Required CAPEX subsidy (in billion €)	0.70
Required OPEX subsidy for first 15 years (€/ton avoided)	0.00

Table 6.B: Main outcomes of the economic model analysis of the Reference development concept in the Economical World

We see that the Net Present Value of the economic model is negative at a WACC of 3%. When 700 M€ of CAPEX subsidy is added, the business case becomes NPV neutral. The total CAPEX is 2.85 M€, so this subsidy roughly represents 25% of the CAPEX. We see that the Value investment ratio is below 100%, since subsidy is required. The avoidance costs are higher for refineries and industry than for power plants, since power plants earn back money using hydrogen on the electricity market and the electricity market is favourable for CO_2-free power production. The project IRR is 1,1%, which means that the business case turns positive when the WACC equals 1,1%.

The business case shows that cashflows are negative during the construction phase and the ramp-up phase, but after 2030 turn positive and eventually lead to substantial positive cashflows. This is shown in the graph below.

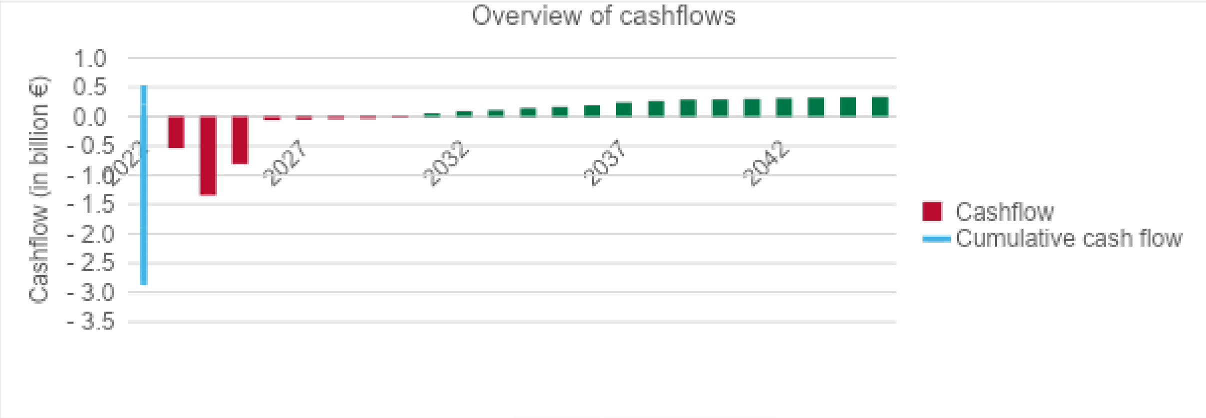

Figure 6.D: Overview of cashflows during the project lifetime

In the economic model a subsidy structure is incorporated whereby at maximum 30% of the CAPEX can be subsidized and an OPEX subsidy scheme for 15 years is present. The total required subsidy is determined in order to get an NPV-neutral business case. Below the required subsidy over the years is shown for this case, whereby we see that only CAPEX subsidy is required and no OPEX subsidy. The peak is in 2024, and only little CAPEX subsidy is spent after 2025 to subsidize late retrofitting costs.

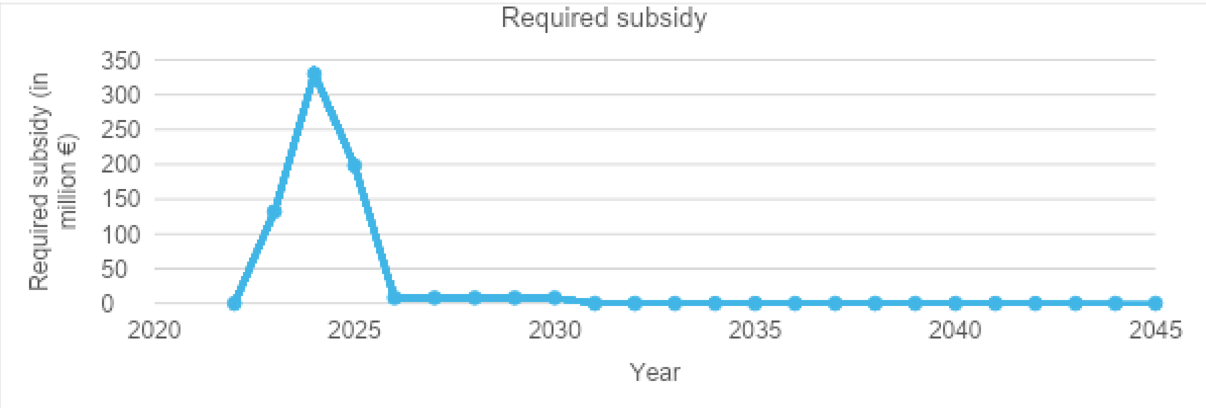

Figure 6.E: Required subsidy during the project lifetime

As discussed H-vision will not immediately run full load, turnarounds are expected to accommodate the time needed to retrofit the furnaces. Therefore the H-vision production plant will run at 50% of the maximum capacity in 2026 and will slowly ramp up to 100% in 2030. This leads to an increasing CO_2 reduction from 2,2 to 4,4 Mt per annum from 2026 till 2030. In the figure below the CO_2 reduction per year is shown.

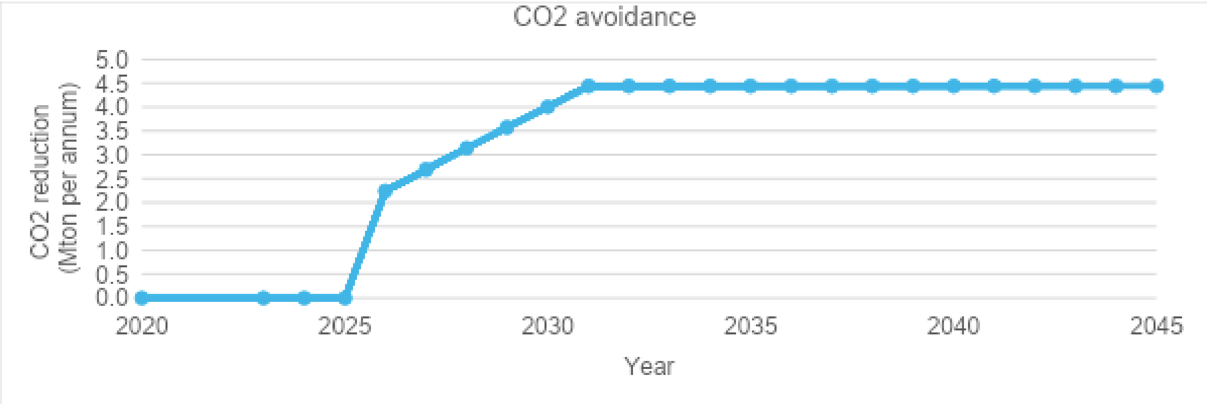

Figure 6.F: CO_2 avoidance per year during the project lifetime

The yearly CO_2 avoidance in this graph ramps up to 4.4 Mtpa, whereas the estimated CO_2 capture is 5.5 Mtpa.

6.2 Sensitivities

In order to increase the credibility of the business model a number of sensitivity analyses were made on the reference case (i.e. the reference development concept in an 'economical world' scenario). Within these analyses the effects of changing a single basic input parameter will be tested.

6.2.1 WACC analysis

The WACC is recognized as one of the most critical inputs in strategic decision-making. The government and private parties may have diverging views on a business case with respect to the WACC. In order to make our estimates comparable with the calculations made in the climate agreement and various PBL studies, we calculate with a WACC of 3%, far below the values typically seen in industry for purely commercial projects. It could be that the government perceives no financial gap which they need to cover due to the application of a low WACC. While the private sector may assert a high WACC value is required for a risky investment and concludes that a financial gap needs to be bridged. In this sensitivity analysis we show the effect of using a range of WACC values, in the model this analysis is done for every combination of the three scenarios and three cases. In the graph below the required subsidy is shown for the reference case in the economical world scenario.

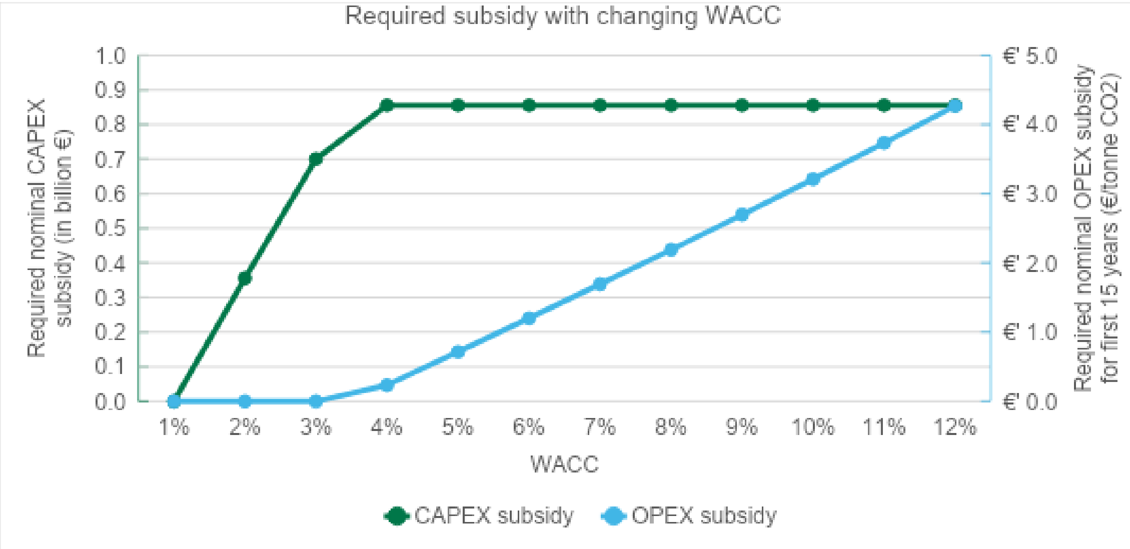

Figure 6.G: Required nominal subsidy as a function of WACC

In the analysis presented we show that at a 12% WACC, which might be reasonable for certain companies, a CAPEX subsidy of nearly one billion euro and an OPEX subsidy of more than 4 €/ton CO_2 is required to make the project feasible, whereas if the WACC is reduced to 1% through the reduction of project risk the project requires no net subsidy over the life of the project. This shows that a higher WACC requires more subsidy, while a lower WACC means public financing or guarantees but leads to lower subsidies. The perceived risk profile of the project is crucial in determining the level of appeal for private companies and external investors to invest in the project.

Along with the required subsidy we have also analysed what is the effect of changing the WACC on the Net Present Value and on the avoidance costs, which are shown below.

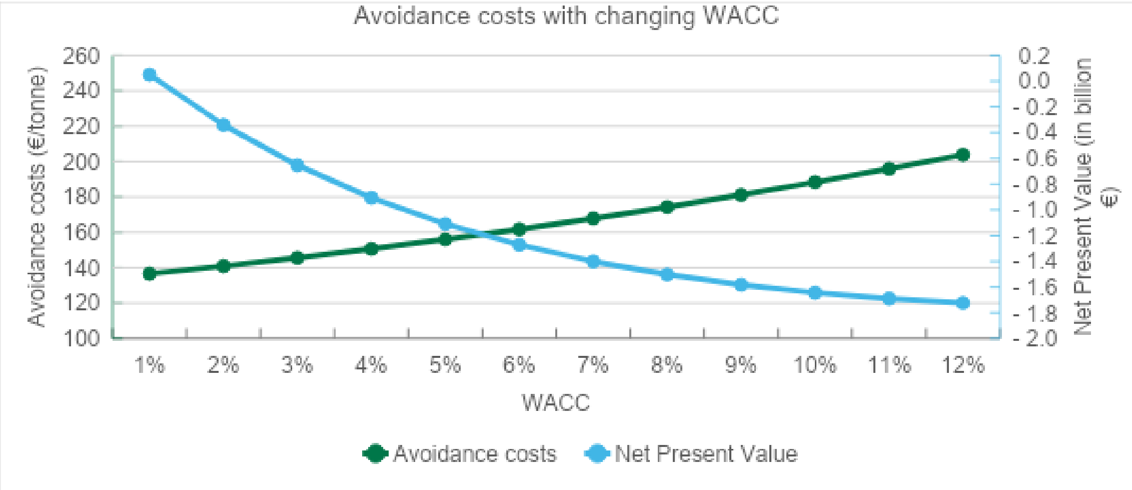

Figure 6.H: Net Present Value and avoidance costs as a function of WACC

From the graph we can conclude that with a WACC below 2.2% the business case is positive without subsidy. The Net Present Value decreases rapidly when a higher WACC is used. The avoidance costs increase with an increasing WACC from 137 €/ton to over 204 €/ton.

6.2.2 Construction time

Contingency in construction time is embedded in model to anticipate delays. The probability that there are delays in construction and/or retrofitting is not high, but are present. For this reason a sensitivity analysis is performed to estimate the effects of the construction time on the total CO_2 avoided and the related avoidance costs.

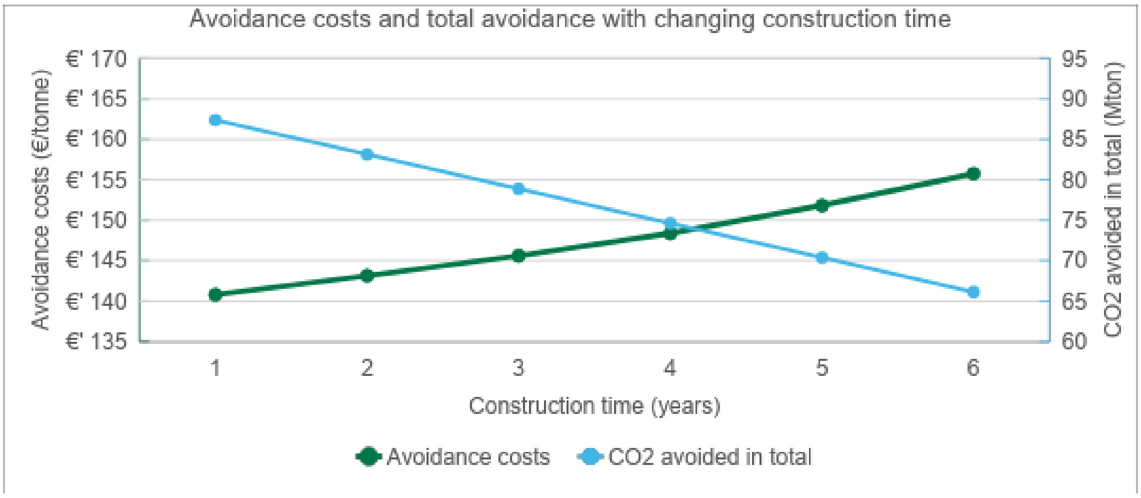

Figure 6.I: Avoidance costs and total avoidance as a function of construction time

The total CO_2 reduction decreases when the construction time increases, since less time is left till 2045 (the end of our business case) to reduce CO_2. We see that the avoidance costs increase with an increasing construction time, mainly due to the fact that the same CAPEX is used for less CO_2 reduction. This means it is required to ensure a fast ramp-up and a short construction time.

6.2.3 Changing CAPEX (75%-200%)

In order to check the sensitivity with respect to the CAPEX estimates, we have performed a sensitivity analysis for the reference development concept in the economical world. The large dot in the figure marks the estimate that is used in the economical world scenario (150%, see Solution

Space). In the sustainable world scenario the CAPEX estimates reduce to 75% and in the As Usual world the CAPEX estimates are accurate with 100%.

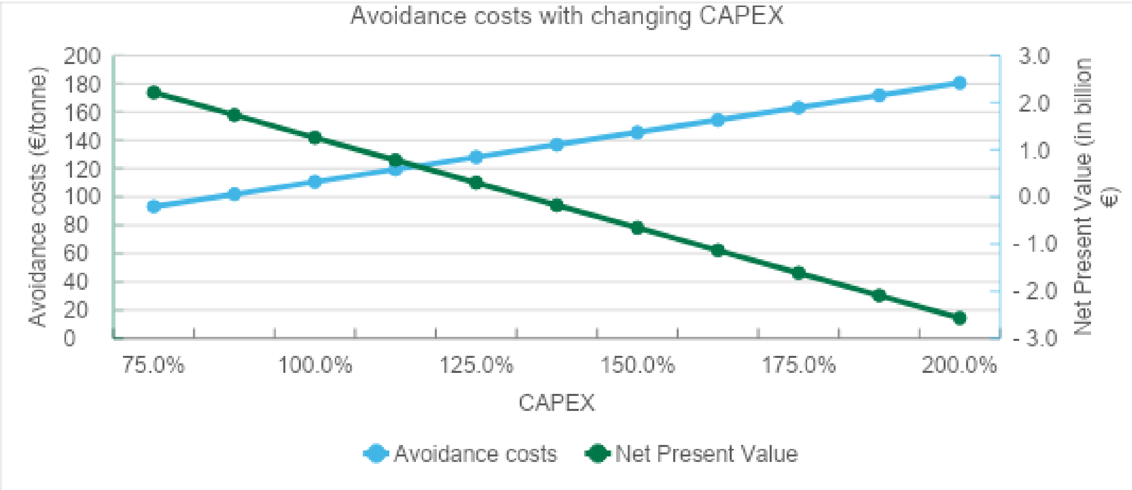

Figure 6.J: Avoidance costs as a function of required CAPEX

From the results we see that the avoidance costs increase rapidly with the CAPEX. An overshoot of the CAPEX estimate is very realistic. The CAPEX could be 200% in the economical world, instead of 150% of the estimate. This would have a large negative effect on the Net Present Value and will increase the avoidance costs.

6.2.4 Conclusion on sensitivities

From the sensitivity studies we conclude that the H-vision economic model is very sensitive with respect to WACC and the CAPEX estimate, but is not very sensitive to the construction time.

6.3 Comparing alternatives

6.3.1 Criteria for comparing alternatives

These criteria followed from in-depth discussions and expert judgements amongst H-vision partners.

Technical criteria consists of the technology readiness level (TRL) and the (capture) efficiency. Blue hydrogen has a high technology readiness level, enabling a short-term Mton scale carbon reduction. The efficiency reflects the additional energy required to run the H-vision reforming plant and auxiliary systems, such as compressors.

Economic criteria consist of the cost of production and the CO_2 abatement costs. Both criteria are a measure of the cost-effectiveness of the carbon reductions, expressed in respectively the energy production and the carbon reduction.

The system integration criteria reflect to which extent the alternative fits within the energy system. Based on existing natural gas supply chain, blue hydrogen can be a large scale solution on the short term. The criteria ‘Volume/capacity’ and ‘Availability’ reflect whether the alternatives are available at large scale, and whether the solution is scalable. The criterium ‘Infrastructure & installations’ indicates how much infrastructural changes are required for the alternative. Furthermore, H-vision is a total solution for either a continuous process, or a process with market-driven running hours. The criteria ‘Intermittency’ and ‘Flexibility’ indicate whether the alternative can meet this prescribed demand as well. Finally, H-vision is in the position to kick-start the hydrogen economy. The criterium ‘Hydrogen Economy Enabler’ indicates whether an alternative supports the hydrogen economy. The criterium ‘Synergy with blue hydrogen’ indicates whether the alternative could possible work complementary to H-vision, or supplement H-vision.

Political and societal criteria reflect to which extent political support is expected for the decarbonization route considered. ‘Stakeholder complexity’ and ‘Public support’ are criteria being used.

For each alternative, the criteria which are most distinctive are presented below. These criteria are scored on a three-point scale, reflecting whether with respect to this criterium the alternative is unfavourable (scored red), less favourable (scored orange) or favourable (scored green). An motivation for the score given is presented afterwards.

6.3.2 Comparison tables

These comparison tables are for the technologies mentioned in Section 9.2 (comparison with alternatives) of the main report.

Main criteria	**Green Hydrogen current**	**Green Hydrogen long term**	**Blue hydrogen current**
Volume/capacity			
Infrastructure			
Technology readiness			

Cost of Production			
Hydrogen Economy Enabler			
	Unfavourable	Less favourable	Favourable

Table 6.C: Qualitive comparison between blue hydrogen and green hydrogen

Main criteria	Biomass	Blue hydrogen	
Availability			
Infrastructure & installations			
Intermittency			
Synergy with blue hydrogen			
	Unfavourable	Less favourable	Favourable

Table 6.D: Qualitive comparison between blue hydrogen and biomass

Main criteria	Green P2Heat	Blue hydrogen	
Synergy with blue hydrogen			
Intermittency			
Infrastructure			
	Unfavourable	Less favourable	Favourable

Table 6.E: Qualitive comparison between blue hydrogen and green Power-to-Heat

Qualitative comparison criteria	Post combustion CCS	Blue hydrogen	
Flexibility			
CO_2 avoidance costs (€/ton)			
Volume / capacity			
Carbon capture efficiency			
Political / societal			
	Unfavourable	Less favourable	Favourable

Table 6.F: Qualitive comparison between blue hydrogen and post combustion CCS

Main criteria	Electricity Storage in batteries	Blue hydrogen
Volume/capacity		
Infrastructure and installations		
Stakeholder complexity		
Public support		
	Unfavourable	Less favourable	Favourable

Table 6.G: Qualitive comparison between blue hydrogen and electricity storage in batteries

6.4 Comparison with redox flow batteries

This part compares the blue hydrogen with the storage of surplus electricity in batteries, specifically in redox-flow batteries. Batteries can also provide flexibility to the electricity grid.

For this comparison, redox flow batteries are considered due to their ability to store energy for longer than 3-4 hours. Lithium Ion batteries, despite being technically advanced, are only suitable for short term storage applications like FCR (Frequency Containment Reserve) and mobility applications (phones, cars, etc.). Redox flow batteries are more suitable for stationary applications and longer term (up to 24 hours, but technically not limited) storage. Therefore, the characteristics of redox flow batteries are quite similar to those of the dispatchable power plants.

Redox-flow batteries look very promising to contribute to more flexibility in the electricity system, due to the following characteristics:

- The ratio of storage power / capacity is flexible (unlike Lithium ion batteries, where this is fixed);
- Redox-flow batteries hardly degenerate over time and therefore the lifetime of redox-flow batteries is long (over 10.000 cycles, compared to 1.500-2.000 for Li-Ion);
- This lifetime is independent of the depth of discharge, leading to lower storage costs per kWh (LCoS);
- Redox-flow batteries do not suffer from self-discharge neither explosion risk and thermal runaways.

Main criteria	Electricity Storage in batteries	Blue hydrogen
Volume/capacity		
Infrastructure and installations		
Stakeholder complexity		
Public support		
	Unfavourable / Less favourable	Favourable

Table 6.H: Qualitive comparison between blue hydrogen and electricity storage in redox flow batteries

Volume/capacity – the demand for adaptable capacity is of another magnitude than the required flexibility

In the Dutch Draft Climate Agreement (Klimaatberaad, 2018), several energy sources are mentioned as possible candidates to generate the 15-17 GW adaptable capacity needed. Large-scale electricity storage is also explicitly mentioned.

Vanadium based batteries have the largest scale, but the electrolyte is not secure and sustainable. There are advanced plans to install two 100MW/400MWh Vanadium based flow batteries in China. These world's largest batteries provide power during peak-hours of demand, enhance the grid stability and, in case of emergency, deliver electricity during black-start conditions. The batteries are expected to come online in 2020. There are issues, however, on the availability of Vanadium. These issues are environmental issues on the mining of Vanadium and a substantial market price volatility.

On the other hand, hydrogen-bromide-based batteries have a secure and sustainable supply, but are not sufficient in scale yet. Hydrogen-bromine-based batteries are currently developed in the Netherlands. Bromine is cheap and widely available. Depending on the tank size, storage capacity can be extended and the costs (the levelized costs of storage or LCoS as developed by Lazard (Lazard, 2018)) per kWh are expected to be well below €0,05 per kWh. The technology of these batteries is currently tested for smaller scale applications (50kW/250kWh – 150kW/900kWh). Once these tests prove to be successful, multiples of these modules could serve as the basis for Megawatt scale applications. This is still an orders of magnitude away from the required adaptable capacity in 2030.

Infrastructure/installations – batteries can contribute but not solve the anticipated power grid congestion

Redox Flow Batteries are able to relieve the strain on the electricity grid as mentioned in paragraph 3.2.1. With regards to the volume/capacity argument, it is questionable whether this will solve all capacity issues in the case of massive electrification by the industry. Leadtime to install these large scale batteries are expected to be shorter than upgrading the network.

Due to the nature of hydrogen Bromine, being highly corrosive and toxic, these batteries need to be installed in a BRZO (Besluit Risico's Zware Ongevallen) environment. This is typically possible in industrial areas like the Port of Rotterdam.

Stakeholder complexity & public supports – Public support for batteries could contribute to blue hydrogen

With regards to the criteria stakeholder complexity and public acceptance, the score of the redox flow batteries is better than those for blue hydrogen. A combination of green electricity, batteries and blue hydrogen in one integrated energy system could lead to a better acceptance for blue hydrogen. In such a system (green) electricity may be used in a maximum range of applications, and beyond that range, blue hydrogen is used.

6.5 Main results with WACC of 6% and 9%

			Minimum scope	Reference case	Maximum scope
	CO_2 abatement	Mton	22.6	48.7	90.6
As Usual	NPV (WACC 3%)	Billion €	-1.4	-2.4	
	Avoidance costs	€/ton	159	122	
	Avoidance costs power plants	€/ton	295	116	
	Avoidance costs refineries	€/ton	133	126	
	Delta Levelized Cost of Energy	€/MWh	22.1	17.3	
Economical	NPV (WACC 3%)	Billion €	-1.2	-1.3	-2.8
	Avoidance costs	€/ton	210	**162**	167
	Avoidance costs power plants	€/ton	370	150	149
	Avoidance costs refineries	€/ton	179	169	175
	Delta Levelized Cost of Energy	€/MWh	19.2	11.91	12.74
Sustainable	NPV (WACC 3%)	Billion €		1.2	1.4
	Avoidance costs	€/ton		94	99
	Avoidance costs power plants	€/ton		81	82
	Avoidance costs refineries	€/ton		102	106
	Delta Levelized Cost of Energy	€/MWh		-1.18	-0.27

Table 6.I: Main results with 6% WACC

			Minimum scope	Reference case	Maximum scope
	CO_2 abatement	Mton	22.6	48.7	90.6
As Usual	NPV (WACC 3%)	Billion €	-1.2	-2.1	
	Avoidance costs	€/ton	175	135	
	Avoidance costs power plants	€/ton	326	131	
	Avoidance costs refineries	€/ton	146	137	
	Delta Levelized Cost of Energy	€/MWh	25.0	19.9	
Economical	NPV (WACC 3%)	Billion €	-1.1	-1.6	-3.0
	Avoidance costs	€/ton	234	**181**	186
	Avoidance costs power plants	€/ton	416	174	169
	Avoidance costs refineries	€/ton	198	186	194
	Delta Levelized Cost of Energy	€/MWh	24.0	16.39	17.06
Sustainable	NPV (WACC 3%)	Billion €		0.5	0.4
	Avoidance costs	€/ton		104	108
	Avoidance costs power plants	€/ton		94	93
	Avoidance costs refineries	€/ton		111	115
	Delta Levelized Cost of Energy	€/MWh		1.46	2.28

Table 6.J: Main results with 9% WACC

6.6 Metrics used

Metric	Description	Definition
Net Present Value	The sum of the net cash in- and outflows of the project discounted at WACC.	$NPV = \sum_{y=2022}^{2045} \frac{1}{1+WACC}^{(y-2022)} cashflow_{H-vision\ business\ case}$
Avoidance costs	Discounted cashflow compared to a reference case divided by the discounted tonnes avoided	$Avoidance\ costs = \frac{\sum_{y=2022}^{2045} \frac{1}{1+WACC}^{(y-2022)} cashflow_{compared\ to\ reference\ case}}{\sum_{y=2022}^{2045} \frac{1}{1+WACC}^{(y-2022)} tonnes_{avoided}}$
Value Investment Ratio	Present value of the future cash flows of the project, divided by the initial investments	$VIR = \frac{\sum_{y=2022}^{2045} \frac{1}{1+WACC}^{(y-2022)} cashflow_{H-vision\ business\ case}}{CAPEX}$
Delta Levelized Cost of Energy (Δ LCOE)	Ratio between the present value of the cashflows compared to a reference case and the produced hydrogen, discounted by the WACC;	$\Delta LCOE = \frac{\sum_{y=2022}^{2045} \frac{1}{1+WACC}^{(y-2022)} cashflow_{compared\ to\ reference\ case}}{\sum_{y=2022}^{2045} \frac{1}{1+WACC}^{(y-2022)} Hydrogen\ production_{MWh}}$
Internal Rate of Return	WACC which should be used to get a NPV neutral project (no formula exists, but default Microsoft Excel IRR function is used)	

Table 6.K: Metrics used in the business mode

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