Offshore wind system integration 2030–2040

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in collaboration with

Contents

Executive summary

Background

Due to the ambition to reduce CO_2 emissions by 95% in 2050, the energy system, as we currently know it, is undergoing substantial change. An increasing share of the energy generated will come from weather-dependent renewable sources, such as solar and wind power. In the Netherlands, offshore wind in particular will play a vital role in achieving 2050 climate targets. A sustainable system also has the advantage of much lower energy losses than the current fossil fuel power plants. The disadvantage, however, is that production is weather dependent. A lot of wind capacity is therefore needed to achieve the required annual production. Expected installed capacity will increase from around 10-20 GW in 2030[1] to a maximum of 72 GW in 2050[2]. Integrating this offshore wind capacity into the energy system comes with major challenges:

- **Generation of solar and wind power is highly weather dependent**
  A fundamental characteristic of a renewable electricity system, in which electricity is largely generated by wind and sun, is that the installed capacity for power generation is significantly greater than the capacity of the final electricity consumption. This follows from the limited full-load hours of wind energy and solar PV.
- **Integrating all expected offshore wind energy in the electricity grid can result in grid congestion**
  The onshore electricity grid is not currently designed to cope with the transmission of the large quantities of electricity expected to be generated by offshore wind. This can result in grid congestion. The availability of land area to realise new connections also differs for each potential landing point.
- **Offshore wind combined with onshore renewables leads to periods of surplus**
  Even with the expected rise in demand through increased electrification, without energy conversion and storage, more than 30 GW of installed offshore wind capacity combined with onshore renewable energy would often result in periods of considerable surpluses. This has a negative impact on the business case for renewable energy plants, since the electricity price is low or even negative in some periods.
- **Hydrogen will play an important role in the future energy system; developments in the cost of green, blue, and imported hydrogen have an impact on the required infrastructure.**
  Current demand for hydrogen is around 175 PJ and is met entirely from fossil fuels. Domestic demand will rise sharply up to 2050: The Integral Infrastructure Outlook 2030-2050 (II3050) report applies a range of 267 to 708 PJ (excluding demand from aviation and shipping). In 2050, this hydrogen will be supplied through electrolysis (green hydrogen from electricity grid surpluses or through direct coupling with a wind and/or solar farm), by reforming (SMR or ATR) with CO_2 capture and storage, and through imports. Flexible energy conversion – such as hydrogen production through

[1] The accelerated realisation of 10 GW of additional offshore wind capacity before 2030 has not been taken into account when drafting the scenarios. This will have a limited impact due to the methodology used (determining the capacity in 2040 based on the II3050 scenarios). It is possible, however, that the acceleration prior to 2030 will be continued in the period up to 2040. The installed capacity in 2030 has no impact on the capacity to be distributed among the search areas, since the additional 10 GW will also be distributed among these areas.
[2] North Sea Energy Outlook, 2020

electrolysis of offshore wind electricity – can improve the value and business case of renewable energy generation.

- **A system with a large amount of renewable energy needs sustainable dispatchable capacity**
  In addition to periods of surplus, there will still be times when electricity from wind and solar is insufficient to meet demand. During these periods, sustainable dispatchable capacity (such as hydrogen power plants) is needed to guarantee security of supply. Flexibility of electricity demand can also help bridge these periods.

The roll-out of offshore wind from 2030 to 2040 must be implemented with due regard for the energy system as a whole. The long lead times for infrastructure projects means it is important to create clarity in the short term regarding the integration options we expect to be available. This study therefore addresses the following questions:

i. What will be the demand for and supply of electricity and hydrogen in 2040 in each of the four scenarios drafted in the context of the Integral Infrastructure Outlook 2030-2050 (II3050)?
ii. What are the developments surrounding offshore electrolysis and what is the expected feasible time frame for its large-scale application?
iii. What impact will integrating – according to different configurations – large quanitites of offshore wind capacity have on the electricity grid and hydrogen network, and on the energy system and its costs[3]?
iv. What role can onshore and offshore electrolysis play in the integration of offshore wind?

This study has been commissioned by the Netherlands Enterprise Agency (*Rijksdienst voor Ondernemend Nederland*, RVO) and was carried out by Guidehouse and Berenschot, in close collaboration with Gasunie and TenneT. The Ministry of Economic Affairs and Climate Policy, RVO, Gasunie, and TenneT were represented in a steering group to supervise this process.

Approach

A literature review, interviews, energy market models, workshops with market parties and qualitative and quantitative analyses were carried out for the purpose of this study. A summary of the approach is provided below for each research question.

The four II3050 scenario narratives were used to estimate electricity and hydrogen supply and demand in 2040. Two scenarios developed by TenneT and Gasunie from the 2022–2031 Investment Plan, namely the National Drive (IP-ND) and the International Ambition (IP-IA) scenarios, were used as a starting point for 2030. The II3050 scenarios were used for 2050, namely: Regional, National, European, and International steering (in Dutch: *sturing*). The IP-ND, with 16.6 GW of offshore wind in 2030, is in line with Regional and National steering in 2050. The IP-IA, with 12.6 GW of offshore wind in 2030, is in line

[3] A 'what-if' approach is used in this study: '*If a total of 31 or 38.5 GW of installed capacity is realised, what does that mean for the onshore grids and the energy system?*' The landing configurations and solutions were chosen by Guidehouse and Berenschot.

with European and International steering in 2050. It has also been assumed that in 2040, the National scenario has 38.5 GW of offshore wind, and the other three scenarios, 31 GW. The difference in assumed offshore wind capacity in 2040 stems from the II3050 narrative. For example, the National scenario assumes 72 GW in 2050, due to the high degree of self-sufficiency and focus on electrification being pursued. A (not always linear) interpolation was applied for 2040, whereby deviations from linear growth or contraction were determined on the basis of available sources (including the Cluster Energy Strategies), by making use of expertise within the Berenschot team and by reflecting on initial estimates by RVO, TNO, Planbureau voor de Leefomgeving (PBL), and members of the steering group. The results from the interpolation model were then exported to the Energy Transition Model (ETM) to create hourly supply-demand profiles.

Developments regarding onshore and offshore electrolysis have been mapped out by means of a literature review, interviews with market parties (including manufacturers of electrolysers and wind turbines), and a plenary market consultation session[4].

The search areas for offshore wind have been taken from the Draft North Sea Programme 2022-2027 and a realised capacity has been assumed for each search area based on obstacles, area size, and total offshore wind capacity. This study assumes five potential landing zones: Borssele, Maasvlakte, Beverwijk, Middenmeer, and Eemshaven. A landing point further inland in Graetheide (near Chemelot in Limburg) has been examined as an alternative. The options for landing offshore wind power are based on desirability from the perspective of the energy system – this study does not take into account other important factors such as public support, ecology, and spatial planning. These aspects are examined in the Exploration of Offshore Wind Energy Landing programme (*Verkenning Aanlanding Wind op Zee*, VAWOZ).

By way of illustration, the figure below shows an example of a configuration with all-electric landing (left) and a configuration with combined hydrogen landing from area 6 (right), both for the National scenario.

[4] This session was held under the Chatham House Rules. The identity and affiliation of the participants are therefore not disclosed.

A configuration includes the connections between search areas and landing zones, the capacity and type (electricity or hydrogen) of energy transmitted to shore, and any congestion measures in the form of electrolysis or additional electrolysis on the coast. These combinations form different potential solutions. This study explored the following solutions[5]:

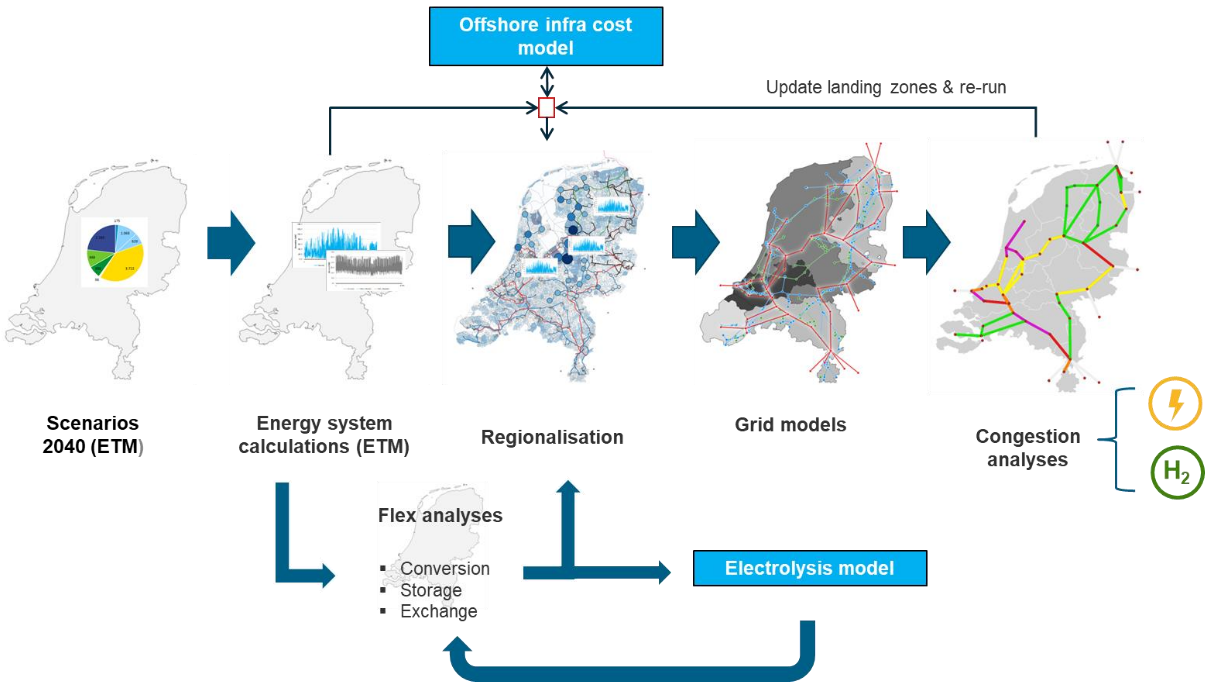
1. Fully electric transmission to shore in which electrolysis is only used when there is surplus power;
2. Fully electric transmission to shore with coupled[6] onshore electrolysis;
3. Fully electric transmission to shore with onshore electrolysis to prevent congestion; and

[5] We note that solution 1 is feasible under current applicable law and market rules. Solutions 2, 3, and 4 require changes to existing market rules.

[6] ‘Coupled electrolysis’ means that an onshore or offshore electrolyser is directly coupled with some or all of the capacity of a specific offshore wind farm, whereby the electrolyser load adapts to the profile of the wind energy generated by that specific wind farm. The coupled electrolysers have more full-load hours (approximately 5000 full-load hours) than electrolysers that only work when there is a surplus.

4. Combined electric transmission to shore and coupled offshore[6] electrolysis.

The quantitative analysis of the study was carried out in collaboration between Guidehouse, Gasunie, and TenneT. Parts of the II3050 model chain methodology were reused in order to analyse flexibility and regionalisation of supply and demand. Guidehouse developed and applied an optimisation model for electrolysis capacity and a cost model for offshore infrastructure. Gasunie carried out a congestion analysis of the future hydrogen network and TenneT carried out a congestion analysis of the electricity network. The figure below shows the model chain steps that were followed.



Results

i. Analysis of market developments in hydrogen and electricity supply and demand in 2040

This study looked at configurations to effectively feed the energy generated by offshore wind into the Dutch energy system. To determine suitable configurations, an estimate was first made of the supply and demand for hydrogen and electricity according to the four II3050 scenario narratives. The supply of electricity and hydrogen depends on the chosen solution. The table below provides an overview of the difference in supply of hydrogen and electricity between the scenarios for 2040. The supply figures relate to solution 3 (all-electric landing with onshore electrolysis to prevent congestion).

Table 1: Overview of electricity and hydrogen supply per scenario in 2040; supply volume is shown (in PJ) for a selection of indicators relevant to this study

Theme (figures in PJ)	PBL KEV 2020	Regional 2040	National 2040	European 2040	International 2040
Electricity supply	**427**	**1003**	**1011**	**903**	**881**
Offshore wind	*12*	*474*	*493*	*474*	*474*
Onshore solar and wind	*46*	*429*	*406*	*215*	*206*
(net) Import	*0*	*-21*	*-13*	*44*	*41*
Hydrogen supply	**176**	**529**	**512**	**668**	**905**
Green	*0*	*179*	*233*	*71*	*71*
H2 import for domestic demand	*0*	*-*	*-*	*86*	*430*
H2 import for aviation & shipping[7]	*0*	*262*	*189*	*258*	*284*
Total E and H2	**603**	**1271**	**1333**	**1312**	**1502**

The market analysis shows there will be a rise in total demand for electricity and hydrogen between 2020 (PBL KEV) and 2040 in all scenarios. This is due to the electrification of much of domestic transport, plus part of the built environment and industry; this occurs to varying degrees in each scenario. Demand for electricity is highest in the National scenario, due to the extensive electrification of industry and the high percentage of all-electric solutions in the built environment. In the European and International scenarios, industry also becomes more sustainable through the increased use of sustainable gases in the production process; demand for electricity is therefore lower in these scenarios than in the other 2040 scenarios. The supply of solar energy and onshore wind energy will increase up to 2040 in all scenarios. The Regional and National scenarios see onshore sustainable electricity generation increase almost tenfold compared to 2020.

There will be a sharp rise in supply and demand of hydrogen from 2020 to 2040. Whereas hydrogen is mainly used as a raw material in industry in 2020, by 2040 it will be used in lots of different points in the energy system by 2040. In all four scenarios, hydrogen plays a major role in industry, as both an energy carrier and a raw material. The Regional, National, and International scenarios make extensive use of back-up hydrogen power plants (dispatchable capacity). Hydrogen is also used in the European and International scenarios to make the built environment more sustainable: the expectation here is the

[7] II3050 was based on the principle of a 100% reduction in CO_2 by 2050; hydrogen demand (derivatives such as methanol and SAF have been converted to hydrogen demand) from aviation and shipping has also been calculated for this reason. Hydrogen demand from these sectors is considerable (40% or more) in each of the four II3050 scenarios for 2050. The European Commission has recently presented proposals for the EU Climate Law (Fit for 55), which show that neither international shipping nor the aviation sector will be obliged to fully reduce emissions by 2050. For this reason, the basic principle of II3050 for these two sectors has been abandoned and a reduction of 63% for aviation and 50% for shipping has been assumed. The 63% reduction is in line with the EU Green Deal proposal, while the 50% reduction is a rough estimate of the reduction target for the sector (IMO). Values for 2040 are an interpolation between 2030 and new figures for 2050.

cost of hydrogen will be sufficiently competitive compared to other natural gas alternatives. Hydrogen production is greatest in the Regional and National scenarios, due to a combination of offshore wind and a large amount of onshore solar and wind generation. By contrast, the International scenario relies mainly on hydrogen imports.

ii. Analysis of developments in offshore electrolysis

Whether offshore electrolysis can play a role in future integration of offshore wind energy and this could be possible was also investigated. The analysis produced the following insights:

- There are two main options: centralised electrolysis on an island or platform, and electrolysis integrated directly into wind turbines.
- Offshore electrolysis can have advantages over coupled onshore electrolysis. For offshore electrolysis, a pipeline can transport a considerably larger amount of energy than an HVDC cable. This can facilitate spatial integration and potentially save costs. The existence of a cost advantage depends on the impact on the system[8] and the scale (12 GW is assumed in this study).
- Offshore electrolysis also has disadvantages compared to onshore electrolysis. It limits the possibility of using the electricity generated directly (without conversion steps). However, not all hydrogen generated will be converted back into electricity. The energy system modelled in this study has many hours of surplus electricity and high demand for green hydrogen. In the 38.5 GW installed offshore wind capacity scenario, there is scope for electrolysis coupled with offshore wind, without significantly reducing direct consumption of renewable electricity.
- Compared to integrated electrolysis, centralised electrolysis offers the potential advantage of hybrid connections: combined landing of electricity and hydrogen. Interconnection with other countries can also be achieved using an energy hub or island.
- Integrated electrolysis has a number of advantages over centralised electrolysis:
    - The design of a wind farm and the wind turbines can be optimised for hydrogen production, removing a number of transformation steps from the electricity chain from wind turbine to electrolyser. The result is lower losses (a range of 8–10% has been mentioned) and cost savings on these components.
    - No island or large electrolysis platforms are needed, making the infrastructure cheaper.
- For both options, most market parties anticipate commercial-scale (GW) offshore electrolysis will be feasible by the early 2030s. For centralised electrolysis, the lead time for large-scale infrastructure is a bottleneck, while a significant challenge facing integrated electrolysis is the redesign and certification of wind turbines.

[8] Such as import and export of hydrogen and electricity and the use of dispatchable capacity.

iii. Effect of different landing configurations and electrolysis on the energy system and grids in 2040

Impact on the energy system

In all scenarios, the balance between demand for electricity (excluding electrolysis) and the generation of renewable energy is characterised by many hours of surpluses and shortages. This is a logical outcome of weather-dependent generation from these sources and the large installed capacity. Import and export and battery use help to balance supply and demand. Even after using these flexibility options, there will be periods of surpluses and shortages.

In this study, electrolysis is used to convert electricity into hydrogen during these periods of surpluses. The electrolysis capacity based on surpluses varies between 8 and 23 GW, depending on the scenario[9]. This capacity is determined on the basis of an optimisation module, where domestic production costs are weighed against import costs. The resulting number of full-load hours varies between 2500 and 3200 hours.

When there are shortages (after application of the other flexibility options), dispatchable capacity is necessary to guarantee security of supply. Hydrogen and methane power plants were used in the study. The installed capacity ratio for these types of power plants depends on the scenario. Total dispatchable capacity offered by these power stations varies between 27 and 29 GW[10,11] and the full-load hours vary between 800 and 1600 hours a year.

Impact on the electricity grid

In terms of the electricity grid, the usual response to anticipated structural bottlenecks is to invest in expanding the grid. This is also the statutory duty of TenneT, which it carries on the basis of its two-year investment plan. This study takes into account the grid expansions reasonably expected to take place. It then examines whether other options (relating to the landing of offshore wind and the use of electrolysis) can reduce potential bottlenecks and therefore the need to expand the grid. The numerical results in this summary generally relate to the National scenario, with 38.5 GW of offshore wind. Any further grid expansions by TenneT may affect the results.

The key findings **for solution 1** (landing of electricity, electrolysis only based on surpluses electricity) are:

- A fully electric transmission to shore, whereby offshore wind capacity is distributed across the major demand centres in the Netherlands, including a large amount (approximately 14 GW) to the Maasvlakte, leads to significant congestion, which would result in a need for additional infrastructure in this region.

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[9] For the solutions in which alternative electrolysis modes are applied, total electrolysis capacity increases while electrolysis capacity for surpluses decreases.
[10] The use of coupled electrolysis (whereby more renewable electricity is converted to hydrogen) has no significant impact on the required dispatchable capacity.
[11] This is more than the capacity of current gas-fired plants (excluding coal-fired power plants), namely 20 GW.

- Moving offshore wind capacity to Eemshaven (total landing approximately 10 GW) would significantly reduce electricity congestion in the Netherlands. The scenarios involving 31 GW of offshore wind show almost no structural congestion in the grid; limited structural congestion is anticipated in the 38.5 GW scenario. It should be noted that for a number of connections for which an expansion of infrastructure has already been proposed in the latest investment plan (IP2022), these expansions have not been taken into account[12].
- A significant installed onshore electrolysis capacity is provided for in both cases, ranging from 8 to 23 GW, depending on the scenario. The National scenario has a net electricity export of 10 TWh.

In summary, the envisaged high-voltage grid offers significant scope for integration of offshore wind energy, when wind farms are connected in a coordinated manner across different landing zones. Significant installed electrolysis capacity is provided at landing zones in all cases, although its operational aim is not to reduce grid congestion.

Insights into potential solutions 2, 3, and 4: the options examined for a modified electrolysis operating mode all result in a lower maximum access to offshore wind in the high-voltage grid, further reducing congestion. Introducing these forms of electrolysis also opens up alternative landing routes. In general, these solutions all alleviate or prevent incidental congestion at most connections. Connections with structural congestion will see a reduction in severity, however congestion will remain a structural problem[13].

Solution 2 (coupled electrolysis) - Fully electric landing whereby electrolysers are installed at relevant landing zones and linked to an offshore wind farm's generation profile. Electrolyser capacity is determined on the basis of an artificial feed-in limit for landing zones and the electricity from offshore wind feeding into the grid at the landing zone.

This solution enables a different distribution of the electricity integration over the landing zones. In the configuration examined, more capacity is landed in Middenmeer and Beverwijk (approximately 9 GW and 6 GW), where coupled electrolysis capacity is assumed (approximately 7 GW and 2 GW respectively). This design eliminates structural congestion at the connections near to landing zones. Congestion at a number of connections further inland reduces significantly (50–75%) compared to solution 1, but not enough to remove the need for investment. There is also a sharp fall in the net export of electricity (from 10 TWh to 0.2 TWh) and a rise in the use of dispatchable capacity (+7 TWh). With this solution, total installed electrolysis capacity varies 9 to 25 GW and the number of full-load hours between 3300 and 3800, depending on the scenario.

Solution 3 (grid congestion electrolysis) - All-electric landing whereby electrolysers are installed at relevant landing zones, which only activate when the electricity feed-in limits of the landing zones would otherwise be exceeded.

[12] The IP2022 had not yet been published when this study commenced. The IP2022 envisages reinforcements on a number of routes, which are not included in the grid model in this study (including Eindhoven–Maasbracht).
[13] No optimisation was carried out for this study to investigate whether the best technical system solution to congestion on the national electricity grid is additional electricity infrastructure or the use of flexibility options (such as electrolysis, batteries, curtailment, gas-to-power, interconnection) on each side of a bottleneck in the grid.

The same installed capacity is used as in the previous solution, which means the maximum input capacity per landing point remains the same. As a result, there are no significant differences in grid congestion results between solutions 2 and 3. Less electricity is converted into hydrogen, however, resulting in a lower number of full-load hours for the electrolysers (3500 to 4000 full-load hours), less use of dispatchable capacity (-4 TWh), and higher net export of electricity (+4 TWh). The electricity coverage ratio therefore increases (maximising the use of offshore wind in meeting baseload electricity demand) and energy loss is also reduced. With this solution, total installed electrolysis capacity varies from 9 to 25 GW, depending on the scenario.

Solution 4 (addition of offshore electrolysis) – Combined landing of electricity and hydrogen through the use of offshore electrolysis. The impact of converting electricity produced from 12 GW[14] of offshore wind into hydrogen on an energy island in the North Sea was investigated. After losses, around 11 GW less electricity would enter the grid during peaks. Compared to solution 2 (coupled electrolysis), congestion is reduced on some routes, although the difference is small. More electricity is converted into hydrogen, which leads to more use of dispatchable capacity (+1 TWh) and net import of electricity (1 TWh) over the year. The other potential solutions involve net exports of electricity. Total installed electrolysis capacity for this solution is 26 GW[15].

Offshore infrastructure costs

The differences in offshore infrastructure costs depend on the landing configurations and the use of offshore electrolysis. The redistribution of electricity landings from the west to the north of the Netherlands leads to a 2% cost reduction because less cable length is required. Cable length and associated costs are reduced by a further 2% under solutions 2 and 3 (coupled and anti-grid congestion electrolysis).

Use of offshore electrolysis (solution 4) reduces offshore infrastructure costs more significantly, down 13% compared to the case with onshore coupled electrolysis. A single hydrogen pipeline would connect 12 GW of offshore wind capacity, instead of six electrical connections. The largest contribution to cost savings, however, is the need for fewer HVDC converters. A hybrid connection with electricity (in this case 3 GW) and hydrogen can produce additional net benefits, the analysis shows.

Impact on the hydrogen network

For all scenarios and potential solutions, the landing of offshore wind energy and the associated electrolysis causes almost zero congestion in the hydrogen network[16]. Congestion in the hydrogen network does not occur with high generation from renewable energy sources, but at times when there is little or no wind and sun. At these times electricity is generated by gas-fired power plants, which are expected to run on hydrogen to a significant extent by 2040. Consequently, large volumes of hydrogen

[14] 12 GW is the assumed installed offshore wind capacity in search areas 6 and 7 in the National scenario.
[15] Please note: offshore electrolysis is only applied in the National scenario.
[16] The modelling is based on an extended hydrogen network compared to the envisaged network in 2030.

need to be transported from the storage locations to hydrogen power plants during these periods. Significant transport capacity and infrastructure is required in the form of pipelines and hydrogen compressors to achieve this. Only two locations for storage facilities have been assumed, namely Epe in Germany and Zuidwending in the Netherlands, resulting in significant demand for transport capacity from these facilities. The hydrogen network modelling in this study focused on the landing of offshore wind energy, so options for solving the potential hydrogen network congestion issue have not been explored further.

Conclusions

The main conclusions of this study are:

- **Coordination in combination with onshore electrolysis means it is possible to land and integrate electricity from 31 GW of offshore wind; landing 38.5 GW requires a limited number of additional electricity grid reinforcements**
  By taking a coordinated approach to landing electricity (taking into account the available space in the onshore electricity grid), 31 GW of offshore wind energy can be integrated into the envisaged high-voltage network without major problems. A number of bottlenecks are anticipated if electricity from 38.5 GW of offshore wind is to be integrated, for which a potential expansion of the high-voltage network up to 2040 appears possible and is partly already provided for in TenneT's 2022 Investment Plan. Nevertheless, large-scale conversion of surpluses to hydrogen is anticipated in every scenario because there is not always sufficient end demand for electricity, but there is demand for green hydrogen.
- **Alternative forms of electrolysis operation help to further reduce congestion**
  Alternative operating modes (coupled electrolysis, electrolysis when electricity feed-in limits are exceeded, or offshore electrolyse) can help reduce grid congestion. However, restricting freedom of operation is a challenge within the current legal framework (non-discriminatory access to the electricity grid in particular) and market model (there are no incentives to operate when this eases grid congestion).
- **Electrolysis plays an important role in meeting future demand for green hydrogen and in using surplus green electricity**
  The balance between electricity demand (end use) and supply is characterised by many hours of surplus green power (optimised electrolysis capacity in 2040, based on surpluses, ranges from 8 to 23 GW). This is due to an almost fully renewables-generated electricity mix, resulting in a large installed wind and solar PV capacity. Part of the surplus can be used to produce green hydrogen. The amount of surplus electricity that can be converted economically depends on the profile of the surplus electricity (lots of high peaks results in less green hydrogen production) and the price of imported hydrogen (a lower price results in less green hydrogen production).
- **Large-scale offshore electrolysis can play a role in integrating offshore wind into the energy system in the 2030s**
  Offshore electrolysis is expected to mature in time to play a role in integrating offshore wind into the energy system in the 2030s. Large-scale offshore electrolysis can offer cost benefits over coupled onshore electrolysis at the right scale. Centralised electrolysis on a large-scale energy island

and integrated electrolysis in wind turbines can both become relevant. Whether the use of coupled electrolysis (offshore or onshore) adds value to the system depends on the balance between supply and demand in the electricity and hydrogen system.

- **Transport capacity of the hydrogen network is driven by the use of hydrogen power plants**
  Transport of hydrogen from offshore wind landing zones does not determine the transport capacity required for the future hydrogen network[17]. The dominant driver for the capacity of the hydrogen network is transport from storage locations to hydrogen power plants for electricity generation during shortages in electricity supply from renewables.

Implications

The key implications of this study are as follows:

- **Coordinated electricity landing allows integration of a large amount of wind power, however this requires crossing the Wadden Sea**
  The right distribution of offshore wind capacity across the landing zones will allow the integration of electricity from 31 GW with limited grid congestion. Based on the grid model used, however, this requires significant landing in Eemshaven, which means crossing the Wadden Sea. As an alternative to concentrating electricity landings in the North, and with further expansion to 38.5 GW, further analysis should be carried out to determine the extent to which additional grid reinforcements would increase options. System costs and spatial planning aspects of alternatives would also need to be explicitly considered.
- **When applied at scale, offshore electrolysis offers cost advantages over coupled onshore electrolysis; site-specific research can provide insight into feasibility and costs**
  Offshore electrolysis can play a role integrating offshore wind energy up to 2040. To achieve economies of scale, further research into the possibilities of centralised and integrated electrolysis in search areas 6 and 7 is recommended. However, to ensure an effective contribution to the energy system, there must be the prospect of sufficient demand for green hydrogen and sufficient generation of renewable electricity. It must be taken into account that creating an energy island requires a long lead time; it is therefore advisable to take this decision in good time (around 10 years before the start of the operating phase of the first connected wind farms).
- **In a climate-neutral energy system, there should be more installed capacity than peak demand. Whether conversion to hydrogen is economically viable depends on the international H_2 price**
  In a climate-neutral energy system dominated by sources such as wind and solar PV, there will be many hours when surplus electricity is produced. This is inherent in the fact these sources are variable: more capacity should be installed than peak demand. Ensuring significant electrolysis capacity reduces the hours of surplus. The question, however, is what price electrolysis operators pay for electricity and whether this offers sufficient revenue for future offshore wind farms. The value of the hydrogen produced is leading in this: modelling a future international hydrogen market (and insight into the value of each ‘colour’) can provide insight. The international aspect is

[17] Whereby the maximum hydrogen feed-in at a single location remains limited to approximately 10 GW in this study.

important: in this study, hydrogen production costs are close to the assumed import prices, which can lead to an unprofitable component. The sensitivity analysis shows the hydrogen import price and electricity price for electrolysis influence optimal electrolysis capacity.

- **Timely decisions on 'desired' offshore wind capacity and landing zones are a precondition for upgrading the onshore grid; during the transition, development of supply and demand will not be synchronised**
  The choice of a specific offshore wind capacity in a specific year (for example 38.5 GW in 2040) and the landing zones has a major impact on required onshore infrastructure capacity. Timely and consistent policy will help ensure timely delivery of required onshore infrastructure. Significant changes in offshore wind capacity can mean grid reinforcements that have already been planned or carried out become over- or under- dimensioned. In many cases, the timely completion of expansion projects in the study phase for the high-voltage network is a precondition for the ability to connect large amounts of offshore wind to the electricity grid.
- **Location incentives and operating incentives for supply and demand can help reduce congestion**
  A large capacity of offshore wind, combined with a lot of onshore electrolyser capacity, changes the economic playing field within the energy market and energy flows. Larger peaks and troughs will load the grid differently. This study shows the right location and operating behaviour for electrolysis can reduce congestion. The right incentives, which can take various forms, need to be introduced to achieve this. Further research to identify effective incentives and how they relate to the current legal framework is recommended.
- **Four corners of the future energy system are explored; due to differences in the required infrastructure it is desirable for the government to take the lead and narrow the options**
  A timely decision needs to be taken on the role of hydrogen in the Netherlands' energy supply. A high degree of electrification requires a different approach to onshore infrastructure (for electricity, methane, and hydrogen) than a policy that focuses on large demand for hydrogen. The long lead times for infrastructure projects mean a decision is needed to guarantee future offshore wind projects are connected.
- **The deployment and location of hydrogen power plants determine the required transport capacity of the hydrogen network; research cost effectiveness of alternative delivery/storage**
  The location of large (closed cycle) power stations that run on hydrogen in this study is based on the locations of current gas-fired power plants[18]. The deployment of these power stations can create a peak demand for transport capacity in the hydrogen network. There are various options for dealing with this peak demand: locating the power stations nearer to the storage locations, greater conversion of gas pipelines to hydrogen pipelines, and alternative locations for the storage and import of hydrogen. These options should be explored in further detail.

Discussion

The key comments and notes from this study are:

[18] Smaller open cycle hydrogen power plants are distributed across the grid in proportion to peak deficits.

- The development of supply and demand was estimated for all energy carriers and sectors in 2040 as a starting point for the model chain. Scenarios for 2030 and 2050 were taken as key points, with supply and demand in these scenarios based on the average weather year of 2015. In a weather year with little wind, demand for hydrogen may be significantly higher due to a greater need to use hydrogen power plants. In a weather year with predominantly high winds and hours of sunshine, electrolyser operating hours are likely to be higher, although this depends on the international price and storage levels.
- Developments are sometimes more rapid than predicted. For example, who would have predicted that solar and wind costs would have fallen by around 50% and over 90% respectively in 20 years? Such uncertainty plays a major role in how accurate our 2040 estimates are, particularly when looking beyond a 10-year period.
- This study did not seek an optimal offshore wind capacity (which is a fixed value for each scenario). Neither did it analyse whether the future electricity market offers sufficient prospects for subsidy-free development of offshore wind. Such insight would require the application of market modelling and discussions with developers, investors, and the industrial clusters (the larger end-users).
- In practice, electrolysis operators will make decisions regarding hydrogen production based on electricity prices, the market price of hydrogen, and demand and/or availability of electricity/gas. This can lead to behaviour that differs from the modes modelled in this study. The expected development in the price of imported hydrogen plays an important role: if the import price is lower than average domestic hydrogen production costs, there may be an unprofitable component.
- In this study, optimisation focuses on different landing configurations, electrolysis capacity, and operating modes. Other measures have not been considered, such as grid reinforcements, expansion of interconnection capacity, other wind and solar PV capacity (outside of the variation in the scenarios) and different forms of demand-side response. Including other measures can lead to a system design with greater social benefits.
- Electrolysis needs the right investment signals and operational signals to effectively reduce grid congestion. There may be costs associated with restricting freedom of operation of the electrolysers (buying electricity at a higher price, lost income for wind farm operators because electricity cannot be sold on the market). At system level, another way of using electrolysers is similar to the current redispatch mechanism.
- The costs associated with an energy island are highly uncertain and based on the Danish cost-benefit analysis for the Danish energy island. In practice, costs depend on water depth and the wave climate at a specific location. A site-specific design can reduce this uncertainty.
- Additional interconnection, particularly from offshore wind hubs, can have a significant impact on the results. Greater exchange with other countries can reduce the need for electrolysis and the use of hydrogen power plants. Interconnection can also reduce grid congestion. On the other hand, reduced electrolysis can increase grid congestion. Further analysis is required to determine how such effects balance out.
- As offshore wind input mainly impacts the very high-voltage (EHS) grid (220–380 kV), this study only shows congestion on this grid. No research has been carried out into the potential impact on the high-voltage (HS) grid (110–150 kV).

- A steep cost reduction curve has been assumed for electrolysers. The current cost level for small-scale projects is above 1000 EUR/kW; for 2040 we assume 300 EUR/kW for onshore electrolysis. The impact of this assumption was taken into consideration in the sensitivity analysis.

1 Introduction

1.1 Project background

Offshore wind will play a vital role in the 2050 climate-neutral energy system, with an envisaged maximum installed capacity of 72 GW (DNV, 2020). In April 2021, the Netherlands Enterprise Agency (*Rijksdienst voor Ondernemend Nederland*, RVO) contracted Guidehouse and Berenschot to carry out a study on the integration of offshore wind into the Dutch energy system for the period 2030 to 2040. This study was carried out in close collaboration with Gasunie and TenneT, which performed some of the system analyses. There was also coordination with relevant policy programmes: the Main Energy System Programme (*Programma Energiehoofdstructuur*, PEH), Exploration of Offshore Wind Energy Landing (*Verkenning Aanlanding Wind op Zee*, VAWOZ), and the North Sea Programme. The results of the study will serve as input for these programmes and provide interested parties with insight into possible supply of and demand for electricity and hydrogen in 2040.

The grid companies (TenneT and Gasunie), policy programmes, and RVO were represented in a steering group that guided the project. RVO also supervised the project in terms of content and process.

1.2 Challenges presented by the roll-out of offshore wind energy up to 2040

Offshore wind is an important cornerstone of the energy transition in the Netherlands. In this study, we explore the impact of achieving 31 to 38.5 GW of offshore wind by 2040.

Integrating this offshore wind capacity into the energy system comes with major challenges and dilemmas:

- **Surpluses**. Current peak electricity demand is around 20 GW. Even with the expected rise in demand through electrification, without energy conversion, having almost double the amount of offshore wind capacity combined with sustainable onshore generation would result in periods of significant surpluses.
- **Trends in demand.** As previous studies have shown, it is also unclear whether electricity and hydrogen demand will develop in line with supply in the period ahead. If electricity demand develops at a slower pace, for example, there will be a larger increase in the number of hours in which surpluses occur than currently anticipated.
- **Grid congestion**. The onshore electricity grid is not currently designed for the transport of such large concentrated electricity production. If this issue is not addressed, it will be a limiting factor.
- **Landing zones.** The number of suitable electricity landing zones is limited, there is limited space both offshore and onshore, and we must remain within the limits of acceptable environmental impact.

1.3 Aims and approach of the project

The roll-out of offshore wind in the period 2030 to 2040 must be optimised. Long lead times for infrastructure projects means it is important to create clarity in the short term regarding the integration options we expect to be available. This provides the Government and market parties with insight into the available opportunities and unresolved challenges that still need to be addressed.

This study answers the following questions:

1. *How is demand for and supply of electricity and hydrogen expected to develop in the period 2030 to 2040? The following scenarios are explored for 2040:*
    a. *Regional steering*
    b. *National steering and a variant with greater electrification of industry*
    c. *European steering*
    d. *International steering and a variant with more GW of offshore wind energy for electrolysis*
2. *What are the developments surrounding offshore electrolysis? Is offshore electrolysis feasible in the period 2030–2040?*
3. *What is the impact of landing large amounts of offshore wind energy on:*
    a. *the electricity grid*
    b. *the future hydrogen network*
    c. *the energy system in a broad sense?*
4. *What role can onshore and offshore electrolysis play in the integration of offshore wind?*

The division of roles within the project team is illustrated in Figure 1.

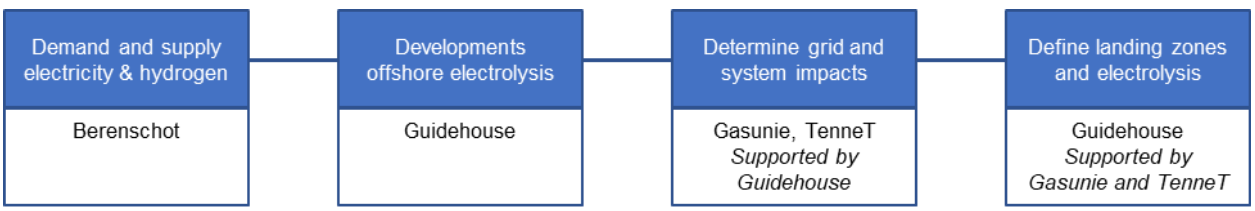

Figure 1: Schematic depiction of project responsibilities

1.4 Structure of the report

Chapter 2 describes how the trends in supply and demand have been determined for the various scenarios in 2040, the target year for this study. Anticipated demand in 2040 is shown for each scenario; for supply, further analyses have been carried out in relation to congestion/flexibility. Anticipated supply in 2040 is presented in chapter 6.2.

Chapter 3 outlines various potential configurations for the future energy system. A description is provided for offshore wind configurations and required offshore and onshore infrastructure for both hydrogen and electricity.

Chapter 4 looks at the developments in and potential of electrolysis as a technology. This information is then used as input for this project.

Chapter 5 explains how the analysis was carried out, addressing a number of aspects such as the analysis of grid congestion.

Chapter 6 describes the results: first the key results for the study as a whole, followed by the different scenarios.

Chapter 7 draws conclusions from and examines these results, followed by a discussion of the implications of the study and recommendations for the future in chapter 8.

2 Demand and supply scenarios for the target year 2040

This chapter answers the question: *What will be the demand for electricity and hydrogen in the period 2030–2040?* The chapter starts by looking at the chosen starting points/scenarios for 2030 and 2050, which serve as parameters within which demand and supply for the target year 2040 will develop (see Figure 2).

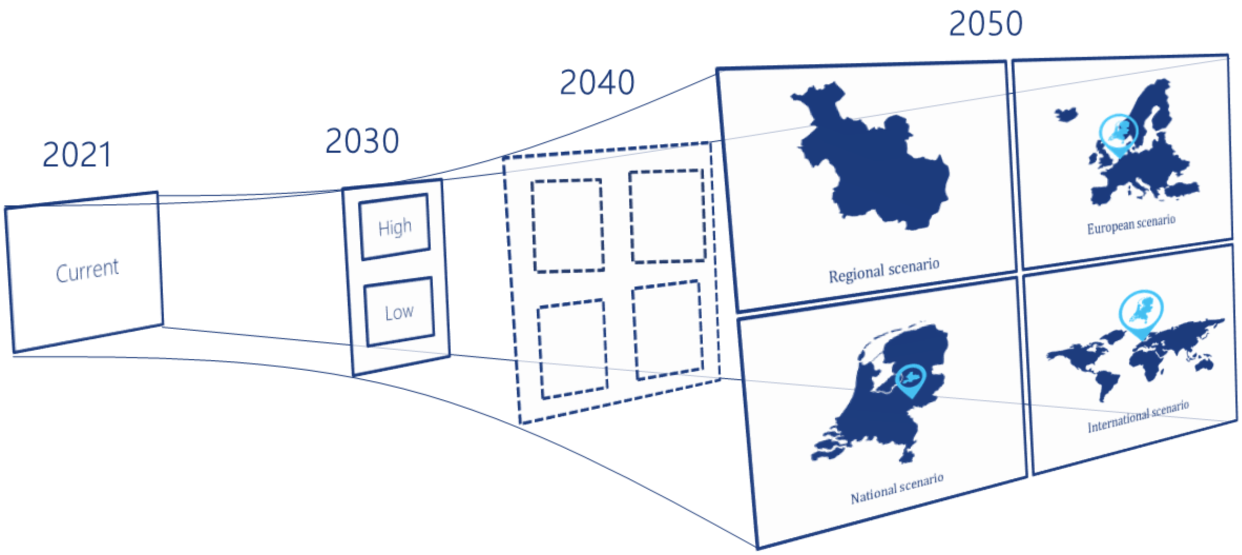

Figure 2: Schematic depiction of the scenarios used for the target year 2040. The two scenarios drawn up by the grid companies for the 2022 Investment Programme are used for 2030. High represents the ambition of 16.6 GW of offshore wind energy and is in line with the National scenario in 2050. Low is based on 12.6 GW of offshore wind and is in line with the other three scenarios.

It then discusses how demand and supply has been determined for each energy carrier and sector (‘development factors’) and the nature of and reasons for any deviations from the existing scenarios and/or chosen starting points for 2040.

Finally, electricity and hydrogen demand in 2040 is presented for each scenario. Electricity and hydrogen supply is determined in a similar way. In this study, however, supply is also partly determined by analysing congestion, flexibility, and grid capacity (see chapters 3 to 5). For this reason, the result of the supply interpolation has not been included in this chapter.

2.1 Starting point scenarios for 2030 and final pictures for 2050

Firstly, the two 2030 scenarios (drawn up by TenneT and Gasunie) on which the 2022 Investment Programme (IP2022, or IP22) is based were used to chart the development of electricity and hydrogen supply and demand in 2040. These two 2030 scenarios are linked to the four 2050 Climate-neutral Energy Scenarios drawn up by Berenschot and Kalavasta as part of the Integral Infrastructure Outlook 2030 – 2050 (II3050) (Berenschot, 2020).

Below is a brief summary of the scenarios for 2030 and 2050 and how the 2030 scenarios are linked to the 2050 scenarios.

Summary of Integral Infrastructure Outlook scenarios (2050):

Year	Scenario	Description
2030	International Ambition	The IP22-IA assumes 12.6 GW of offshore wind power. This scenario is line with the 2050 European and International steering scenarios in terms of narrative.
	National Drive	The IP22-ND assumes 16.6 GW of offshore wind power. This scenario is line with the 2050 Regional and National steering scenarios in terms of narrative.
2050	Regional	In the Regional scenario, local and regional government bodies steer the energy transition. The Netherlands is becoming fully sustainable and is aiming for a high degree of self-sufficiency. As well as generating a large amount of sustainable energy, the Netherlands has a great need for storage and other flexibility options. Energy-intensive industry is in decline, as is demand for international transport. There is a strong focus on circularity. Installed offshore wind capacity is 43 GW.
	National	In the National scenario, national government takes the lead. Initiatives are mainly set up at a national level and are large-scale in nature. Strong government steering gives clear direction to the transition, ensuring climate targets are met. Self-sufficiency is also the aim in this scenario, to limit dependence on other countries. Energy is primarily generated through large-scale projects, such as large-scale offshore wind farms, onshore wind farms, and solar farms. Energy-intensive industry remains at the same level in terms of production. Installed offshore wind capacity is 72 GW[19].
	European	The European scenario assumes strong steering by Europe. A general CO_2 tax is introduced at European level. This tax applies to all sectors. The speed of the energy transition is directly correlated to the increase in this tax, making it possible to achieve the 2050 climate targets. There is no focus on specific technology, meaning that only the most cost-effective technologies are implemented. One of the results of this approach is that there is scope for blue hydrogen and other CCS applications. In some cases, import of sustainable energy carriers is chosen as the most cost-effective solution. The industry is growing in scale in this scenario. Installed offshore wind capacity is 42 GW.
	International	The International scenario assumes a fully open international market. There are no restrictive or protectionist measures on this market and energy can therefore be traded freely. In this scenario, the Netherlands is heavily dependent on imports. This scenario involves strong international cooperation resulting in an advanced energy infrastructure, thus enabling energy to be imported in high volumes. Industry is increasing in scale. Installed offshore wind capacity is 38 GW.

[19] In the II3050 scenarios, part of the offshore wind capacity – 20GW in the National scenario – is designated to improve the sustainability of part of the demand from the international transport sector. This study examined the optimisation of energy landing. The way in which the available green hydrogen is used has not been specified in detail, since this depends largely on technological developments and the cost of alternatives available to bunkers and the aviation sector in the period up to 2040.

2.2 Development in demand and supply in the period 2030–2040–2050

An interpolation was carried out between 2030 and 2050 to provide a picture of the demand for energy and the supply for each energy carrier and sector in 2040. To do this, the IP2022-ND (National Drive) and IP2022-IA (International Ambition) scenarios of all grid companies and the four Climate-Neutral Energy Scenarios (Regional, National, European, and International) were first combined (see table above). It was then examined to what extent development in the period 2030–2040–2050 is linear for each energy carrier and sector. Any non-linearity in the development for each energy carrier/sector was expressed as a "development factor". These development factors were determined by looking at available sources (including the Cluster Energy Strategies (PBL, 2021)), by making use of expertise within the Berenschot team and by reflecting on the estimates made by RVO, TNO, PBL, and Steering Group members. The development factors indicate whether we expect an acceleration or deceleration compared to a linear growth trajectory[20].

Figure 3 shows the impact of the development factors, if demand for an energy carrier rises between 2030 and 2050. In the event of a linear increase between 2030 and 2050, 50% of total growth will be achieved by 2040, which is indicated by a development factor (DF) of 1. If growth between 2030 and 2040 is expected to be faster than the average between 2030 and 2050, the development factor is estimated to be higher. The figure on the left illustrates this type of accelerated development, in which a development factor of 1.5 means that 75% of total growth between 2030 and 2050 will be achieved by 2040. The figure on the right shows the opposite effect: here, growth is expected to be less than linear between 2030 and 2040. This is represented by a development factor of 0.5, which means 25% of total growth between 2030 and 2050 will be achieved between 2030 and 2040. It therefore also means growth is expected to increase rapidly between 2040 and 2050, since 75% of total growth will, in that case, be achieved between 2040 and 2050.

[20] When determining the development factors, a distinction is made according to the trends in demand from sectors for hydrogen, electricity, and natural gas, and the trends in supply for these three energy carriers. Finally, hydrogen demand and supply within international transport was addressed (this is beyond the scope of the national targets, but is a sector that could potentially start to demand high volumes of hydrogen). In principle, three development factors are determined for the trends in demand from a sector, namely the development factor in respect of demand for electricity, hydrogen, and natural gas, which are related.

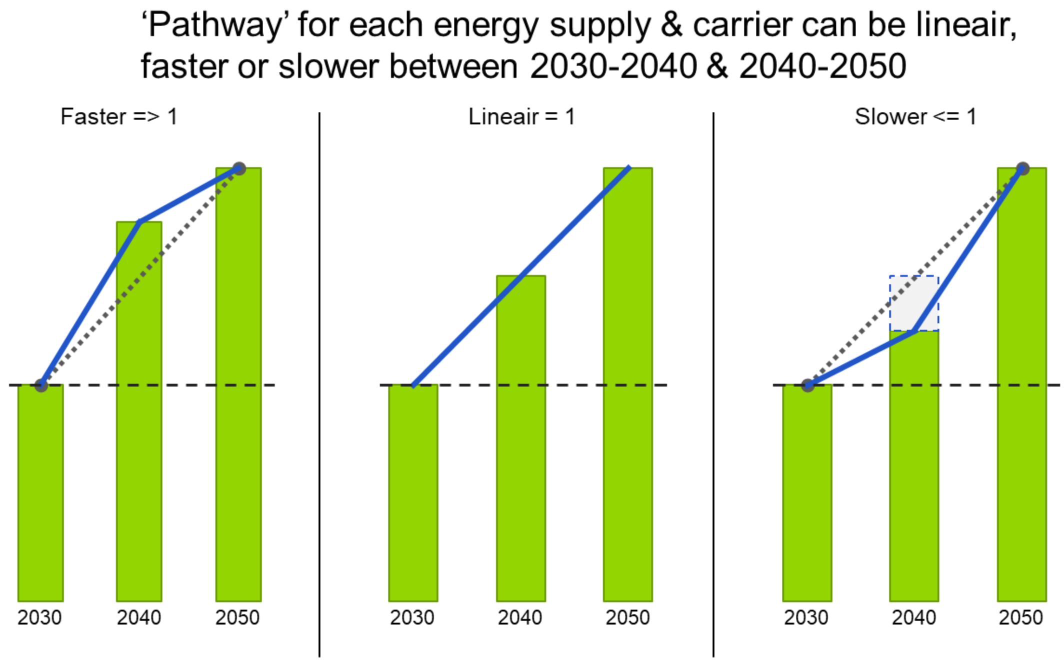

Figure 3: Depiction of the way in which development factors impact growth between 2030–2050

For example, a high development factor applies to electricity demand from transport. This is based on current rapid growth in the number of electric vehicles in the Netherlands, which is expected to continue at a fast pace. Due to the relatively short replacement period that applies to vehicles (+/- 10–15 years), the vast majority of car owners are expected to switch from a fuel-powered vehicle to an electric vehicle between 2030 and 2040. The effect is further reinforced by the stricter regulations the European Commission is expected to introduce prohibiting the sale of new fuel-powered vehicles from 2035 (PBL, 2021). Based on these two trends, the estimated development factor is 1.75, whereby no distinction is made between the four scenarios for 2040[21].

This means there is no difference in relative growth between the scenarios, however the scenarios do differ in terms of absolute growth in electricity demand between 2030 and 2050. For example, in the 'National' scenario, electricity demand from the transport sector grows by 53 PJ between 2030 and 2050, whereas demand in the 'European' scenario grows by 99 PJ in the same period. Both have a development factor of 1.75, which means 87.5% of expected growth will have already been achieved by 2040. This results in a growth in electricity demand (for transport) between 2030 and 2040 in the 'National' scenario of 49 PJ and in the 'European' scenario of 86.6 PJ. The development factor is the same for both scenarios, however the larger role of electric vehicles in the 'European' scenario means absolute growth is greater than in the 'National' scenario.

The estimated development factor for electrically-powered transportation is the same for all Climate-neutral Energy Scenarios, however the development factors can also differ between the scenarios. One example is the industrial sector, where there is a marked difference in the development factor for

[21] We use the same narrative for 2040 as for the four scenarios devised for 2050.

hydrogen demand between scenarios such as ‘Regional’ and ‘International’. A detailed description of the reasons behind these development factors and the development factors for other sectors can be found in appendix B.

2.3 Assumptions in the 2040 scenarios

Following on from the four scenarios developed for the year 2050 (as part of II3050), this study assumes the same scenarios, but for the target year 2040. Two variants have also been developed in consultation with TenneT and Gasunie: the National+ variant – electrification of industry and the International+ variant – additional offshore wind energy.

In addition to the estimated growth trajectory between 2030 and 2050 for each energy carrier and sector (see 2.2), a number of other assumptions have been applied that influence expected development of supply and demand, namely:

- **Assumed installed offshore wind capacity in 2040**[22]
  - The National scenario assumes 38.5 GW of offshore wind, in line with the higher capacity of 72 GW anticipated in this scenario for 2050.
  - The Regional, European, and International scenarios assume 31 GW of offshore wind. These three scenarios have 43 GW, 42 GW, and 38 GW of offshore wind in 2050 respectively, meaning a lower amount of offshore wind in 2040 is more realistic. The 31 GW is based on analysis by the North Sea Wind Power Hub consortium[23].

- **Developments in CCS**

  In recent times, many subsidies (SDE++) have been awarded to parties that want to make existing SMR plants (for the production of grey hydrogen) more sustainable by capturing some of their CO_2 emissions and storing it in empty gas fields. Our estimate is that around half of current grey hydrogen production should be viewed as low-carbon production by 2025. As a result, the share of grey hydrogen in the supply mix is decreasing while the share of blue hydrogen is on the rise: this trend will continue for at least 15 years, which is the term of the SDE subsidy. Once the SDE subsidy has ended, we anticipate a complete phase-out of grey hydrogen due to the higher costs associated with CO_2 emissions. The Renewable Energy Directive II (REDII), part of the ‘Fit for 55’ package, imposes a target of 50% use of renewable fuels of non-biological origin (RFNBOs) in industry by 2030[24].

- **Developments in international transport (aviation and shipping)**

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[22] None of the scenarios currently take into account the recent announcement that 10 GW of additional offshore wind capacity is to be realised. Furthermore, capacity in 2050 is a combination of production to meet domestic demand and part of the demand for green hydrogen from bunkers and aviation. As stated, these elements have been merged.
[23] This involves an interpolation between installed capacity in 2030 according to IP22 and installed capacity in 2050 according to the national scenario in the II3050 scenario study.
[24] The precise details of how this package will affect blue hydrogen production are not yet known.

The underlying principle of the Integral Infrastructure Outlook 2050 (II3050) is a 100% reduction in CO_2 by 2050; for this reason, demand for hydrogen[25] from aviation and shipping has also been calculated. Hydrogen demand from these sectors is considerable (40% or more) in each of the four 2050 scenarios. The European Commission recently presented the proposals for the EU Climate Law (‘Fit for 55’), which shows that neither international shipping nor the aviation sector are or will be obliged to fully reduce their emissions by 2050. For this reason, the basic principle of II3050 for these two sectors has been abandoned and a reduction of 63% for aviation and 50% for shipping has been assumed. The 63% reduction is in line with the EU Green Deal proposal, while the 50% reduction is a rough estimate of the sector's reduction target.

- **Two variants on existing II3050 scenarios**
  - Variant: International – offshore wind energy +: For 2040, this variant assumes an installed offshore wind capacity of 38.5 GW (7.5 GW more than in the basic scenario). The additional installed capacity will be used to produce green hydrogen, replacing some of the need for hydrogen imports.
  - Variant: National – electrification of industry: The industrial electrification variant of the National scenario shows the impact of electrifying a larger proportion of industry (particularly the chemical industry and refining). An additional electricity demand of 115 PJ has been assumed within industry for 2050. This demand for additional electricity replaces part of the demand for hydrogen as an energy source in industry assumed in the standard National scenario.

2.4 Demand for electricity and hydrogen in 2040

The national grid companies’ investment plans outline energy scenarios for 2030. A striking feature of these scenarios is that there is still very little difference in hydrogen demand in 2030. By 2040, there is a big difference in hydrogen demand particularly, whereas electricity demand is still very similar in all of the scenarios. However, the electricity is used in other areas of the energy system. This section looks at the need for electricity and hydrogen in the four scenarios and the two variants.

Hydrogen demand

Annual hydrogen demand for 2040 is shown in Figure 4. Demand for hydrogen is noticeable lower in the Regional scenario. Industry has a lower demand for hydrogen due to the assumed contraction in this sector. In this scenario, the highest demand for hydrogen is from electricity production. In addition, hydrogen is mainly used in industry as a raw material and for energy purposes. There is also low demand for hydrogen from heavy transport.

In the National scenario, hydrogen is used for the same purposes as in the Regional scenario. However, annual hydrogen demand is higher than in the regional scenario. Increased demand for hydrogen is particularly evident in industry and the electricity sector. This is mainly due to the fact that, in this

[25] Derivatives such as methanol and Sustainable Aviation Fuel (SAF) have been converted to hydrogen demand

scenario, the size of industry stabilises and remains at current levels. Industry is therefore larger than in the regional scenario. The larger industry and associated demand for electricity also explains the greater demand for hydrogen from back-up power stations in the electricity sector. In the transport sector, more use is made of hydrogen as a fuel.

Annual hydrogen demand is higher in almost every sector in the European scenario than in the National Scenario. This is due to the assumption of a more level playing field at international level, which allows industrial growth. In this scenario, a significant proportion of hydrogen is produced from natural gas using CCS, and can therefore be used in more places in the energy system. There is growth in industry compared to today. In this scenario, back-up power stations in the electricity sector run more on green gas and/or (still) partly on natural gas (possibly with CCS), which means hydrogen demand in this sector is lower than in the other scenarios. In the European scenario, homes are partly heated with hydrogen by means of hybrid heat pumps, resulting in a demand for hydrogen from the built environment.

The highest annual hydrogen demand occurs in the International scenario. In terms of industry, the developments we see in the International scenario are largely the same as those in the European scenario. We anticipate a difference in demand from the electricity sector and the built environment. In the International scenario, back-up power stations run entirely on hydrogen and we assume that all hybrid heat pumps in the Netherlands run on hydrogen, meaning hydrogen demand from the built environment is greater than in the European scenario.

The difference in hydrogen demand between the International and the International+ (additional offshore wind) scenarios lies in the electricity sector. In the International+ scenario, more electricity from wind is generated, resulting in an increase in the number of hours electricity can be used directly as electricity and a decrease in the number of hours dispatchable power plants need to operate. Demand for hydrogen in the National + electrification of industry scenario is considerably lower than in the National scenario. This is mainly due to the high level of electrification in industry, resulting in the lower use of hydrogen. However, electrification does lead to a higher demand for hydrogen in the electricity sector.

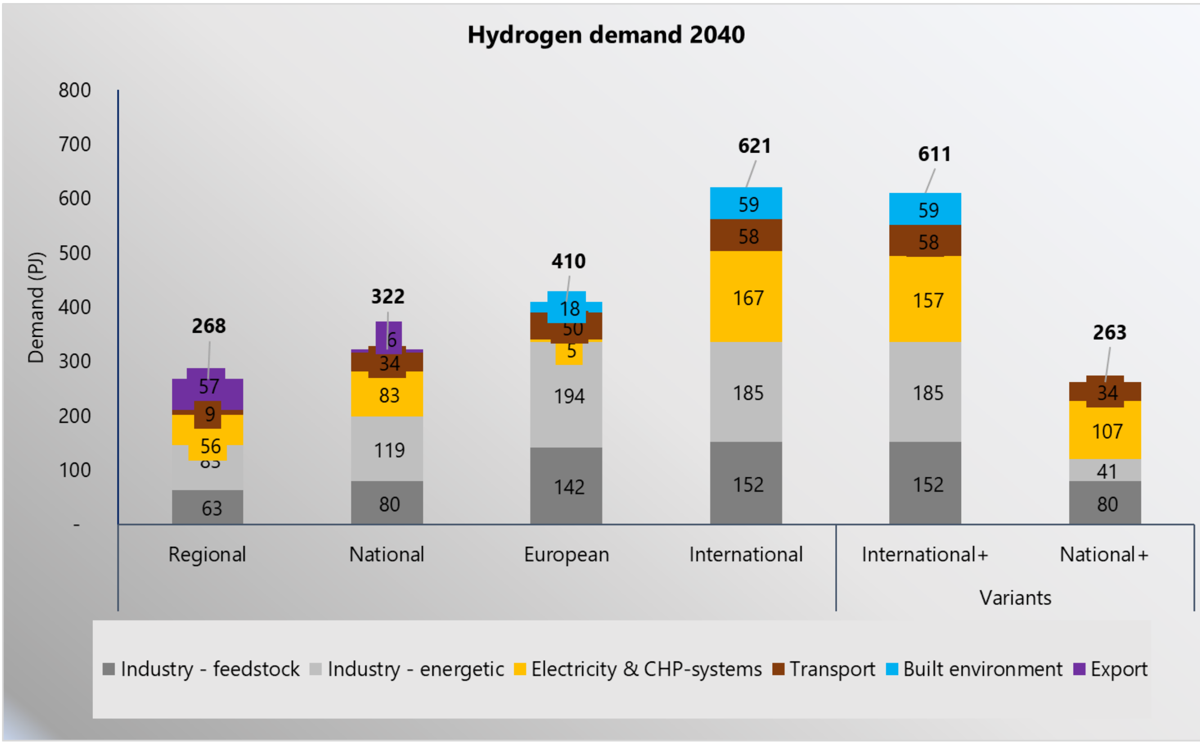


Figure 4: Hydrogen demand in the 2040 scenarios (based on the solution involving electrolysis to prevent congestion)

Electricity demand

Electricity demand in 2040 is shown in Figure 5. The differences between the scenarios are noticeably smaller here than for hydrogen demand. Demand for electricity is higher in the Regional and National scenarios than in the other scenarios. These scenarios aim for self-sufficiency, resulting in high demand from the energy sector (so limited import of electricity), where electricity is converted into hydrogen by means of electrolysis (so limited import of hydrogen). Demand for electricity from industry is higher in the National scenario than in the Regional scenario, because industry is larger. The other sectors are around the same in these two scenarios.

There is a lower demand for electricity from the energy sector in the European and International scenarios. The European scenario focuses on green gas, blue hydrogen, and CCS, while the International scenario focuses on the availability of cheap imports. This is mainly because the ambition/world view for self-sustainability has been abandoned here. Hydrogen does not need to be produced exclusively in the Netherlands. Electrolysis capacity is used mainly for surpluses. Demand for electricity from industry is higher in both scenarios than in the Regional and National scenarios, due to assumed growth of industry. Demand for electricity from agriculture and transport is lower in the International and European scenarios than in the Regional and National scenarios, due to the greater use of hydrogen or biofuels in the mobility/transport sector.

The International – offshore wind + scenario is a derivative of the International scenario. The biggest difference is greater sustainable electricity production than in the International scenario, resulting in more storage in batteries and conversion via electrolysis and thus greater losses and more power-to-gas (P2G). This therefore means higher green hydrogen production, at the expense of hydrogen imports. The demand sectors are also identical in both scenarios. The National+ – electrification of industry scenario assumes a high degree of electrification of industry compared to the National scenario, as reflected in the electricity demand from industry, but which also has an impact on losses, exports, and P2G demand. Demand for electricity is therefore higher than in the National scenario.

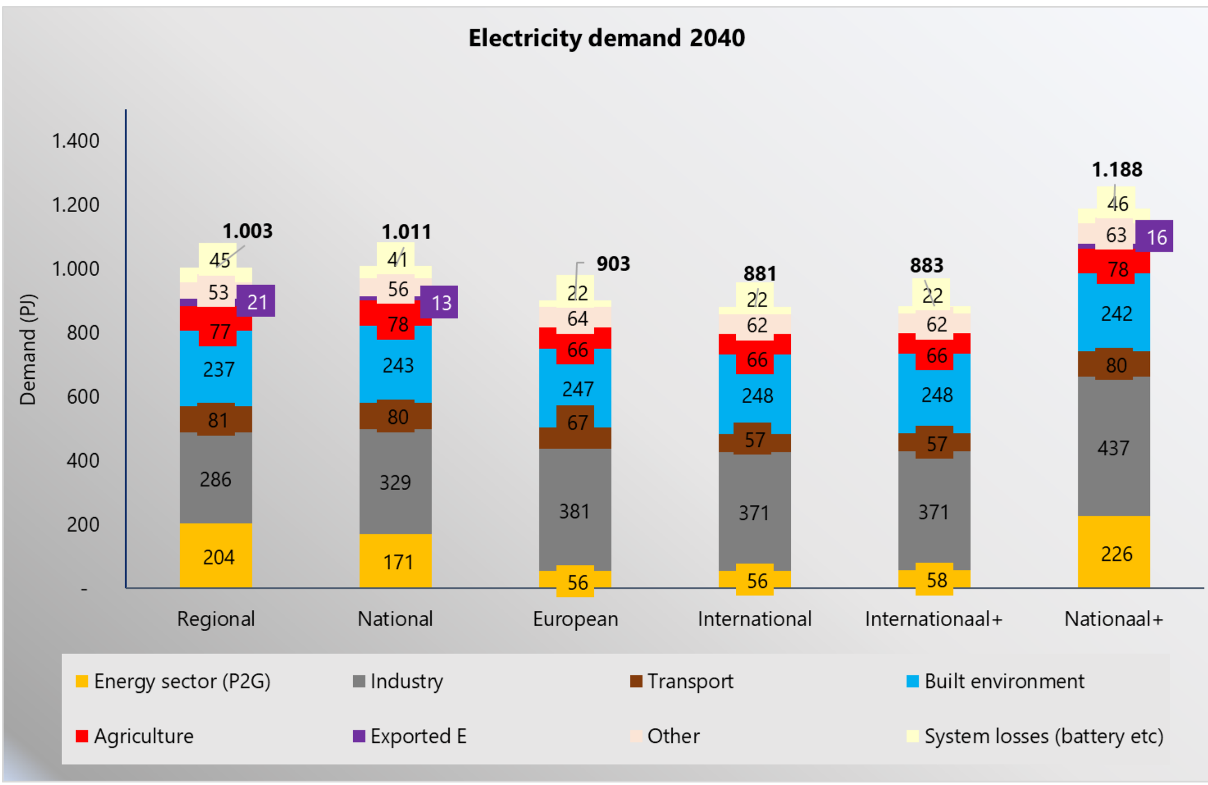


Figure 5: Electricity demand in the 2040 scenarios (based on the solution involving electrolysis to prevent congestion)

3 Offshore wind and infrastructure configurations

In this study we define a number of configurations for landing offshore wind, integration of hydrogen production from sustainable energy, and the implications for both electrical and gas infrastructure. The configuration choices determine the different energy flows and required infrastructure, leading to different cost totals.

3.1 Offshore wind configurations

The possible offshore wind configurations in this study are determined on the basis of a number of aspects. The starting point is total offshore wind capacity for the target year 2040, starting from the Roadmap 2030 and the Draft North Sea Programme 2022-2027. In this programme, various search areas are considered for offshore wind in the North Sea.

IJmuiden Ver Noord (2 GW) and the southern part of Hollandse Kust West (700 MW) are expected to be the first areas developed beyond the current Roadmap 2030. In order to align with the scenarios in IP2022 (12.6 and 16.6 GW, depending on the scenario considered), we assume that only 2 GW will be developed at IJmuiden Ver Noord and we disregard the southern part of Hollandse Kust West. This gives a total maximum capacity of approx. 26 GW (38.5 - 12.6 GW[26]) to be distributed across the new search areas. We assume all offshore wind capacity realised by 2030 will remain operational until 2040.

Roadmap 2030	IJmuiden Ver Noord	Capacity in 2040	Total capacity to divide over new search areas
10.6 GW	+2 GW (12.6 GW)	31 - 38.5 GW	18.5 - 26 GW

Please note, the accelerated realisation of 10 GW of additional offshore wind capacity before 2030 has not been taken into account when drafting the scenarios. This will have a limited impact due to the methodology used (determining the capacity in 2040 based on the II3050 scenarios). It is possible, however, that the accelerated pace of development to 2030 will be continued up to 2040. The installed capacity in 2030 has no impact on the capacity to be distributed among the search areas, since the additional 10 GW will be distributed within these areas.

[26] Due to the existing offshore wind energy capacity and the choice of 2 GW HVDC connections, 38.6 GW is assumed in the analysis for the high offshore wind capacity scenario.

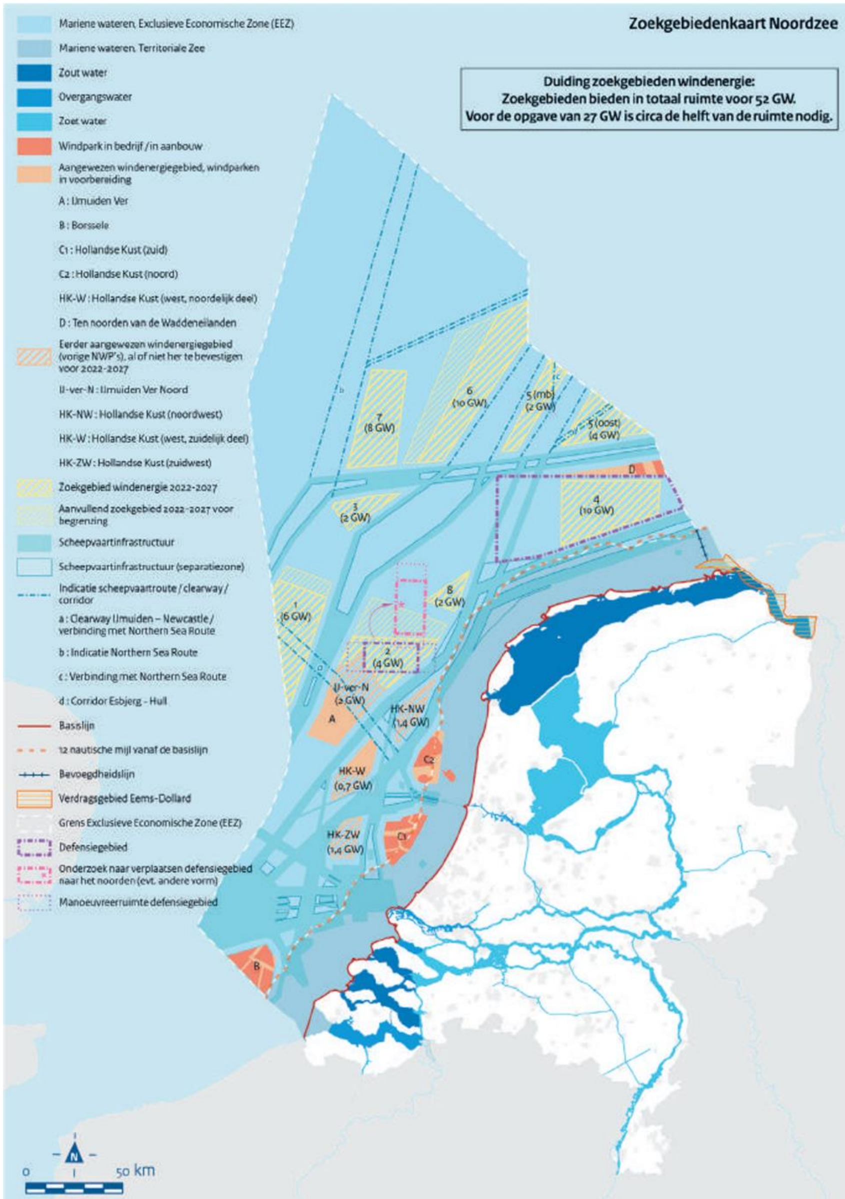


Figure 6: Draft North Sea Programme Map, new offshore wind search areas

The first subdivision of wind capacity per search area has been performed on the assumption that all wind energy will be transported to the coast as electricity. We will revise the subdivision at a later stage base on the possibility of offshore electrolysis. We follow an order based on the above considerations, in which areas with little impact on shipping and fishing and that are at a limited distance to the coast are realised first.

When subdividing the capacity, we first looked at potential capacity in areas 1, 2, 3 and 5 (search areas 4 and 8 are considered difficult to achieve). Based on the assumed capacity below, there then remains (for 38 GW in 2040) 12 GW to be realised in areas 6 and 7. The decision was taken to develop the majority of area 6 for 2040 and to place area 7 last on the list. In the scenarios with 31 GW offshore wind capacity, no capacity is assumed in area 7 and area 6 is last on the list. Table 1 provides an overview of assumed capacity per search area and the underlying rationale. The issue of landing is not taken into account.

Table 1: overview of assumed capacity per search area for the 38.5 GW offshore wind scenario

Zoek-gebied	**Assumed capacity**	**Reasoning**
1	6 GW	6 GW is equal to the maximum potential of the seach area. It is one of the first areas to be developed beyond the 2030 Roadmap. Relatively few obstacles and few major adjustments necessary to realise the full potential.
2	2 GW	Less than the maximum capacity of 4 GW. It is part military zone and the area knows multiple O&G platforms with helicopter desks. Realising the full potential of 4 GW is not considered realistic.
3	2 GW	Extension of the search area may allow 4 GW. Limited to 2 GW if extension is not possible.
4	0 GW	No development assumed as it lies in a military zone. .
5	4 GW	Search area 5 consists of two areas, west and east, with respectively 2 and 4 GW of potential. Development in the western area is considered challenging due to nearby shipping routes and collision risks. It is assumed that the eastern area (4 GW) will be see development before 2040.
6	8 GW *31 GW variant: 4.5 GW*	The maximum potential of this search area is 10 – 12 GW. The latter would require moving the western boundary. 8 GW is assumed for 2040 as to not develop the full area. Wake losses within this ara can be reduced by exploiting area 7 as well.

7	4 GW *31 GW variant: 0 GW*	Maximum potential of 8 GW. 4 GW is what remains to be developed after consideration of het previous areas.
8	0 GW	The area is too small to host 2 GW. In addition, it is contested by the shipping industry.

The landing of capacity in these search areas is dependent on factors including the onshore electricity grid, the various demand centres, and the planned hydrogen network. This makes it impossible, for example, to land all capacity at the nearest landing point, as this would lead to major grid congestion and require significant additional investment in onshore infrastructure.

In line with the above, landing therefore needs to be spread across demand centres (for example, industry clusters at Maasvlakte and Eemshaven). An estimate is also given regarding the possibility of accessing current and future national networks in the form of electricity alone or combined with hydrogen, taking into account existing infrastructure, TSO investment plans, and electricity and hydrogen demand in each region. Offshore wind energy landing locations have been chosen that are representative of the region. Inter-regional differences have no impact on the modelling results, with the possible exception of a small number of routes within the region in the grid analyses. This study examines the following landing zones[27]:

- Eemshaven
- Den Helder, Middenmeer substation
- North Sea Canal, Beverwijk substation
- Maasvlakte
- Borssele

An initial distribution of the search areas across the landing zones has been defined on the basis of quantitative and qualitative arguments, with the aim of starting the modelling.

The offshore wind capacity installed by 2030 has also been distributed across these five locations. In some cases, this is a deviation from reality (for example the Prinses Amalia wind farm), but given the limited capacity this does not have a significant impact on the results.

[27] In the course of the analysis, we also explore the usefulness of a sixth landing point in Maasbracht, Graetheide substation. This is described in further detail in Chapter 6.1.1

Table 2: Overview of offshore wind energy landing to be realised by 2030

Landing zone	Pre-2030 capacity
Borssele	3.4 GW
Maasvlakte	5.4 GW
Noordzeekanaal/Beverwijk	2.5 GW
Den Helder, Middenmeer substation	0 GW
Eemshaven	1.4 GW

Figure 7: Example of offshore wind energy connection to landing zones

For the initial configuration, it was decided to land the majority of the electricity at demand centres in Zeeland and Maasvlakte. This study does not identify specific routes, but calculates distances according to the most direct path plus a factor of 1.3 to estimate route length.

Each configuration is analysed (described in chapter 5) to determine its impact on the energy system, onshore grids, and infrastructure costs. Based on these results, new choices are made in relation to landing configurations (location, capacity, and form) and use of electrolysis.

Break-out 1: offshore electricity production

Offshore electricity production from offshore wind forms a large part of the total electricity supply in the scenarios considered. Different wind profiles have been used, all based on the climate year of 2015, for the purpose of energy system modelling. We have used the ERA5 climate dataset provided by ECMWF. Individual windspeed-timeseries are determined for each of the offshore wind search areas.

WindPRO software is used to model a wind farm power curve. A modern wind farm is assumed in terms of installed capacity, rotor diameter, and wind turbine rated capacity. Wake losses are included in the modelling. In addition, electrical losses (transformer, converter, inter-array, and export cable) and technical availability of the wind farm are considered.

3.2 Offshore infrastructure

In this study we use different types of infrastructure to transport offshore wind energy to shore in the form of both electricity and hydrogen. We also look at offshore hydrogen production, which can offer advantages in terms of infrastructure costs, limiting curtailment of offshore wind, and limiting onshore congestion problems. The disadvantage here is the wind energy produced is fed directly to the electrolyser and therefore cannot be used to meet onshore electricity demand. In this section, we describe the four infrastructure configurations analysed in this study.

All-electric transmission

All offshore wind energy is transported to land as electricity. In this configuration, we assume 2 GW offshore HVDC converter stations connected to the coast with a bipolar HVDC export cable for wind farms after 2030. The wind farms are connected to the HVDC stations with 66 kV inter-array cables. These are radial connections, without interconnection to other countries or between different offshore stations.

The export cable is connected to the landing point via a 2 GW onshore HVDC converter station.

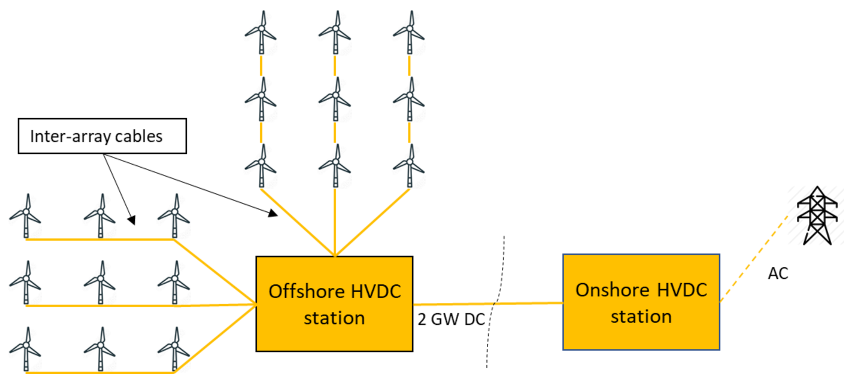


Figure 8: schematic overview of electricity landing

Hydrogen transmission via a central energy island

In this study, we explore the possibility of an artificial raised sand island where offshore electrolysis can be carried out on a large scale. When a central energy island is used, multiple wind farms can be connected, resulting in economies of scale. The infrastructure consists of:

- A sand island or a caisson-retained island, which for 12 GW would be around 80 ha, equipped with:
    - Electrolysers and peripheral systems
    - A compression facility
    - HVAC equipment and switches
- A hydrogen pipeline (for a 12 GW scenario, we assume 36 inch) from the energy island to the mainland
- Inter-array cables to connect neighbouring wind farms to the island
- 1 GW HVAC stations and HVAC cables to connect wind farms located further away to the island

It is also possible to design energy islands that facilitate the supply of both electricity and hydrogen. Section 6.1.4.5 examines the value of this type of connection.

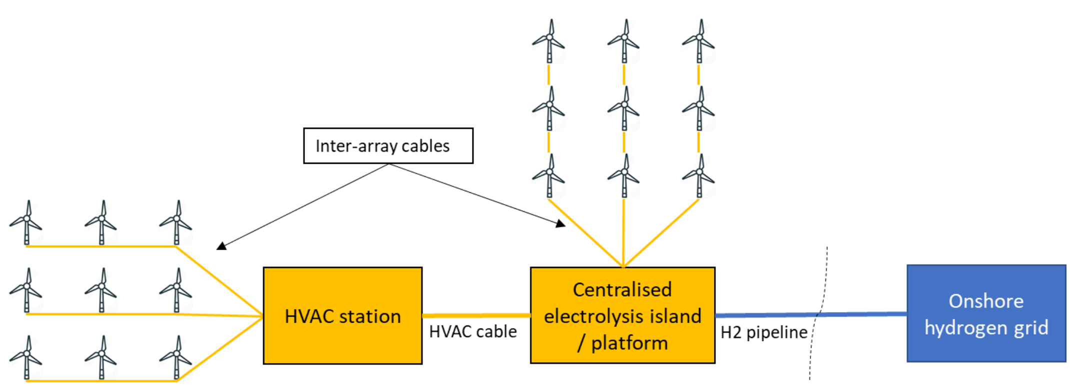


Figure 9: Schematic overview of electrolysis on an energy island

Hydrogen transmission via an offshore electrolysis platform

Another method for centralised offshore hydrogen production is to install electrolysers on one or more new platforms and connect wind farms to them. However, a platform will only have limited space for electrolysis capacity. In this study, we assume a maximum electrolysis capacity per platform of 500 MW. If there are several platforms, it is possible to connect all of them to a single pipeline to land.

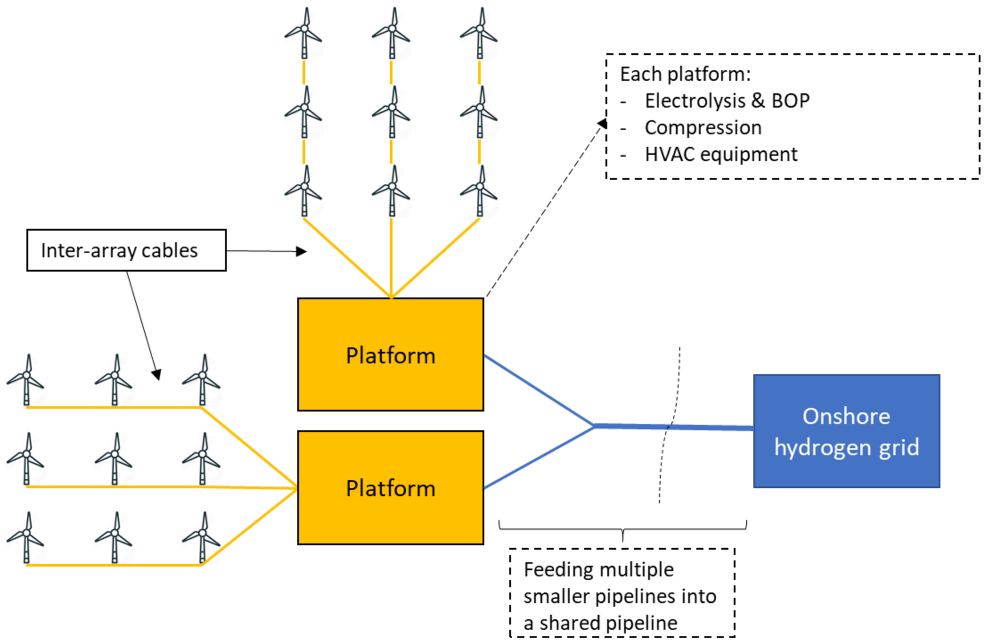


Figure 10: Schematic overview of electrolysis on an offshore platform

Hydrogen transmission based on integrated electrolysis

A final option is to integrate hydrogen production into wind turbines. This would involve installing the electrolysis equipment on the foundation platform, in the nacelle, or in the tower of the wind turbine. Hydrogen produced by different wind turbines is transported to a compression platform through small pipelines. A large pipeline then leads from this compression platform to the coast.

Integrated electrolysis results in a different ratio of wind farm costs to infrastructure costs. This can enable wind turbine designers and wind farm developers to search for new optimal solutions and potentially produce more energy per km^2.

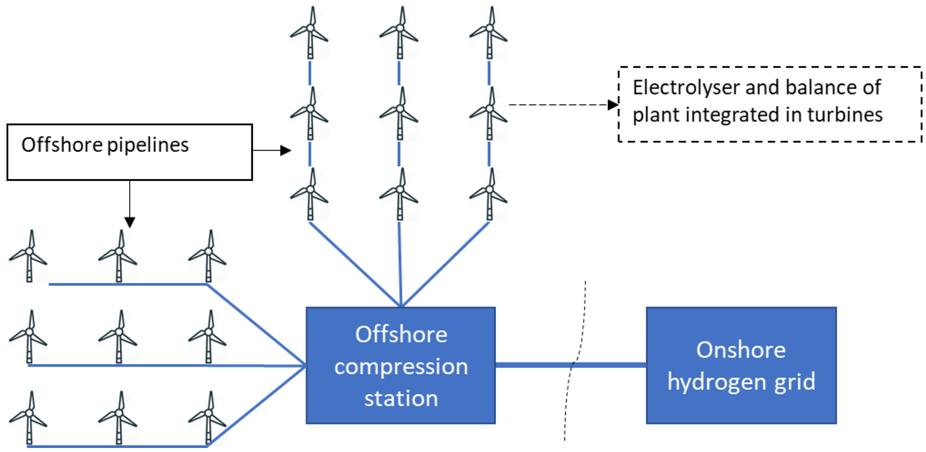


Figure 11: Schematic overview of integrated offshore electrolysis

Break-out 2: re-use of existing offshore infrastructure

Re-use of existing offshore gas infrastructure for hydrogen transport is enabled by offshore electrolysis. Search areas 6 and 7 are of particular interest for application of offshore electrolysis within the context of this study, due to the large distance to shore and potential for large-scale development.

Existing O&G production platforms may be suitable to host hydrogen compression and treatment installations. However, these are unsuitable for large-scale electrolysis installations.

The cost of converting natural gas pipelines to accommodate hydrogen transport is estimated to be just 10 to 35% compared to developing new pipelines (European Hydrogen Backbone, 2021). This could result in a cost savings of 2%, considering the total infrastructure costs for 12 GW offshore electrolysis. Another, possible more valuable, advantage is the re-use of the pipeline route. Re-use of offshore pipelines for hydrogen transport does require a change in permit.

There's no upfront guarantee that existing pipeline can be retrofitted for hydrogen transport. Pipelines may be contaminated by hydrocarbons in the gas that it currently transports. In addition, there's no public information available on the current state of the pipelines. Further research is required to assess the effects of pressure variations caused by fluctuating input, placement of extra seals/valves to avoid major pressure drops, and blending of oxygen to avoid embrittlement of pipelines. Furthermore, multiple production platforms depend on the availability of the pipelines, and it is uncertain when the pipeline becomes available for the transport of hydrogen. If a pipeline can be re-used, additional measures must be taken to accommodate hydrogen transport, such as adjustment of the onshore metering location and the adjustment of safety measures.

A connection from search area 6 to the existing NOGAT pipeline is of particular interest. The pipeline is in the proximity of the search area, lands in Den Helder, and as a significant capacity. The WestGas Transport pipeline lands in Den Helder as well, the Noordgastransportleiding lies a little further and lands in Eemshaven.

3.3 Onshore electricity infrastructure

Offshore wind energy is transmitted as electricity to the onshore high-voltage grid. This grid consists of 110, 150, 220, and 380 kV voltage levels, with almost all offshore wind connected to the 380 kV grid (see Figure 12 for the current grid, 380 kV grid in red). The electricity is transported further inland through the 220/380 kV network and distributed to the low and medium voltage grid of the regional grid operators through the 110/150 kV grid.

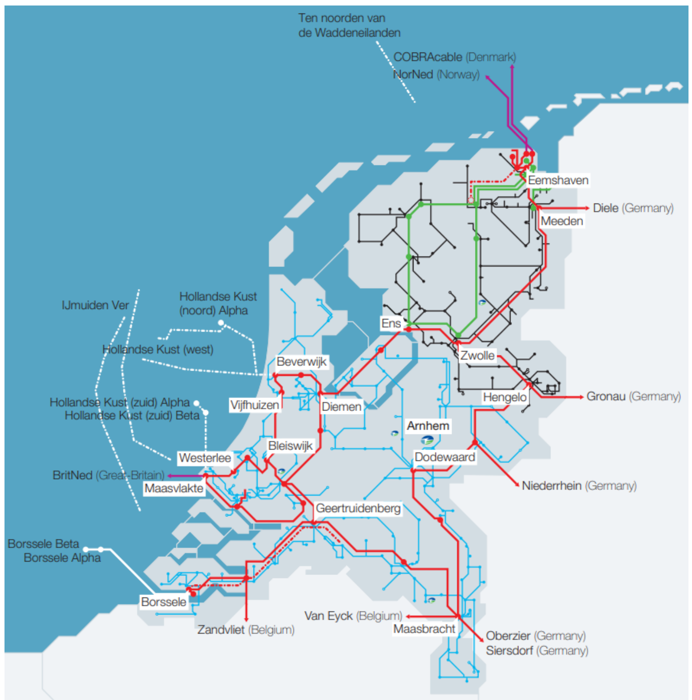


Figure 12: Current TenneT electricity grid (source: TenneT website)

A grid model is used to analyse the impact of different future offshore wind configurations on the network. This model represents the envisaged grid topology for the target year 2040. It consists of the current network plus approved projects to reinforce the grid which are due to be completed in the near future.

As well as approved projects, there are plans for a large number of infrastructure expansions (which are essential for landing offshore wind) that are still in the study phase. These are projects not yet been approved and for which, in many cases, the exact details are still unknown. It is uncertain if and when these projects will be started, and in many cases the start date would be after 2030. There may also be some projects which can be carried out before 2040 that are currently not yet in the picture, since the usefulness of and need for such projects will only become apparent in a later investment plan.

Given the nature of this study, it was decided to include these study projects in the envisaged network model[28]. It is essential to note, however, that this envisaged grid model will probably only be realised around 2035, and that, in the time horizon 2030–2035, the potential landing of offshore wind largely depends on the realisation of these study projects. Key expansion projects that have been taken into account include:

- 380 kV connection between Eemshaven and Ens (NW380 phase 1+2)
- 380 kV connection between Borssele, Rilland, and Tilburg (ZW380 West+East)
- 380 kV connection between Borssele and Terneuzen and new 380 kV station at Terneuzen
- 380 kV station at Graetheide, connected to Maasbracht with two 380 kV circuits
- 380 kV station at Middenmeer, connected to a new 380 kV station between Diemen and Oostzaan with two 380 kV circuits
- 3rd 380 kV circuit for connections between:
    - Krimpen aan de IJssel and Geertruidenberg
    - Diemen and Lelystad
    - Lelystad and Ens
- Upgrade of almost the entire 380 kV grid to 4 kA
- Pocket structure for the majority of the HV grid (110/150 kV)[29]

The grid model for this study does not use a representation of the network in other countries, which is used for the investment plan. The power exchange between the high-voltage grid in the Netherlands and the grid in other countries is modelled in the form of power injections (positive or negative for import and export respectively) at existing border connections. These injections are distributed proportionally (and based on capacity) between border connections per country. Section 7.2.3 describes the implications of this simplification.

[28] The grid model therefore anticipates the model used by TenneT in its investment plan. Projects in the study phase are excluded from this list.
[29] In a pocket structure, the underlying 110/150 kV grid is cut down into sub-networks (pockets) that are all connected to a single 380 kV station. This avoids a situation in which large-scale transport, which should in fact all be transported through the 380 kV grid, is also partly transported in parallel on the 110/150 kV grid.

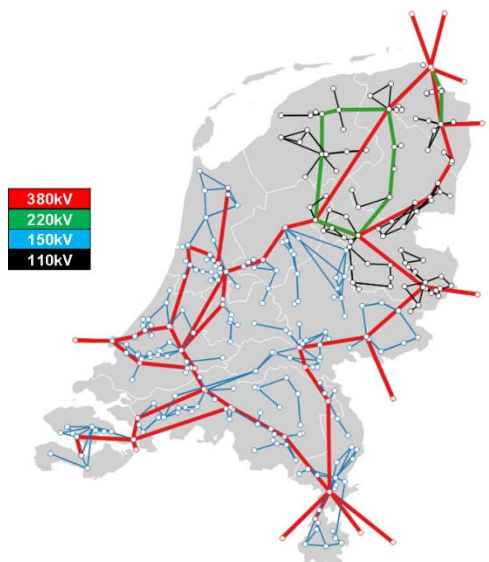


Figure 13: TenneT grid model for envisaged electricity infrastructure

3.4 Onshore hydrogen infrastructure

The future energy system in the Netherlands, including energy carriers used as a raw material in industry, must be climate-neutral by 2050 in order to meet the targets specified in the Paris Climate Agreement. II3050 outlines four diverse, climate-neutral visions for the future which all show that the role of CO_2-free hydrogen will increase (varying from 200 PJ to 900 PJ). Pipelines are the most appropriate solution for the efficient transport of these volumes of hydrogen. The Netherlands does not currently have a fully comprehensive national hydrogen transport network. However, it does have an extensive and intricate natural gas transport network. Demand for natural gas is expected to fall in the future, thus releasing transport capacity. The State Secretary for Economic Affairs and Climate Policy has asked Gasunie to develop a national hydrogen transport network, by releasing some existing onshore gas pipelines and making them suitable for reuse to help achieve a timely and cost-efficient energy transition.

To ensure the 2050 targets are met, the Government has also formulated targets and ambitions for 2030. The Climate Agreement announced a hydrogen programme that aims to have 3 to 4 GW of electrolysis capacity by 2030, with development being in alignment with growth of renewable electricity. The ‘Fit for 55’ package may have a significant impact on growth in the supply of renewable electricity.

Gasunie is focusing on the development of a national hydrogen transport network that can be operational before 2030. This transport network will be achieved in stages, and follows market trends in supply and demand: from connections to and between large industrial clusters to national connections and to hydrogen storage in the north and east of the country. Parts of this hydrogen transport network and hydrogen storage may become available in the period from 2023 to 2027.

Existing pipelines can largely (around 85%) be used for a nationwide hydrogen transport network; approximately 15% of the required hydrogen transport pipelines will need to be constructed. By 2030, the resulting connecting network (the 'hydrogen backbone'), which will be approximately 1000 km long, can also provide international transport to Germany (towards the Ruhr district and Hamburg) and Belgium (Antwerp), and be connected to large-scale energy production far out in the North Sea. The design of the national hydrogen transport network provides for 15 GW of transport capacity in 2030, with further increases to follow.

Capacity planning for the gas transport network will become more complex in the first instance, particularly in the transition phase where 'conventional natural gas' (of various qualities) is transported and stored alongside an increasing number of other gases. The hydrogen transport network can be realised in the period up to 2030 and further expanded as needed in the run up to 2050. Figure 14 shows a schematic depiction of a potential hydrogen transport network in 2030.

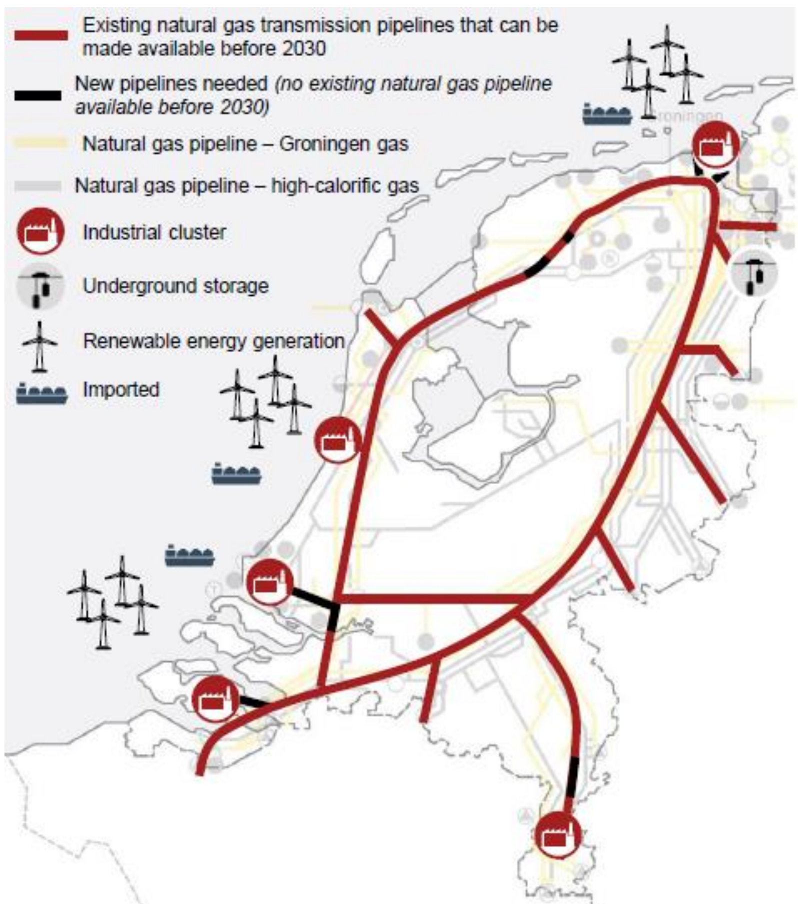


Figure 14: Outline of a potential hydrogen transport network in 2030. This map shows an east to west connection via Betuwe.

It is not clear at this time which part of the gas transport network will be used for hydrogen transport in 2040. What we do know, however, is what the national hydrogen transport network for transport between industry clusters and other countries may look like around 2030. This backbone, which is described in the HyWay27 study (Strategy&, 2021), is expected to provide sufficient transport capacity around 2030 and perhaps some years after that. We have also looked forward to the options for the hydrogen network in 2035. The network will grow between 2030 and 2035 in line with hydrogen supply and demand trends.

For the 2040 hydrogen network, a potential 2035 hydrogen network has been further expanded depending on the transport scenarios. Should the transport scenarios so require, this network can be equipped with compression to maintain sufficient pressure in the grid, providing additional transport capacity. The additional compression essentially takes place at existing locations of natural gas compressor stations.

The bottleneck analysis of the 2040 hydrogen network is based on the configuration shown in Figure 14.

Hydrogen is first and foremost expected to play a major role in industry, both in the Netherlands and neighbouring countries. The projected hydrogen network is in line with the routes in the current design for the 2030 hydrogen backbone. An obvious difference is the configuration of the hydrogen network, as taken as the starting point for this study, includes several rings and has more east-to-west connections than the original hydrogen backbone that can be operational by 2030.

4 Electrolysis

4.1 Current situation and vision for the future

General picture of the future role of hydrogen

The future of electrolysis depends on development on both the supply and demand side. The general picture is that the supply side is technically ready to scale up to larger demonstration projects. However, development of demand is a key precondition and is a bigger hurdle. The supply of green hydrogen is expected to increase between 2024 and 2035, however this depends on trends in the electricity market (ratio of renewable generation to base load demand) and on national and international policy instruments that are not yet entirely clear. The 'Fit for 55' package may lead to a shift in this outlook, for example by encouraging the use of hydrogen in aviation and shipping. Part of this package is the Renewable Energy Directive II (REDII), which imposes a target of 50% use of renewable fuels of nonbiological origin (RFNBOs) as fuel or raw material in industry by 2030. The precise impact of the 'Fit for 55' package and REDII requires further analysis.

Onshore electrolysis

Onshore electrolysis is a proven technology that has been used in industry for a number of decades. In the 2020 SDE++ round, support was granted for an initial 2 MW electrolysis project, with more and larger electrolysis projects expected in the 2021 round. A direct connection between an electrolyser and a wind farm (coupled electrolysis) results in a hydrogen supply profile equivalent to that of the offshore wind farm. It is also possible connect an onshore electrolyser to the electricity grid, which means the number of full-load hours for the electrolyser is not limited by the offshore wind farm. The use of by-products such as waste heat and oxygen in industrial processes can increase system efficiency. Solid oxide electrolysis (SOEC) can use industrial waste heat to reach high temperatures, and thus achieve higher efficiency.

The main challenge is the space needed, often in an already densely populated coastal region.

Offshore electrolysis

Offshore electrolysis is possible via two development paths: centralised and decentralised (integrated). Centralised involves constructing an electrolysis facility on a platform or an artificial island, connected to wind farms by cables. Decentralised means that electrolysis is integrated into the wind turbine, positioned on the foundations, the tower, or nacelle. In the context of this study, a market consultation was carried out to gather the latest views of developers and manufacturers on the feasibility of both forms of offshore electrolysis.

Centralised offshore electrolysis currently appears to be a more mature technology than the integrated variant. There are two main reasons for this: firstly, the offshore industry has extensive experience of offshore platforms, and secondly, no changes need to be made to wind turbines or the wind farm layout. Additional benefits include easier maintenance due to the centralisation of all components, not having to duplicate sub-components such as demineralised water generators, and the ability to transport both hydrogen and electricity to shore. There are also advantages in terms of infrastructure: the construction of a new pipeline is more cost-effective than a cable at high capacities, and no electricity is lost in the transport to land. A disadvantage of the centralised option is that large wind farms may need several electrolysis platforms (500 MW of electrolysis capacity per platform) at considerable costs.

Electrolysis integrated into wind turbines has implications in terms of the required infrastructure. The turbines need to be connected with 'inter-array' pipelines to a platform where gas treatment and compression takes place. This platform is then connected with pipelines to the national hydrogen network. A hybrid connection, which enables landing both electricity and hydrogen, is more difficult to achieve for this concept. Integrated offshore electrolysis is less mature, as it requires new design and certification of wind turbines to maximise the benefits of hydrogen integration. Nevertheless, a number of wind turbine and electrolysis manufacturers were particularly optimistic about integration into or near to individual wind turbines, referencing two key advantages:

1. Integrating the entire electricity chain from generator to electrolyser stack allows the omission of various electrical components of wind turbines and electrolysers, thus reducing electrical losses (by 5–10%) and capital expenditure.
2. Switching the transmission infrastructure from electricity to hydrogen changes the financial implications. This enables wind turbine designers to search for new optimal solutions in relation to rotor size and generator capacity, which can generally mean more energy is produced per km^2.

Despite manufacturers' enthusiasm for integrated electrolysis, a number of project initiators believe it is too early to say whether centralised or decentralised offshore electrolysis, integrated or otherwise, will be the most cost competitive. Centralised electrolysis offers more interconnection capability to connect different energy hubs (both electricity and hydrogen interconnection is possible) and could give the option to achieve more full-load hours with the offshore electrolysers.

A number of offshore electrolysis demonstration projects have been announced, such as the OffShoreH2 initiative (Nationaal Groeifonds, 2021). Based on the interviews and literature study, the first GW-scale offshore electrolysis projects are expected by the end of this decade or the start of the next decade, with large-scale operation between 2030 and 2035. The reasons behind this long range are the low level of maturity of the technology, the technical challenges, and the uncertainties inherent with 10–15 year time scales.

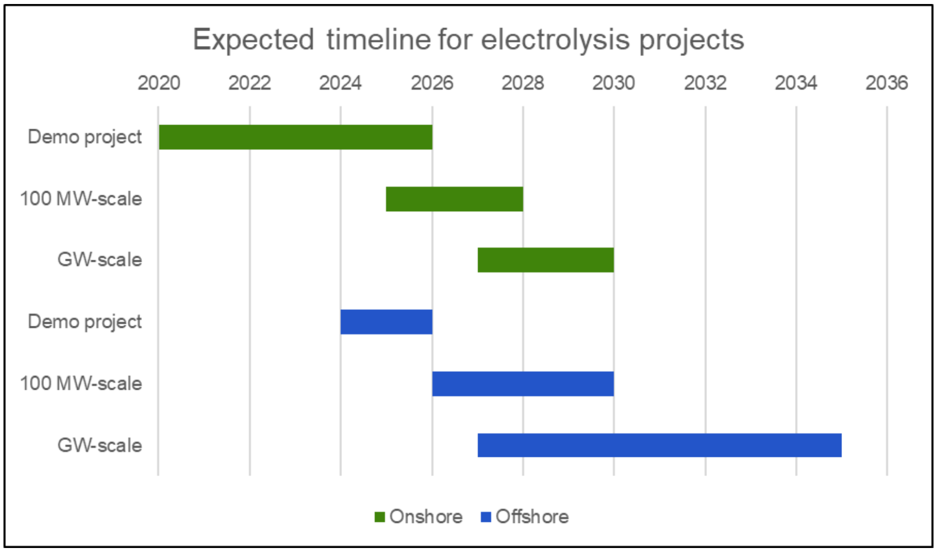


Figure 15: Expected timeline for onshore and offshore electrolysis projects on various scales

Electrolysis technology

Proton Exchange-Membrane (PEM) electrolysers are considered the most promising technology for offshore applications: they promise high efficiency and a low volume/footprint over time and are able to cope with a fluctuating power supply. Nevertheless, several market parties do not write off competing technologies: alkaline has been further developed (mainly relevant for onshore application, although alkaline electrolysis at higher pressure may also become relevant offshore) and solid oxide electrolyser (SOEC) technology can have greater integration benefits in an industrial environment.

Market parties find it difficult to estimate how quickly electrolysis will start to fall on the cost curve. There is an opportunity to cut costs by increasing the stack capacity, but economies of scale are generally expected to play a greater role in Balance of Plant and engineering, purchasing, and construction costs. Greater installed capacity at global level will also lead to learning effects, and the supply chain will become more mature and more efficient.

Feasibility of offshore electrolysis

<u>Challenges</u>

No 'showstoppers' have been identified in relation to the development of offshore electrolysis. A number of technical challenges need to be overcome, the most important of which are:

- Current wind turbines are not designed for off-grid operation and require a base load to operate.
- Electrolysers need temperature regulation to prevent freezing in cold conditions with low wind speeds. Freezing would result in failure.

These challenges apply to offshore electrolysis that is only connected to offshore wind farms. In the case of a hybrid connection to land (with both an electricity and hydrogen pipeline connection), wind turbines have access to a constant supply of electricity and temperature regulation is possible during periods of low wind speeds.

Conditions

Interviewees imposed a number of conditions on the realisation of offshore electrolysis, of which policy-related conditions are set out in the 'Policy solutions' section below. The other main conditions identified are as follows:

- A clear roadmap for hydrogen transport and seasonal storage, along with purity standards for hydrogen in the system.
- The realisation of offshore means of transmission (e.g. pipelines to shore) could result in long lead times, potentially making them a critical element of the development path. Planning and permitting processes for infrastructure must start well before they do for a wind farm.
- A clear, major pipeline of projects is needed so investment decisions can be taken in relation to the design, certification, and construction of the entire value chain.
- Uncertainty with regard to hydrogen prices means large projects lasting 20+ years are difficult to justify and project developers, buyers, or the Government need to limit the financial risks.

4.2 Implications for policy

In the future, offshore electrolysis may be a cost-effective method of transporting offshore wind energy to land. A number of steps need to be taken before this can be implemented on a large scale. Based on the interviews and expert assessment, the following implications have been identified for policymakers:

- Both centralised and integrated offshore electrolysis are expected to be technically feasible by the start of 2030. There is currently no consensus regarding the most cost-effective method, as this is partly dependent on the specific project (e.g. wind farm size, distance from the coast, and the possibility of interconnection). Both concepts are in development: the first centralised small-scale demo projects are expected in the short term, while integrated offshore electrolysis along the value chain is being explored and may have significant value (reduction in costs and electrical losses, optimised wind farm design). It is therefore sensible to consider both variants in their development, including the facilitation of demonstration projects.
- Policy is considered a driving force behind the realisation of the first projects. Some parties make a clear distinction between before and after 2030, whereby dedicated instruments may be necessary for economic feasibility by 2030. Some parties support large-scale demonstration projects and 'learning-by-doing', whereby solutions are sought as work progresses and cost reductions can be achieved.
- Current support schemes are deemed insufficient to raise the financing needed for offshore electrolysis. The scope for solutions involving policy on the supply or demand side and grants needs to be examined to identify the best policy instruments to accelerate the development of offshore electrolysis
- It is advisable to examine cost sensitivities when comparing different types of electrolysis, taking into account the uncertainty of future cost levels.

4.3 Electrolysis operating options

Electrolysis can be used in a variety of ways, which all affect its impact on the energy system, the number of full-load hours of electrolysers, and the volume of hydrogen produced. This study analysed three different modes of operation for electrolysis. In each case, electrolysis is used to meet all or part of the demand for hydrogen in different sectors, plus exports; the modes of operation have been defined in order to serve a system function.

1. **Electrolysis in the event of surplus sustainable energy production**

At times when significant amounts of sustainable energy are being produced, potential supply can exceed demand for electricity. At these times, electrolysis can be a valuable use of the surplus, alongside exports and electricity storage. The modelling calculates the hourly residual demand (electricity demand minus supply): if negative (supply exceeds demand) this is the maximum volume of electricity that can be used for electrolysis. Economic optimisation is then used to determine optimum electrolysis capacity (see chapter 5.7).

This form of electrolysis is installed on land. Due to regionalisation, the majority of this capacity will be located near offshore wind energy landing zones.

2. **Electrolysis that tracks offshore wind energy production**

In the event of structural congestion, pressure can be taken off the grid by using part of the offshore wind capacity to produce hydrogen. In this case, electrolysis tracks the offshore wind energy profile. This reduces grid congestion and increases the number of electrolysis full-load hours, but, at the same time, means not enough sustainable electricity is always produced to meet demand for electricity, whilst hydrogen is still being generated. This form of electrolysis can be done offshore or onshore near to the offshore wind energy landing point. The use of this form of offshore electrolysis has implications for offshore infrastructure, as pipelines need to be used to bring the hydrogen gas to land. If used at the landing point, the only offshore infrastructure is electrical. Both offshore and onshore use have similar impact on the system, but are associated with different infrastructure costs (e.g. cables and pipelines). This type of electrolysis has implications for the wind farm and electrolyser operators, as there is no flexibility to choose between supplying electricity or hydrogen. It should be noted that congestion management is a temporary, market-driven, non-discriminatory solution to grid congestion, to bridge the time it takes to expand the network. The use of electrolysis to avoid structural congestion is therefore dependent on a review of the policy framework for congestion management.

3. **Electrolysis to prevent grid congestion**

Where electrolysis is used to prevent grid congestion, operating behaviour can be refined compared to the full tracking of offshore wind energy production. At times of low wind energy yield, it is desirable to feed all electricity into the grid. To avoid congestion, electrolysis can be used above a set upper limit.

An iterative rough estimate has been made of the maximum wind energy capacity that can be fed into the electricity grid for the different offshore wind energy landing zones. The same applies to this form of electrolysis, as to the second principle (electrolysis that tracks offshore wind energy production):

congestion management is currently a temporary, market-driven, non-discriminatory solution to congestion.

Onshore electrolysis has been added for locations where the amount of offshore wind energy landed exceeds this maximum capacity. Electrolysis is activated at times when more wind energy is produced than can be transported via the grid. A 'cap' or upper limit is therefore applied to the amount of wind energy that can be transported inland. This mode of operation can be implemented onshore or offshore.

The operating behaviour for the second and third forms of electrolysis is presented in Figure 16, which shows that the production profile for coupled electrolysis (blue) takes the same form as the profile for offshore wind energy. Here, 2 GW of electrolysis capacity is coupled to a 2 GW wind farm. In the case of electrolysis to prevent congestion, only the offshore wind energy that exceeds the feed-in limit is used for electrolysis. The orange production profile in Figure 16 is therefore equivalent to the offshore wind energy profile *above* the feed-in limit.

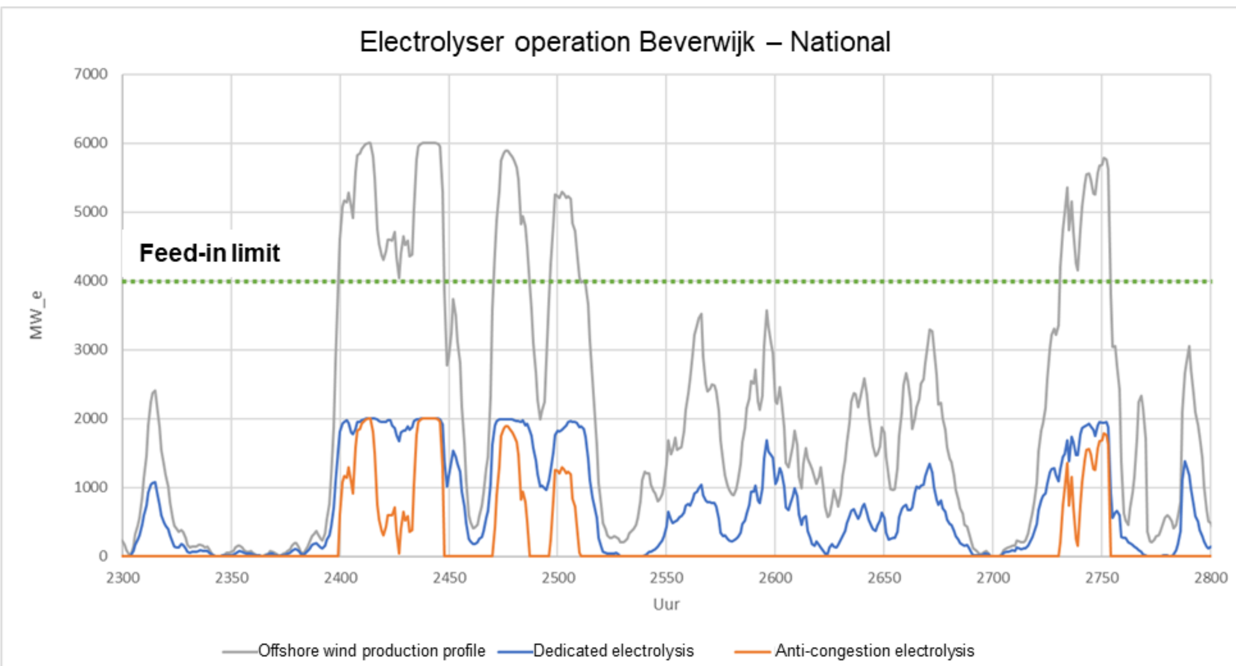


Figure 16: Behaviour comparison for 2 GW of coupled electrolysis capacity (blue) and 2 GW of electrolysis capacity which activates when the feed-in limit is exceeded (orange).

Offshore electrolysis can be used according to the second principle (electrolysis that tracks offshore wind energy production). However, it is also possible to create a hybrid connection to land consisting of both a hydrogen pipeline and an electricity transmission cable. This removes part of the challenge associated with offshore electrolysis, enables wind turbines to be run on base load from the national grid, and ensures that heat regulation from offshore electrolysis is not dependent on the wind farm. A distinct advantage of a hybrid connection to land is the flexibility it gives the operator to supply electricity or hydrogen. The benefits of a HVDC connection to land as an addition to a power-to-gas island is discussed further in section 6.1.4.5.

5 Approach to offshore wind system integration analysis

5.1 Overview of approach

The impact of feeding in offshore wind energy on the energy balance, electricity grid, hydrogen network, and flexibility requirements has been analysed. Economic optimisation on the electrolysis capacity has also been carried out and the costs of offshore infrastructure have been calculated.

An iterative approach has been formulated: learning points from each analysis run have been fed back and used to define a new landing configuration.

The analysis can be divided into five main blocks, as shown in Figure 17:

1. Drafting of the 2040 scenarios and implementation in the Energy Transition Model (ETM)[30]: the electricity and hydrogen demand and supply scenarios (see chapter 2 for information on how the scenarios have been devised) were entered into the ETM. The ETM generates highly detailed hourly profiles for the various demand and supply sectors.
2. Energy flows and regionalisation: the national demand and supply profiles from the ETM were supplemented with offshore wind energy production profiles (electricity and hydrogen). The profiles were assigned to regions in the Netherlands, according to an allocation formula (regionalisation).
3. Flexibility analysis: the need for and use of flexibility options was analysed based on the national supply and demand profiles. The starting point of the flexibility analysis is the continuous energy balance in the electricity, methane, and hydrogen system.
4. Grid congestion analyses: analyses were carried out to determine the impact on the electricity grid and gas network based on the results of the regionalisation and the flexibility analysis. The congestion results from the electricity grid analysis were then used to determine the next landing configuration.
5. Electrolysis optimisation and offshore infrastructure costs: finally, the results of the previous steps were used in the electrolysis optimisation calculation. The offshore infrastructure costs and the impact on the system (power-to-gas, gas-to-power (G2P), import and export operating behaviour) were determined in parallel.

The analysis was carried out in close collaboration with Gasunie and TenneT, which applied the models from the II3050 approach.

[30] The Energy Transition Model is an independent, open-source model for the drafting and analysis of energy scenarios. https://energytransitionmodel.com/

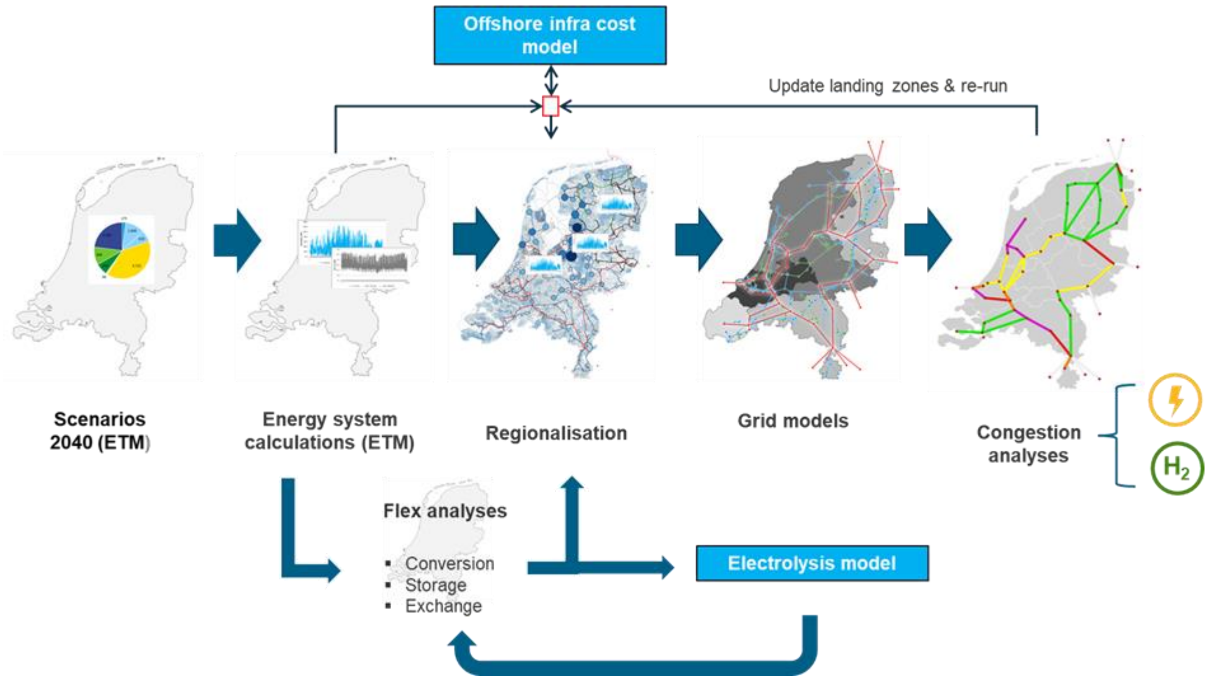


Figure 17: Schematic depiction of the model chain

5.2 Background to II3050

In April 2021, TenneT and Gasunie published the main report for the Integrated Infrastructure Outlook 2030–2050 (II3050), together with the regional network operators in the Netherlands. This exploratory study paints a comprehensive picture of the Dutch energy system in 2050, in the form of four different scenarios, examining the potential implications in terms of infrastructure required in the period 2030–2050 across sectors and different energy carriers. In addition to drawing up scenarios, the parties also carried out a number of methodical steps (energy system calculations, flexibility analysis, and regionalisation).

Hourly profiles for various energy production technologies (such as wind and solar PV) and applications on the demand side were first determined. The use of flexible tools such as curtailment, conversion, storage, and energy exchange with other countries was then agreed, with the main objective of achieving balance between supply and demand within the energy system at any time of the year. Locations in the Netherlands were also selected for supply, demand, and flexible applications, taking into account a number of criteria, including current locations or the available spatial potential.

The profiles established for each location were used as input for the grid analyses, which calculate the required transport of energy between regionally differing supply and demand. Detailed documentation of the methodological steps and the underlying model assumptions can be found in the report and its appendices (Netbeheer Nederland, 2021).

Whereas II3050 focuses mainly on onshore infrastructure, the Offshore Wind System Integration 2030-2040 study is a logical extension of the issues surrounding the development of offshore wind and associated offshore infrastructure. For this reason, and due to the comprehensive nature of both studies, the project consortium decided to broadly use the same methodology and model choices for the onshore analyses as in II3050 and only develop them further where necessary. For example, location-specific offshore wind profiles have been used in this study instead of a national production profile to better take into account regional differences in available wind and to facilitate variations on the respective profiles.

The offshore wind energy production profiles were used as input for the II3050 model chain. The calculated application profiles for the flexibility tools (exchange with other countries, batteries, curtailment, flexible gas-fired power plants) then served as input for the grid analyses (see chapter 5.6) and optimisation of electrolysis capacity (see chapter 5.7).

5.3 National demand and supply profiles (ETM)

The ETM (open source) describes the Dutch energy system as a whole, distinguishing between different sectors such as agriculture, transport, industry, and energy. The ETM models current and future national supply and demand profiles on an hourly basis. These hourly profiles are used and optimised in other phases of the model chain.

The two IP2022 scenarios and the four II3050 scenarios are available in the ETM, however no information is yet available for the four selected 2040 scenarios. The first step in the model chain was therefore to add the four basic scenarios for 2040 – Regional, National, European, and International (plus two variants) – to provide hourly profiles for each energy carrier and sector in each scenario in 2040.

Chapter 2 describes how supply and demand of energy carriers and sectors has been interpolated for 2040. The ‘development factors’ drawn up for this purpose – which determine how the energy carriers/sectors will develop in the 2030-2050 period – have been used as input to process scenarios in the ETM based on more than 300 parameters in the model. This was done in two phases. The Berenschot-ETM-API first applied the development factors for a sector to all parameters associated with that sector. The correlation between the results (e.g. electricity demand) and the values in the interpolation model was then examined. In the event of a significant deviation, certain parameters were corrected manually, such as the presumed efficiency of a heat pump, to achieve a good ‘fit’ between the 2040 scenarios modelled in the ETM and the values in the interpolation model.

Given this study focuses on the energy balance of hydrogen and electricity, no interpolation was carried out for other energy carriers. As a result, the scenarios in the ETM are not a full calculation of the situation (in four scenarios) in 2040 and it is impossible to determine total CO_2 reduction for 2040. If a reduction target is defined for 2040 in the future, the CO_2 reduction achieved can be determined in the same way as for II3050 and the ETM scenarios for 2030, by means of a more complete interpolation or a bottom-up approach.

5.4 Regionalisation of onshore demand and supply

The assumptions regarding future supply and demand locations, in addition to volumes and usage, play a decisive role in terms of the use of flexibility tools and the national and regional transport networks. This applies to both the national component and landing of offshore wind energy.

As described in section 5.2, as in II3050, decisions have been made in this regard for each supply technology and demand application in the context of this study, largely on the basis of public data sources and objective criteria. A full list can be found in the appendix document (appendix F) for the II3050 study (Netbeheer Nederland, 2021). The regional allocation formulas were consistently collected at neighbourhood level and then linked to stations in the electricity and hydrogen grid based on knowledge of the underlying grid topology. Multiplying the profiles gathered in a previous step by the respective allocation formulas resulted in profiles that show the capacity produced or required per hour and per station. These profiles are then used to determine regional distribution of the flexibility tools (section 5.5) and to perform the grid analyses for the electricity and hydrogen networks.

5.5 Regionalisation and use of flexibility options

Regionalisation and use of flexibility tools were applied according to the principles used in II3050. Where the regionalisation determined supply and demand locations, as described in the previous section, the location of flexibility tools was not specified, therefore allowing freedom of choice. The chosen locations of flexibility tools primarily limit the impact on the electricity grids. This means, depending on the imbalance, system batteries, peak load power stations, and P2G plants are located close to the supply or the demand. Surplus electricity can be converted into hydrogen by means of P2G at these locations. Hydrogen is then transported via the gas infrastructure to the demand or storage location.

The opposite applies to shortages: gas (hydrogen or methane from storage facilities) can be converted into electricity. The gas infrastructure is therefore used to provide the energy system with flexibility. Surplus electricity can also be temporarily stored on site in batteries; in times of shortages, these batteries can then discharge. This strategy probably has the lowest impact on the electricity grid. In the flexibility analysis, gas/hydrogen storage is typically used as a seasonal buffer and the batteries for shorter periods. No economic optimisation was carried out in the flexibility analysis, however battery volume (MWh) was balanced against electrolysis capacity (MW)[31]. This electrolysis capacity is optimised again at a later step in the modelling; see section 5.7.

In accordance with II3050, the following principles apply to the specific flexibility tools:

- The energy balance is maintained on an hourly basis, for the electricity, gas, and methane systems. The behaviour of each flexibility option is optimised, allowing them to be deployed when necessary to maintain balance in the system.
- Large-scale power stations are located at the current sites of large power stations.

[31] For batteries, achieving volume (MWh) is expensive, but achieving capacity (MW) is relatively cheap. The opposite applies to electrolysis.

- Peak load power stations are distributed in proportion to regional peak deficits in the areas near to electricity demand.
- P2G is provided mainly in areas with high production or landing of renewable energy (areas with a sustainable energy supply that exceeds energy demand). This distribution is plotted in proportion to regional maximum surpluses.
- System batteries are located next to all offshore wind energy landing zones and at all connections between the regional and national electricity grid, with volume determined by the regional balance between supply and demand.
- Electricity imports and exports to other countries are distributed according to the current and planned location of the cross-border interconnection (380kV).
- Gas imports and exports are distributed according to current and future plans for cross-border connections.
- Methane or hydrogen gas storage locations are underground, whereby the storage potential has been estimated based on geological characteristics.

The exchange of electricity with other countries has been modelled as follows: The Netherlands forms part of the integrated European energy system with electricity connections to Germany, Belgium, Denmark, Norway, and the United Kingdom. This means electrical power is exchanged between neighbouring countries depending on the respective supply and demand situation at any given time. The maximum import and export potential is limited by market exchange capacity, which is determined by both the capacity of the direct physical connections (line connections, cables) between the countries as well as the infrastructure within the countries. Market exchange capacity is expected to grow in the future due to increasing market integration and reinforcement of the European transport infrastructures. This study takes into account approximately 15 GW in electricity market exchange capacity[32] between the Netherlands and its neighbouring countries, based on European studies (entso-e, 2021). To determine actual exchange between the countries, the first step was to calculate whether there is an overall surplus or shortage of electrical power in a given hour (residual demand) for each neighbouring country. Countries with an electricity surplus can then supply to neighbouring countries with a shortage and vice versa, taking into account respective maximum market exchange capacity.

For an overview of the results of the flexible modelling and electrolysis optimisation for all scenarios and solutions[33], see appendix C, Table 21 to Table 25. These tables clearly show the interplay between curtailment, electrolysis, gas-fired power plants, batteries, and import/export of electricity.

[32] The market exchange capacity is markedly less than the physical capacity, as it needs to take into account factors such as the countries' transport infrastructures and safety margins.
[33] For an explanation of the term 'solutions', see chapter 6

5.6 Grid analyses

5.6.1 Electricity grid analysis

Congestion analyses were carried out to analyse the impact of different offshore wind energy landing configurations on TenneT's high-voltage network. This analysis investigated the load on the grid components by specifying all components in the grid model with a permitted load capacity. If the calculated transport of electricity on a circuit or a transformer exceeded the maximum load capacity, this was recorded as a capacity bottleneck.

The congestion analysis is a year-round calculation, which means network calculations were performed for 8760 hours in the year. To do this, supply, demand, and flexibility data for each power station was read in for all these hours for the target year 2040. Power flow simulation software was used to calculate how the electricity is transported across the various components from the supply to the demand per hour using a DC (direct current) power flow, which is an approximation of the AC (alternating current) power flow. All power flow simulations are N-1 calculations, which means the load on a component was determined at the time that another component (with the largest impact on the first component) was unavailable.

One of the methods used to quantify the severity of the bottleneck is an energy-not-transported indicator (ENT indicator). This indicator has been determined for each relevant grid component (connections and transformers) and is defined as the sum of the power current minus the maximum load capacity of the network component for all hours in which the power current exceeds the maximum load capacity. For each connection, this indicator therefore shows the annual amount of energy that cannot be transported due to a shortage in transport capacity, providing an indication of both the frequency and level of overloads. This indicator is illustrated in Figure 18. As a very rough estimate, it is assumed these bottlenecks can be resolved operationally with redispatch, for a cost of €100/MWh ENT[34]. Redispatch involves limiting power input at a location while increasing power input at another location, to relieve the burden on part of the grid.

[34] This is based on current costs of redispatch, which could be higher in the future.

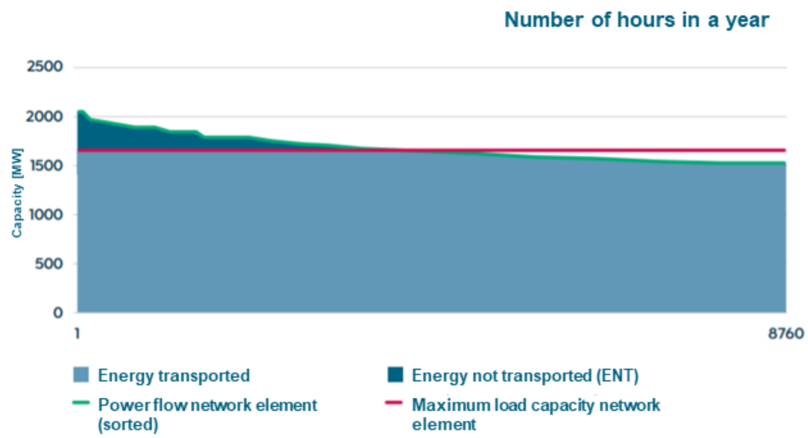


Figure 18: Schematic depiction of ENT

The impact of various offshore wind energy landing configurations on TenneT's Ultra-High-Voltage Grid (UHV, 220/380 kV) has been determined for the purpose of this study. The results are presented in the form of grid maps, like the one in Figure 24, in which all connections of the UHV grid are coloured according to the load on the connections. Roughly speaking, it is assumed no new infrastructure will be provided for a connection with an ENT of less than 0.1 TWh/year (approx. €10M/year). In these cases, an operational solution is more cost-effective than the creation of additional infrastructure. Connections with an ENT of 0.1–0.25 TWh/year (approx. €10–25M/year) have higher operating costs. Given the uncertainty of the scenarios and potential congestion management options, however, an expansion of the infrastructure is probably not necessary at this time. In the case of an ENT of 0.25–0.5 TWh/year (approx. €25–50M/year), it depends on the situation whether an operational or infrastructure solution is preferable. In the case of an ENT of 0.5 TWh/year or above (approx. €50M/year), additional infrastructure is desirable in most cases.

For each hour of the year, the load on a connection can be shown in relation to the various causes of congestion, for example the amount of energy from offshore wind or the use of P2G. One example of this is Figure 19 for the Eindhoven–Maasbracht connection. This figure shows the correlation between offshore wind electricity (y-axis), the use of P2G (colour scale), and load on the route (x-axis). Figure 19 illustrates that a significant overload occurs on the 380 kV connection between Eindhoven and Maasbracht; in the worst case, 6000 MW is transported, whereas the maximum load capacity for the connection is 2650 MW (see red dotted line). This overload occurs in hours when there are strong winds, but the electrolysers close to the coast are not or barely operating (yellow and green colours). These are situations in which high offshore wind energy production (around 35 GW) coincides with a high demand in both the Netherlands and other countries, which means that the flexibility tools designed to balance supply and demand (P2G, batteries) are not used. The result is large volumes of offshore wind energy need to be transported through the high-voltage grid.

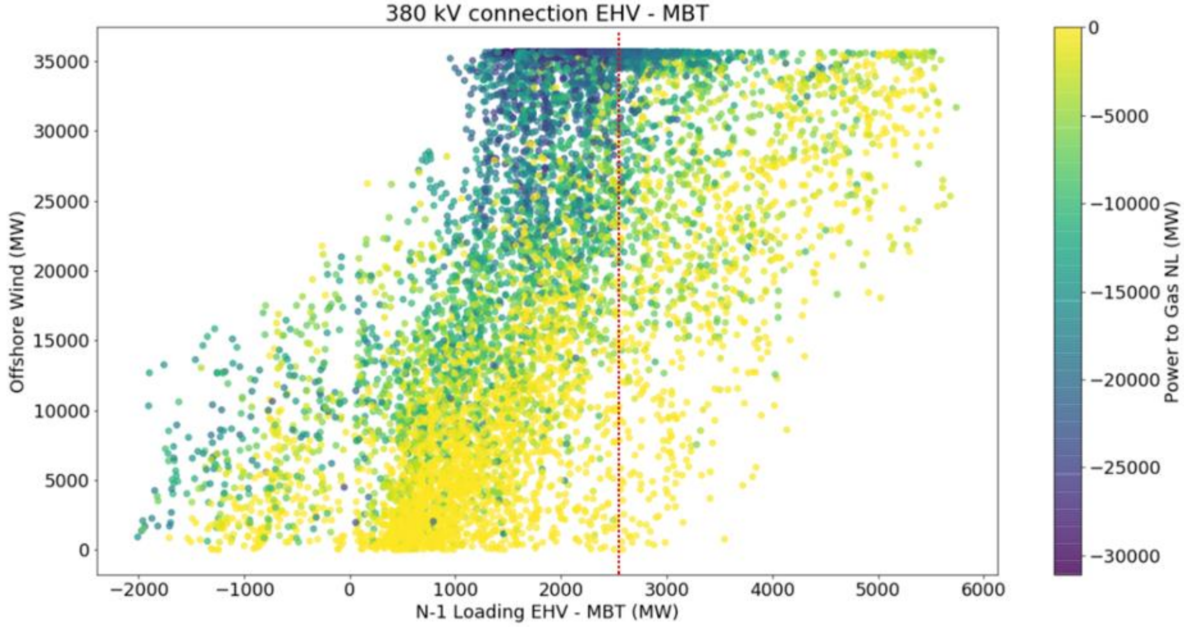


Figure 19: N-1 load ratio of offshore wind to power-to-gas at the Eindhoven–Maasbracht connection for the 38.5 GW configuration in the direction of Eemshaven

A second example to identify the cause of congestion is the relationship between offshore wind energy and the interconnector between the Netherlands and the United Kingdom from Maasvlakte; see Figure 20. This figure shows the correlation between offshore wind electricity (y-axis), transport via the UK-NL interconnector (colour scale), and load on the route (x-axis). The figure illustrates that the largest overload occurs in hours when the maximum import is 3 GW (1 GW from the existing BritNed interconnector and 2 GW from the new interconnector) and a large amount of offshore wind energy is being landed. Given it is more realistic that this interconnector is in fact a wind connector, the loads on the connections around Maasvlakte are probably somewhat lower than reflected in the results.

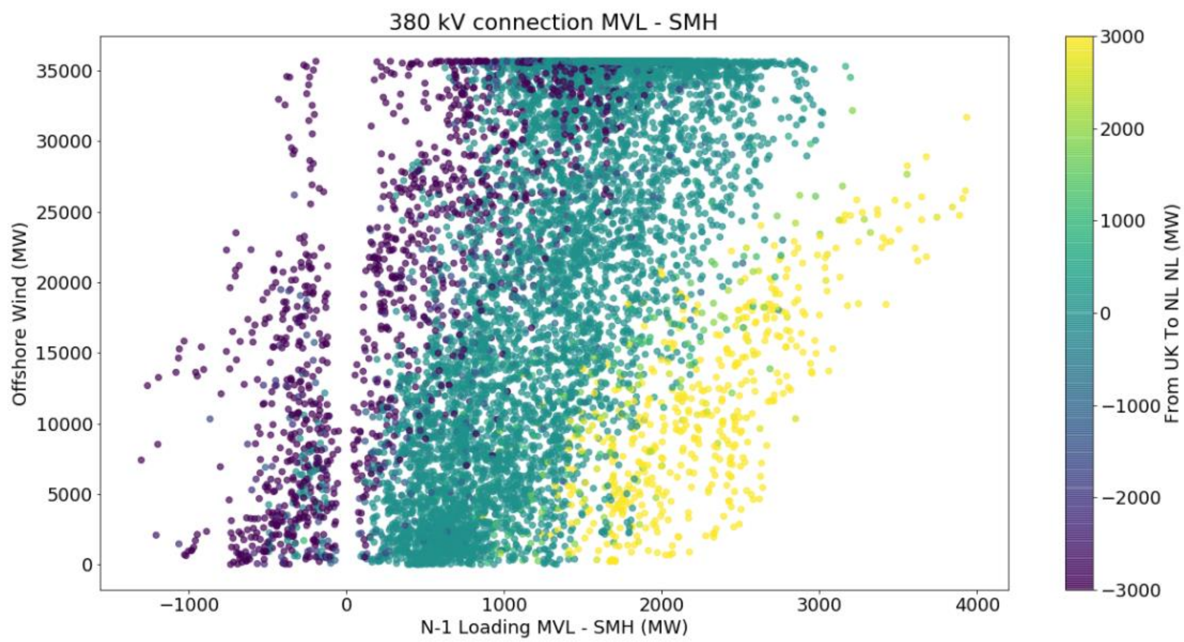


Figure 20: N-1 load ratio of offshore wind to import/export to/from the United Kingdom at the Maasvlakte–Simonshaven connection for the 38.5 GW configuration in the direction of Eemshaven

5.6.2 Hydrogen network analysis

This study explores the impact of variations in supply and demand scenarios and landing zones on the required hydrogen infrastructure. Network analyses were carried out for the 2040 hydrogen transport network, but not for the natural gas transport network. As a result, it is impossible to say whether additional natural gas pipelines can be reused or whether new hydrogen pipelines need to be constructed and/or additional compression needs to be installed.

Gasunie Transport Services’ existing national natural gas transport grid is made up of two parts: a high-pressure grid (HTL) and an intermediate-pressure grid (regional grid, RTL). The HTL transports gas over large distances with a pressure of between 80 and 40 bar and is made up of large-diameter pipelines. The HTL acts as a transit network to and from other countries, as well as transporting gas to bulk consumers such as industry and power stations. The RTL is made up of branch pipes from the HTL, with a pressure of between 40 and 8 bar and usually small-diameter pipelines. The RTL is a distribution network that supplies directly to smaller industries and to the regional network operators, which in turn supply the small consumer market. In this study, the hydrogen network is assessed as equivalent to the HTL; no research has been carried out into potential bottlenecks in a future hydrogen RTL.

After determining the distribution of hydrogen supply and demand across the country by allocating it to specific areas (see section 5.4 on the regionalisation of supply and demand), this was projected at an entry or exit point on the hydrogen transport network. Figure 21: Projection of regionalised hydrogen supply and demand at the network points (also referred to as entry and exit points) in the hydrogen network shows what this means. The yellow lines connect each area to the hydrogen transport network. This study did not examine whether measures are necessary to connect this regionalised supply and/or demand to the entry and exit points. One example of a measure is a connecting pipeline from the hydrogen transport network to these locations. The purpose of the research (to determine the impact of variation in offshore wind energy landing zones) justifies this simplification.

Figure 21: Projection of regionalised hydrogen supply and demand at the network points (also referred to as entry and exit points) in the hydrogen network

Chapter 3.4 describes the assumed hydrogen network used in the analyses in this study. The four scenarios (and two variations thereon) result in supply and demand forecasts in the form of 8760-hour time series at a large number of entry and exit points in the hydrogen network. In combination with the need for flexibility, supply and demand is balanced by means of an import or export volume and through storage.

Connections to natural gas storage facilities in the current natural gas network have been designed to meet today's high demand for natural gas storage. However, it is not sufficiently clear whether empty natural gas fields in the Dutch subsurface are suitable for the storage of hydrogen. This study therefore assumes that hydrogen will be stored in salt caverns, of which there are a limited number in the Netherlands at present (in Zuidwending near Veendam). For the purpose of this study, it is therefore assumed a large proportion (two thirds) of hydrogen storage in 2040 will be in Zuidwending and the remaining proportion (one third) in the German town of Epe, just across the border at Enschede. If hydrogen storage becomes available at other locations, the impact on the network will change.

Entry and exit combinations that place a heavy burden on the network have been assessed on the basis of capacity implications for those networks according to the method described in the II3050 report. The analysis deviates from this methodology on the following points:

- Transport models have been used to assess network capacity. The analysis is based on an expanded hydrogen network compared to the network in 2030 (the look ahead to 2035).
- Supply and demand are determined at neighbourhood level using the ETM. Neighbourhoods are linked to the hydrogen network by means of the shortest geographical distance (as the crow flies) to a network point in the hydrogen network. The anticipated hydrogen network entry and exit points in 2030 have been taken as a starting point. The assumption is that both entry and exit flows can be accommodated at each entry and exit point.
- The maximum and minimum monthly entry and exit capacity has then been determined for each entry and exit point and used as a basis to create ‘snapshots’ for the transport network.
- The effects of the ‘snapshots’ have then been calculated. Where a ‘snapshot’ results in a bottleneck, this bottleneck is resolved through the use of compression (at existing compressor locations) and/or by assuming a pipeline that runs parallel to an existing route. It has not been investigated whether an additional pipeline would potentially be available from the existing natural gas network.
- The hydrogen transport network has been assessed using pressure drop calculations with a maximum pressure of 50 bar(a) and a minimum pressure of 30 bar(a). This pressure is lower than the pressure in the current HTL natural gas grid. Research has shown that existing natural gas transmission pipelines can be safely reused to transport hydrogen at a maximum pressure of 50 bar(a) (Strategy&, 2021). It is currently being examined whether maximum pressure can be raised to 65 bar(a). This can increase the capacity of the pipelines.
- The impact of variations in landing zones on the measures required to resolve any bottlenecks was then examined for each scenario.

5.7 Optimisation of electrolysis capacity

The results of the flexibility analysis served as input for the electrolysis capacity optimisation calculations. A linear optimisation model was developed for this purpose, in Excel, based on an hourly and annual energy balance. Demand for electricity and hydrogen must be balanced with supply on an hourly basis; the costs were calculated based on the annual totals. The calculation steps, assumptions, and limitations of the optimisation model are set out here.

The model is based on the time series for demand and supply of electricity and hydrogen. These series follow from the flexibility analysis described in sections 5.4 and 5.5, which aims to balance supply and demand. A number of tools are used to achieve this, namely batteries, gas-fired power plants, hydrogen power plants, curtailment, and electrolysis[35]. The flexibility analysis did not include any economic optimisation of the relationship between these tools. The electrolysis optimisation model has therefore used the resulting time series for supply and demand, but has re-determined the use of electrolysis and curtailment with the aim of minimising annual system costs.

The time series for supply and demand used are set out in Table 3. The table shows fixed and variable curtailment. Fixed curtailment comes from the flexibility analysis, in which a fixed limit is assumed above which a small proportion of offshore wind is curtailed. This limit is set so that 5% of the offshore wind electricity produced is curtailed, to ensure the capacity of the offshore grid is not designed on the basis of production peaks that only occur a few hours each year. Variable curtailment comes from the optimisation model, in which the algorithm achieves an economically driven balance between the use (and installation) of electrolysis capacity and the curtailment of offshore wind production in the event of a surplus of renewable production. It should be noted that no time series for hydrogen supply have been taken from the flexibility analysis, as electrolysis use was re-calculated at this step of the analysis. Hydrogen demand has been met in several ways, including blue and grey hydrogen and import of green hydrogen. This energy balance has been assessed on an annual basis. Please note, as a result of this annual assessment, the costs associated with hydrogen storage and flexible supply of hydrogen from storage facilities have not been included in the economic analysis.

Table 3: Time series from supply and demand and flexibility analysis as input for optimisation of electrolysis capacity

Electricity demand	**Electricity supply**
National demand (cumulative over all sectors)	Offshore wind
Fixed curtailment	Onshore renwables (wind and solar-pv)
Export	Import
Battery charge	Battery discharge
Battery losses	CHP
	Gas fired power plants
Hydrogen demand	**Hydrogen supply**
Hydrogen fired power plants	Grey hydrogen
Industry	Blue hydrogen
Urban environment	Domestic green hydrogen
Transport	Import green hydrogen
Export	
Fuels for international transport	

Whereas the electricity balance is resolved on an hourly basis, the hydrogen balance is considered on an annual basis. In specific terms, this means there are no hourly values for hydrogen supply and demand, but annual totals have been used for the calculation. The use of hydrogen in gas-fired power stations

[35] Please note: demand-side response has been applied in this study by means of adjusting the electricity demand profile

(one of the time series from the flexibility analysis) has therefore been aggregated. This demand for hydrogen in the electricity sector, plus the hydrogen demand in other sectors (an input parameter, based on the scenario), has been met with blue and grey hydrogen, and hydrogen from onshore electrolysis. This last item is the sum of the resulting time series from the optimisation. Import of green hydrogen from other countries at import costs was last on the list for the annual hydrogen balance (see Break-out 3 for the bottom-up calculation of the import price). The algorithm has therefore achieved a cost-effective balance between installing and deploying electrolysis, importing green hydrogen at import costs, and curtailing electricity surpluses. The supply from the above time series is sufficient to meet demand for electricity in any hour (outcome of the flexibility analysis). However, surpluses of renewable electricity still occur. These surpluses could be used for electrolysis, limited by the optimised electrolysis capacity, or will be eliminated through curtailment.

Figure 22 is a schematic depiction of the optimisation model. The supply and demand time series from the flexibility analysis have been adopted as input and used as a basis to calculate the energy balance for electricity and hydrogen on an hourly and annual basis respectively. In other words, the electricity balance is resolved on an hourly basis, on the precondition that total hydrogen production by electrolysis is equal to annual demand minus the supply of blue and grey hydrogen, and hydrogen imports. The annual system costs, including hydrogen import, follow from the energy balance. The algorithm[36] then iterates the electrolysis capacity until it converges to a global optimum of annual system costs. The result is the economically optimal electrolysis capacity, provided the energy balance is maintained.

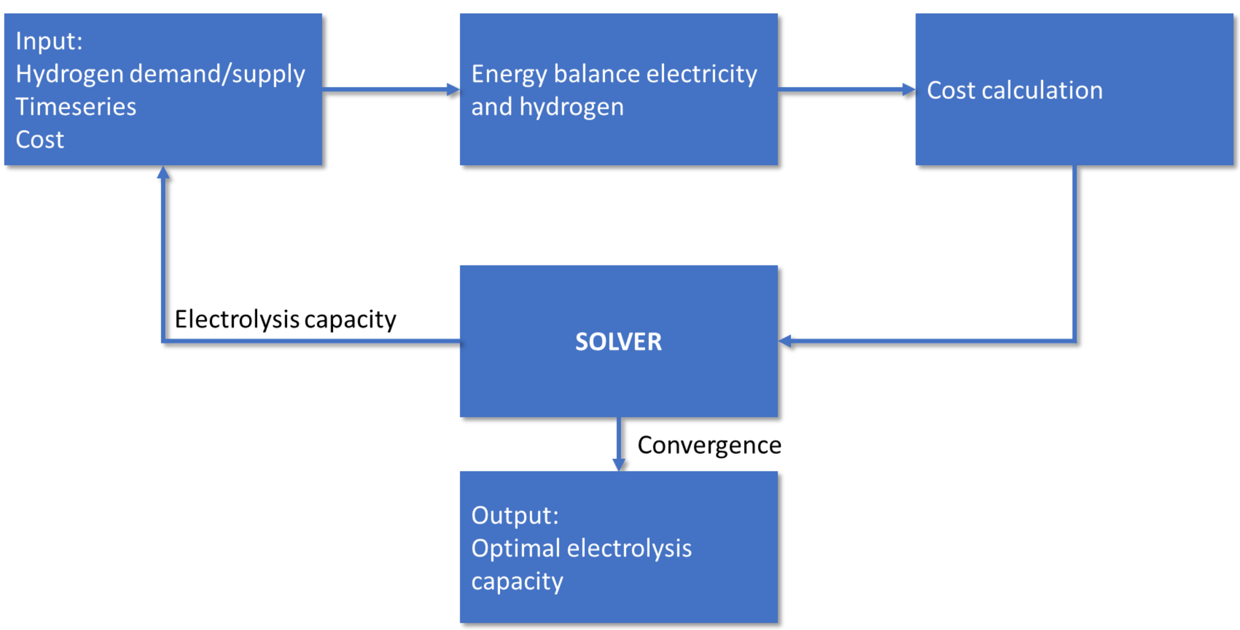


Figure 22: Conceptual representation of the electrolysis optimisation model

[36] The algorithm is based on a linear solver, a built-in function of Excel.

Kader 3: bottom-up calculation hydrogen import price

The hydrogen import price is based on four cost parameters: (1) CAPEX of electrolysis, (2) OPEX of electrolysis, (3) cost of electricity use, and (4) cost of transport.

$$Import\ cost\ \left[\frac{EUR}{kg}\right] = \frac{CAPEX + OPEX + Electricity}{Annual\ production} + Transport$$

1. CAPEX of electrolysis is 300 €/kW installed capacity. The weighted average cost of capital (WACC) of 8% and a 25-year lifetime results in an annual CAPEX of 28.10 €/kW/year.
2. OPEX of electrolysis is assumed to be 9 €/kW/year in 2040.
3. LCOE of solar-PV in southern Europe in 2040 is expected to be 12.16 €/MWh, the number full load hours is estimated at 1715 per year.
4. Cost of transport from southern Europe to the Netherlands is assumed to be 0.34 €/kg in case of a pan-European hydrogen backbone (European Hydrogen Backbone, 2020). Other modes of transport (shipping) are estimated to be 0.70 €/kg more expensive.

The efficiency of electrolysis is 72%, the lower heating value is 33.30 kWh/kg. The equation for the import cost of hydrogen becomes:

$$Import\ cost\ \left[\frac{EUR}{kg}\right] = \frac{\left(28.1\frac{€}{kW} + 9\frac{€}{kW} + 1715\ h * \frac{12.16\frac{€}{MWh}}{1000}\right)}{\frac{0.72 * 1715\ h}{33.30\frac{kWh}{kg}}} + Transport$$

Based on the II3050 scenarios, we make a distinction between scenarios with access to a European hydrogen backbone and scenarios without. The resulting import costs of hydrogen are:

Scenario/variant	Import cost
European, International	1.9 €/kg
Regional, National	2.6 €/kg

5.8 Offshore infrastructure cost calculations

The infrastructure cost calculations are based on the configuration types described in chapter 3. For the various components, such as offshore wind, electrolysers, and pipelines, both investment costs (CAPEX) and operating (OPEX) expenses have been included in the cost totals. To ensure a fair comparison between different configurations, the investment costs have been normalised to annual costs using a capital recovery factor (CRF). The CRF was determined on the basis of the lifespan of the various cost components and the associated capital costs of such a project (weighted average cost of capital, WACC).

The cost calculations and assumptions in relation to offshore infrastructure are divided into two parts: landing electricity, and landing in the form of hydrogen in the case of offshore hydrogen production. A summary of the cost parameters used is presented in Table 20: Cost assumptions, in Appendix A.

5.8.1 Landing as electricity

The offshore wind farms in the various search areas are connected to the mainland by transmission cables. This takes into account the distance between the wind farms and the landing zones and the capacity of the wind farms in question.

Over long distances, electricity transmission through direct current is more cost efficient than alternating current. As more and more new wind farms are located at greater distances from the coast, there has been an upsurge in the use of High Voltage Direct Current (HVDC) cables. Conversion from alternating current to direct current is therefore necessary in order to transmit the electricity generated to land, as well as transformation to high voltage (525 kV). Conversion is then once again required on land in order to feed the electricity into the national (380 kV) high voltage grid. In short, the electrical infrastructure is divided into an offshore HVDC station, an offshore platform, one or more export cables, and an onshore HVDC station for each wind farm connected to the land.

5.8.2 Offshore hydrogen production and landing using pipelines

Pipelines and compression

Where hydrogen is produced offshore, offshore hydrogen pipelines are an effective option for the transport of hydrogen to landing zones.

Offshore pipelines are often used to transport natural gas. No offshore hydrogen pipelines have yet been constructed and the available literature on new offshore pipelines for hydrogen transport is currently limited. Based on the literature listed below (Table 4) and the study previously carried out for the European Hydrogen Backbone study, offshore infrastructure costs for hydrogen transport are expected to be in the region of €55–75 k/inch/km (European Hydrogen Backbone, 2021). This assumes the costs of new hydrogen pipelines will not exceed the costs of constructing and reusing natural gas pipelines. It is realistic that cost reductions will be possible when new pipelines are laid for hydrogen. For comparison, the table also shows the costs of CO_2 pipelines for CCS. For the modelling, a cost level of €65k/inch/km has been assumed for pipelines.

Table 4: Various CAPEX values for onshore and offshore pipelines

CAPEX range (k€/inch/km)	Onshore/offshore	Source:
55–75	Onshore	European Hydrogen Backbone study (European Hydrogen Backbone, 2021)
40–57	Offshore	North Sea Energy: A vision on hydrogen potential from the North Sea (North Sea Energy, 2020)
44–50	Offshore	ORE Catapult: Offshore Wind and Hydrogen, Solving the Integration Challenge (Catapult, 2020)
52–85	Offshore	The costs of CO_2 transport: Post-demonstration CCS in the EU (Global CCS Institute, 2011)

CAPEX range (k€/inch/km)	Onshore/offshore	Source:
65	Offshore	Modelling assumption.

Based on interviews, the expectation is that old natural gas pipelines can be reused for hydrogen with limited modifications in the future, for example in the case of valves in pipelines (see Break-out 2 in section 3.2). The costs associated with the reuse of pipelines are estimated to be 10–35% of those for new pipelines.

The modelling assumes the use of pipelines with three different diameters. The diameter of the pipeline determines the hydrogen transport capacity, as illustrated by the Table 5.

It should be noted that the cost estimate and capacity calculation are a simplified representation of reality. The capacity of a pipeline depends on several factors such as inlet and outlet pressure and length. The costs are partly dependent of the diameter.

Table 5: Capacity ranges for pipelines with different diameters at an input pressure of 120 bar, final pressure of 50 bar, and a pipeline length of 250 km, based on analysis by Gasunie

Pipeline diameter (inch)	Cpacity (GW_E electrolysis)	Capacity (ton/hour hydrogen)
20	5 GW	118
36	20 GW	428
48	45 GW	988

In terms of compression, there are two options: applying various compression steps over the length of a route, or bringing the hydrogen to a high pressure at the point of input to the pipeline. The addition of multiple offshore compression stations results in high costs, and we therefore assume that a single offshore compression step to high pressure is applied. Based on experience gained through the European Hydrogen Backbone study, we conclude it is sensible to apply compression after offshore hydrogen production. The input pressure for each pipeline diameter is calculated to be sufficient to compensate for the pressure drop over the pipelines over a longer distance. This assumes the hydrogen can be delivered to the landing point at a minimum pressure of 50 bar. The result is the hydrogen can be fed into the onshore hydrogen backbone without additional compression at the landing point. To do this, compressor capacity has been determined for various pipeline diameters using the formula in Appendix A. The compression costs are based on analyses from the European Hydrogen Backbone study and the North Sea Energy programme and have been normalised for this study at €3.4 million/MW.

Offshore conversion of electricity to hydrogen

Offshore electrolysis can be centralised or integrated into wind turbines, with the centralised option expected to be developed earlier, based on the market consultation in this project. The following options have been included in this study in order to calculate costs for offshore infrastructure, taking into account the various components described in section 3.2:

1. Centralised on an energy island

Where this option is chosen, all costs are included for an artificial island. The assumption made here is that it is possible to connect multiple wind farms to a single artificial island. The costs of the island are based on data from the Cost Benefit Analysis (CBA) for the Danish Energy Island (COWI, 2021) and the IJVERTECH study (Topsector Energie, 2019). The latter study contains a surface area calculation for a 2 GW P2G island, including auxiliary equipment, supporting infrastructure, and building. Table 6 presents the elements of a P2G island and the required surface area. A distinction is made between elements that scale with electrolysis capacity and elements for which the required surface area remains consistent. It is assumed that a 2 GW P2G island requires a surface area of 24 hectares, and a 12 GW P2G island, 80 hectares.

Table 6: Required surface area in hectares for a 2 GW P2G island, based on IJVERTECH

Component	Area (ha)	Scales with capacity?
Electrolyser	8.8	Yes
Control room	0.04	Yes
Workshop P2G	0.15	Yes
Accommodation	0.18	Yes
Local infrastructure	1.83	Yes
Helicopter platform	0.675	No
Quay	1.8	No
Pipeline (exit) and cable (entry)	2.4	No
Coastguard	2.4	No
Basin	6	No
Total:	24.28	-

The costs of an energy island are dependent on local water depth and offshore conditions. The wide variation in these costs is also clear from the difference in cost per square metre in the two studies consulted. The calculation for the Danish energy island is based on €3187/m^2, while the IJVERTECH study features a range of €1422–2483/m^2.

Table 7: Costs for a large-scale (>10 GWe) P2G island

Island cost (M€/GW$_{elektrolyse}$)	**Source**
210.6	Guidehouse analysis based on *Cost benefit analyse ogklimaaftryk af energiøer i Nordsøen og Østersøen* (COWI, 2021) and *IJV*ERTECH (Topsector Energie, 2019).

To enable access by means of an energy island, intermediary High Voltage Alternating Current (HVAC) platforms and cables have also been included in the cost to connect wind farm zones too far away (more than 30 kilometres) to be connected with inter-array cables to the island. A 36” hydrogen pipeline is assumed for the 12 GW situation.

2. Centralised on one or more connected P2G platforms

Where this option is chosen, all costs are included for one or more offshore platforms. The need for multiple platforms is determined by the maximum capacity of a single platform, whereby the maximum capacity per platform is approximately 500 MW. Where multiple platforms are included in the calculation, the costs of the platform, electrolysis, and compression are multiplied by the number of platforms. In calculating the pipeline costs, account is taken of the fact that multiple platforms can be connected to a single pipeline to the coast, which means only the additional pipelines between platforms need to be included.

3. Integrated into wind turbines

A final option is to integrate hydrogen production into wind turbines. There is still a great deal of uncertainty regarding the costs associated with this, but it could lead to cost savings. Measures may include omitting various electrical components in the wind turbine and electrolyser, resulting in a reduction in electrical losses and CAPEX. Switching transmission infrastructure would also have financial implications, enabling wind turbine designers to search for new optimal solutions and potentially to produce more energy per km^2.

Appendix A contains a table that sets out the key cost assumptions.

6 Results

This chapter describes the results of the modelling. Various landing configurations for offshore wind energy were used during the modelling and the financial implications were assessed for the different scenarios and variants. The main results are described in section 6.1, with a focus on the results that are not scenario-specific, but instead reflect a general trend. Section 6.2 presents the system impact of the solutions using a number of cross-sections of the results. The scenario-specific results are described in section 6.3 and the '*international additional offshore wind*' and '*national additional electrification*' variants are described in section 6.1.1.2. Finally, section 6.4 contains an analysis of the key sensitivities within the modelling.

6.1 Main results

A number of solutions have been explored in order to analyse the interaction between offshore wind energy, electrolysis, and the energy system (both electricity and gas). Two different offshore wind capacities were assumed: 31 GW and 38.5 GW (see also section 3.1).

During this process, four solutions were explored for landing the offshore wind energy generated:

1. All-electric landing with electrolysis only in the event of electricity surpluses
2. All-electric landing with coupled[37] onshore electrolysis
3. All-electric landing with onshore electrolysis to prevent congestion
4. Combined electricity landing and coupled offshore electrolysis

Each of these options had cross-scenario results (for both the electricity and hydrogen grids), which are described below for each solution. The difference between the solutions lies in the application of the current policy framework for congestion management (solution 1) and the amendment of this framework to enable coupling with electrolysers as a long-term solution to prevent congestion (solutions 2, 3, and 4). Identifying the solutions was a dynamic process between all parties in the model working group, whereby insight gained during the modelling of a solution was used to search for the next solution. The following sections describe the main results for each solution, and how these results were used in the next solution.

It should be noted that electrolysis serves a system function in these analyses (integration of energy from offshore wind and reducing grid congestion). In reality, an electrolysis operator will aim for a profitable business case, in which behaviour will be driven by the market (on which the policy framework naturally has an influence).

[37] 'Coupled onshore electrolysis' means that an onshore electrolyser is directly coupled with some or all of the capacity of a specific offshore wind farm, whereby the electrolyser load adapts to the profile of the wind energy generated by that specific wind farm. This is also sometimes referred to as 'dedicated' electrolysis, i.e. electrolysis which is dedicated to convert offshore wind electricity to hydrogen.

6.1.1 All-electric offshore infrastructure, electrolysis as a flexibility measure to alleviate electricity surpluses

The first solution explored is in line with the modern approach to connecting offshore wind farms: all-electric (radial) landing, spread across a number of landing zones. The aim of this solution is to identify where the largest bottlenecks are in the electricity grid and whether they can be resolved with different electricity landing configurations. This solution also provides insight for future iterations in terms of the limits and interactions that need to be taken into account within the electricity grid. These calculations assume electrolysis near to the landing zones in the event of surplus renewable energy production (see chapter 4.3).

6.1.1.1 Majority of offshore wind landfall in Maasvlakte

The left of Figure 23 shows the first all-electric landing configuration for a total of 38.5 GW of installed offshore wind capacity, which results in 35.6 GW of landed capacity after losses. The rationale behind this configuration is the large amount of industry at Maasvlakte, in Zeeland and around Beverwijk. The configuration involves feeding more than 14 GW of electrons into the Maasvlakte electricity grid. The 31 GW landing configuration is similar.

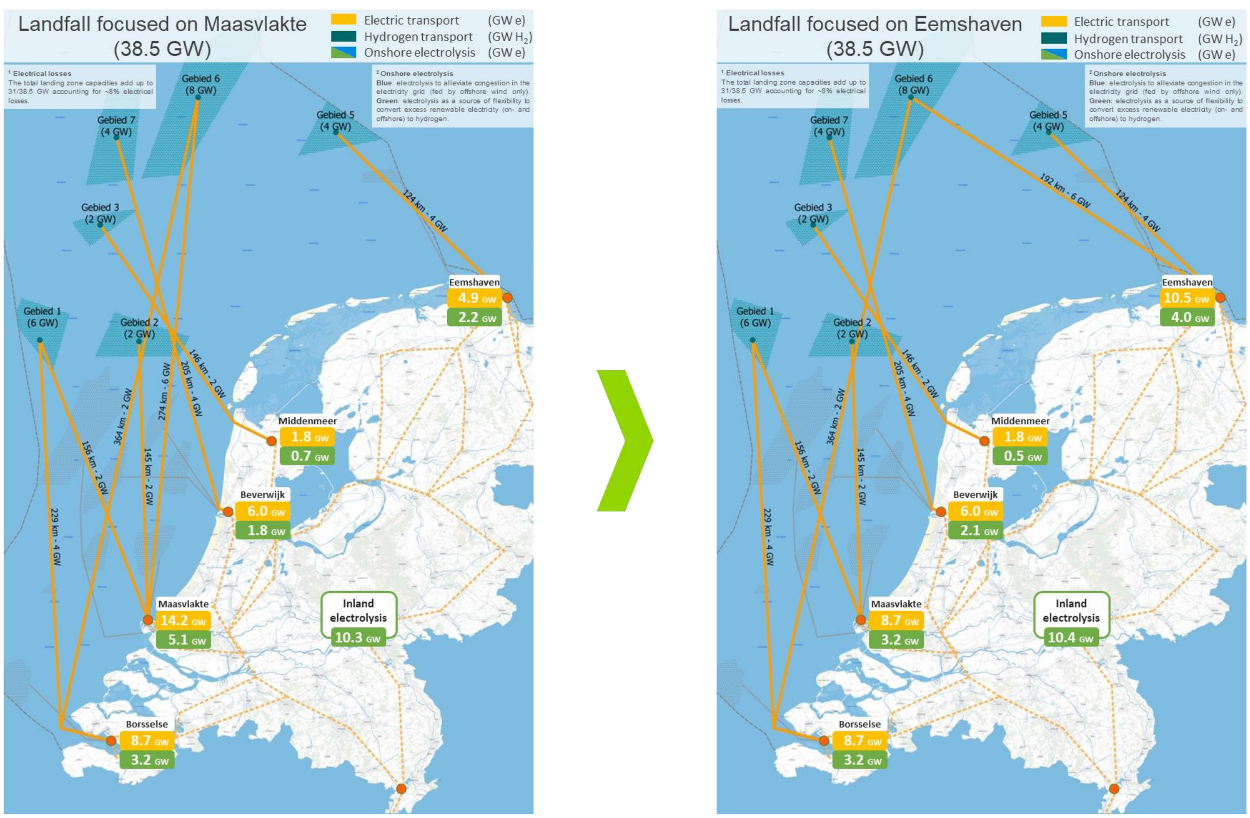


Figure 23: 38.5 GW configurations for the all electric solution with electrolysis only in the event of electricity surpluses. The landed capacities stated are after losses.

The main conclusion for the all-electric landing configuration, in which a large proportion of the power is landed at Maasvlakte, is that the electricity grid becomes overloaded at several points. See also the left half of Figure 24. The electricity grid analysis reveals the following bottlenecks:

- **Maasvlakte ring**
  This configuration severely overloads the electricity ring around Maasvlakte. The congestion is so severe (an operational solution is expected to cost around €250m per year) that grid reinforcements would certainly be required, a situation that could be avoided with a different landing option for offshore wind energy. Another outcome of the analysis is that the maximum capacity input, without using coupled electrolysis, is around 7.5 GW for Maasvlakte.

- **Tilburg–Eindhoven–Maasbracht route**
  The expected high industrial demand around the Maasbracht region and the limited supply potential from the coast (Maasvlakte/Borssele via Eindhoven–Maasbracht route or from the North via Hengelo) means the route between Tilburg and Maasbracht shows significant overload. The recently published IP2022 investment plan already provides for an expansion of the Eindhoven–Maasbracht connection, but not yet for the Eindhoven–Tilburg connection. In view of the high number of hours, an operational solution (by means of re-dispatch) is expensive for this connection (around €60m per year for the national scenario).

- **Diemen region**
  A total input of 7.8 GW of power from Beverwijk and Middenmeer moderately overloads the electricity grid around Diemen. The overload can be resolved operationally for reasonably high costs (around €40m per year for the national scenario). As a guideline, the analysis shows the total combined power input for Beverwijk and Middenmeer is around 6 GW. A second possibility to further relieve the burden on Diemen is by landing more power in Eemshaven, which can then be transported inland using the northern networks.

- **Zwolle–Hengelo route**
  This route is not directly affected by the specific landing configuration, however it does show a significant overload. Simplification of the interconnection modelling with other countries is expected to reduce the burden on this route in reality. If the overload is such that grid reinforcements nevertheless prove necessary, this can still be achieved in good time.

A significant part of the above congestion problem can be resolved by means of substantial curtailment of offshore wind energy, whereby the resulting energy losses will need to be compensated for by additional import (of electricity of hydrogen) from other countries.

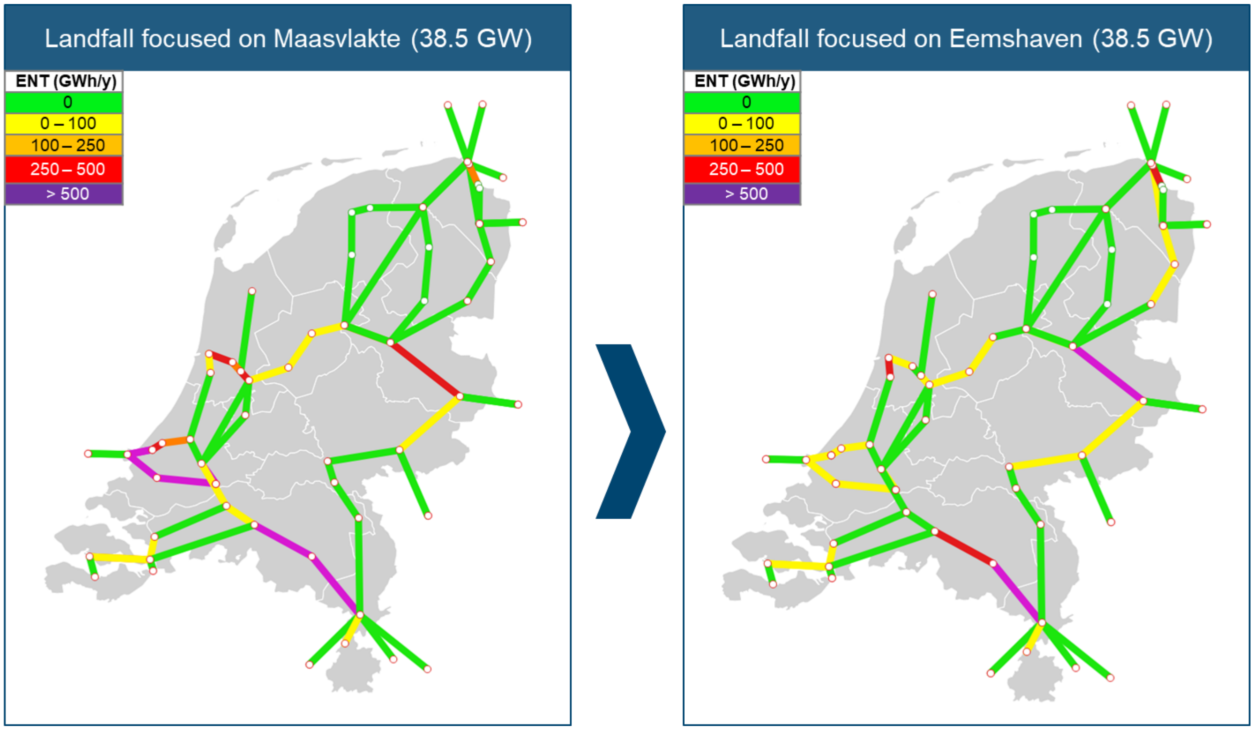


Figure 24: Electricity grid congestion for the all-electric solution with electrolysis only in the event of surpluses

The congestion issues described above have led to the conclusion that all-electric landing in the direction of Maasvlakte requires substantial additional expansion of the envisaged high-voltage grid. The analysis also reveals that northern Netherlands still offers scope for additional power input due to plans for capacity expansion in the run-up to 2035 from Eemshaven to Ens and an additional connection between Diemen and Ens. The above findings also apply, in a general sense, to the 31 GW configuration, in which the problem is of a smaller scale. The findings from the all-electric landing configuration in the direction of Maasvlakte have been incorporated into a second variant for all-electric landing without congestion measures.

6.1.1.2 Landing in the direction of Eemshaven

As described in the previous section, the national electricity grid in the northern Netherlands offers additional capacity for the input of electricity from offshore wind[38]. The first indications are that around 10 GW of electricity can be fed in at Eemshaven. This new landing configuration is shown on the right of Figure 24. In this configuration, landing in Maasvlakte is reduced by approximately 5.5 GW, while landing in Eemshaven is increased by the same amount of power. Landed power remains unchanged for Borssele, Beverwijk, and Middenmeer. As the total power input from offshore wind is greater than the sum of the limits for each landing point, it is impossible to remain within the limit at each location, as

[38] Please note that the national electricity grid is not necessarily the limiting factor for landing in northern Netherlands; spatial and social aspects (including offshore) also play an important role. If capacity at Eemshaven is limited for spatial/social reasons, another solution must be found to the congestion problems.

shown by the analysis of landing in the direction of Maasvlakte. However, efforts have been made to remain as close as possible to the limit in each area to achieve the best possible distribution. The main results of the electricity grid analysis for this configuration are shown on the right half of Figure 24.

The main findings with regard to landing in the direction of Maasvlakte are as follows:

- **Eemshaven region**
  Landing of around 5.5 GW of additional power in Eemshaven does not result in a significant overload in this region that cannot be resolved operationally. A short route (approx. 2 km) between Eemshaven and Eemshaven Oudeschip shows a severe overload. However, TenneT has indicated this problem was already identified in the latest investment plan (IP2022) and is being resolved with specific network expansions.

- **Maasvlakte ring**
  This configuration places a significantly lower burden on the electricity ring around Maasvlakte, and the overload that still occurs according to the modelling can be resolved operationally.

- **Tilburg–Eindhoven–Maasbracht route**
  Demand for electricity around the Maasbracht region remains the same, and the possibility of feeding in power via Hengelo is limited. As a result, the route between Tilburg and Maasbracht remains overloaded, although to a lesser degree thanks to a better distribution of the power input. This reduction in overload lowers operational costs for the Eindhoven–Tilburg route to around €30m per year. The Eindhoven–Maasbracht route remains severely overloaded, but as previously stated, the latest investment plan (IP2022) already defines a solution to this in the study phase.

- **Diemen region**
  The overload is reduced for the Diemen region, as a greater part of the inland is supplied with electricity from the north. There is still a reasonably severe bottleneck between Beverwijk and Vijfhuizen, however the conductors for this connection can still be upgraded to 4 kA, which would all but resolve the bottleneck.

- **Zwolle–Hengelo route**
  The input of additional power in the north of the Netherlands means additional power will be transported from the north to the south. Part of this transport takes place via the route between Zwolle and Hengelo, increasing the overload on this route. Simplification of the interconnection modelling with other countries is expected to reduce the burden on this route in reality. If the overload is such that grid reinforcements nevertheless prove necessary, this can still be achieved in good time.

The above analysis shows that shifting approximately 5.5 GW of additional electrical power from Maasvlakte to Eemshaven resolves a substantial part of the problem. Whereas much of the overload on connections can probably be resolved operationally, it is interesting to define the role that electrolysis (both onshore and offshore) can play in resolving the remaining congestion problems affecting the onshore electricity grid. Table 8 shows the impact for the main connections on the amount of ENT in both the National and International scenarios.

Table 8: ENT in the National (38.5 GW) and International (31 GW) scenarios for the main connections for solutions with landing in the direction of Maasvlakte and Eemshaven.

		Energy Not Transported (GWh)	
	Connection	**Landing in the direction of Maasvlakte**	**Landing in the direction of Eemshaven**
National	Amsterdam - Diemen	445	5
	Borssele - Rilland	103	100
	Eindhoven - Maasbracht	2414	1139
	Hengelo - Zwolle	269	570
	Maasvlakte - Simonshaven	2545	59
	Robbenplaat - Weiwerd	147	474
	Tilburg - Eindhoven	572	286
International	Amsterdam - Diemen	35	2
	Borssele - Rilland	1	1
	Eindhoven - Maasbracht	1206	636
	Hengelo - Zwolle	154	206
	Maasvlakte - Simonshaven	2102	315
	Robbenplaat - Weiwerd	1889	2232
	Tilburg - Eindhoven	179	138

For the scenarios with 31 GW of offshore wind, the general conclusion is that ‘smart’ landing – in other words allocating offshore wind capacity to the connections with the highest available capacity (within the limitations of timelines and capabilities) – makes it possible to land the offshore wind capacity with the planned grid reinforcements (the solutions for overloaded routes in the 38.5 GW scenario also apply to the 31 GW scenarios). See Figure 25 for the results of the International scenario grid analysis (31 GW). It should be noted here that in this scenario, an additional bottleneck occurs between Maasvlakte and Simonshaven (this connection turns red). Pressure could be relieved on this bottleneck by directly connecting part of the offshore wind energy to the high-voltage substation in Simonshaven.

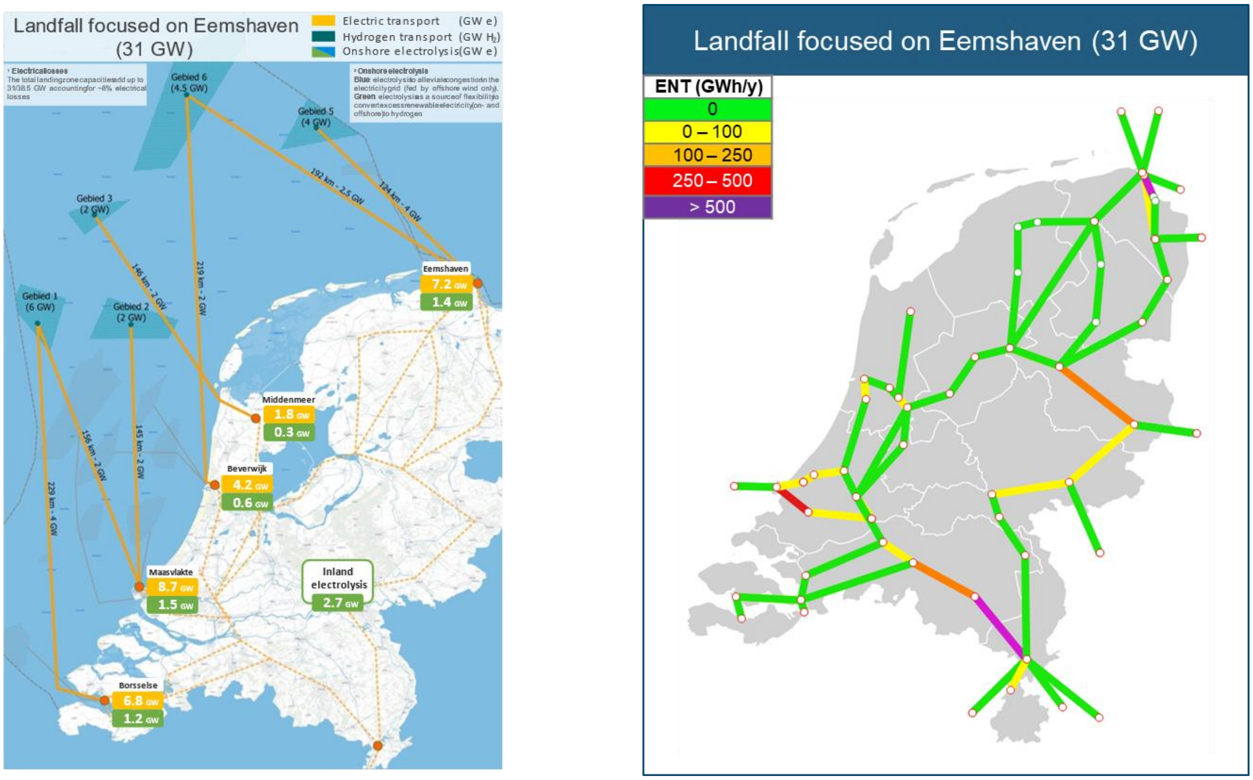
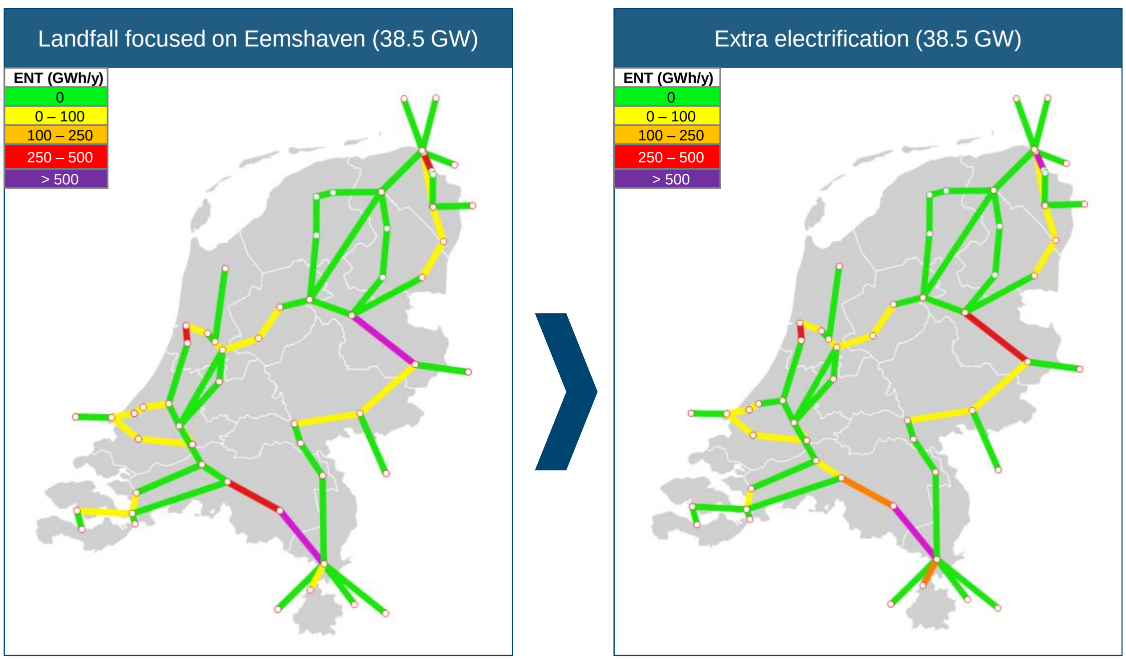


Figure 25: Electricity grid configuration and congestion in the International scenario.

Break-out 4: extra electrification in the National scenario

The effect of extra electrification (with respect to the electrification already foreseen in the scenario) is assessed within the context of this study. A larger share of the offshore wind energy can be used directly at the landfall due to this extra electrification, as this is where large, industrial demand centres are located. It is expected that this will result in a lower load on the electricity grid, and a higher direct use of electricity.

The figure below indicates that extra electrification indeed results in a light alleviation of the electricity grid, especially for inland connections. The total reduction is lower than expected, since a large share of the additional electrical demand is allocated to Chemelot. This results in high loads on connections within Noord-Brabant. Extra electrification of industry in coastal areas does result in a significant load reduction of the high-voltage network. Note that there remains uncertainty whether extra electrification is achievable within this timeframe, and whether regular grid reinforcements are still necessary beyond 2040.

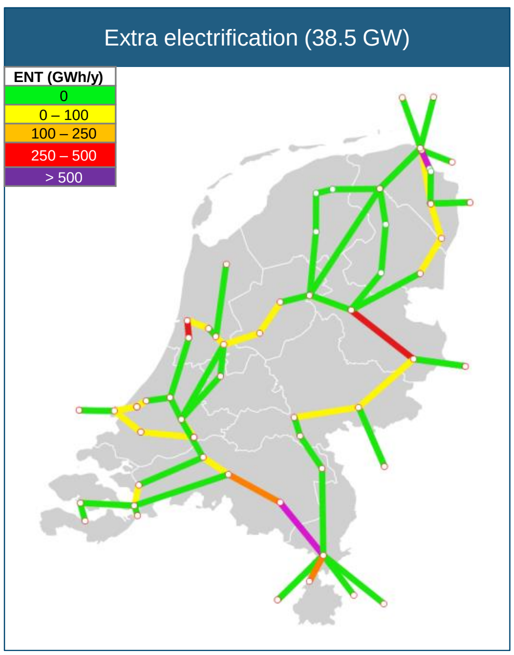


Break-out 5: extra electrification combined with inland landfall

A deeper inland landfall is a possible solution to realise full-electric offshore infrastructure without electrolysis for congestion measures. The effect of 2 GW offshore wind landing via HVDC in Graetheide (high voltage station read Chemelot) instead of Maasvlakte is assessed in this study. With this solution, the demand in the Chemelot region can be served by offshore wind electricity directly. It is expected that this solution should reduce the congestion on the connections between Tilburg and Maasbracht significantly.

De results of the congestion analysis show that a deep inland landfall reduces the congestion between Tilburg and Eindhoven to a level that it can be resolved with operational measures. The connection between Beverwijk and Vijfhuizen sees higher loads, but these can still be resolved by upgrading the conductors to 4 kA.

A deep inland connection can help alleviate grid congestion. However, the costs and benefits of such an inland HVDC connection must be weighed carefully against the costs and benefits of regular grid reinforcements.



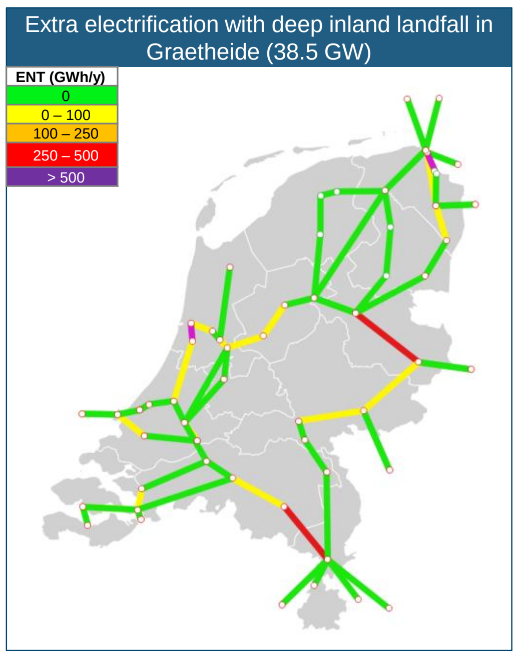


Table 9 shows the impact for the main connections on the amount of ENT in the National scenario from the break-outs above.

Table 9: ENT in the national (38.5 GW) scenario for the main connections for the variants with additional electrification.

		Energy Not Transported (GWh)		
	Connection	**Landfall focussed on Maasvlakte**	**Extra electrification**	**Extra electrificaation with deep inland landfall**
National	Amsterdam - Diemen	445	5	1
	Borssele - Rilland	103	79	80
	Eindhoven - Maasbracht	2414	985	452
	Hengelo - Zwolle	269	484	352
	Maasvlakte - Simonshaven	2545	75	19
	Robbenplaat - Weiwerd	147	3219	3194
	Tilburg - Eindhoven	572	218	38

6.1.1.3 Impact on the future hydrogen network

The analysis of the hydrogen network shows that regardless of how the landings for offshore wind are distributed, and the associated distribution of installed electrolysis capacity, the planned hydrogen network can be expanded to allow processing of the hydrogen flows to be fed in. This conclusion can be drawn for all solutions and scenarios, but is described here in more detail. The maximum expected congestion is caused by the required capacity of hydrogen power plants. In the event of major electricity shortages (almost zero production from sun and wind), these power plants require large quantities of hydrogen for a short period of time. This hydrogen is supplied from the storage facilities. The large hydrogen flows from storage facilities require a large amount of transport capacity during these relatively short peaks, which can be achieved with the aid of additional transmission pipelines and compression. Large hydrogen surpluses, which need to be stored in the storage facilities, also require expansions of the hydrogen network in the form of both compression and additional pipelines. However, the required compression capacity is much lower than needed for transmission from the storage facilities. When filling storage facilities, the gas will flow in a different direction through the network than when transmitting gas from storage facilities. This must be made possible by integrating the compressors into the hydrogen network. Such integrations, whereby compressors are able to compress in different directions by means of pipeline switching systems in which the same compressor can increase the pressure in different directions, already exist in the natural gas grid.

Existing natural gas pipelines can potentially be converted to hydrogen to meet this additional need for transport capacity in 2040. This approach is similar to the way in which the hydrogen backbone will be developed. However, it must be examined whether demand for natural gas has fallen sufficiently to convert existing pipelines so that transport security is still guaranteed. If this is possible, there will be no need to invest in the construction of new hydrogen pipelines. Hydrogen compression is also required at locations where compression of natural gas already takes place. The compressors themselves will need to be replaced, however, since natural gas compressors are not suitable for compression of hydrogen (Strategy&, 2021).

6.1.1.4 Comparison of offshore infrastructure costs and electrolysis capacity

For both configurations (large-scale landing at Maasvlakte and large-scale landing in Eemshaven), all offshore wind energy capacity will be landed after 2030, using radial 2 GW HVDC connections. The difference in cost of offshore infrastructure is therefore determined by total export cable length. The bar chart below compares the infrastructure costs of two configurations for the National scenario[39] (38.5 GW of offshore wind energy).

Landing at Eemshaven is slightly less expensive (2.3%) than landing at Maasvlakte. The difference in costs is largely explained by the difference in total HVDC cable length. For landing at Maasvlakte, total 2 GW HVDC cable length is 4393 km, whereas for landing in at Eemshaven, the total length is 4073 km. Although the difference in cable length is 7.3%, other infrastructure costs remain the same (HVDC converters and platforms) and the total cost difference between the two forms of landing is only 2.3%. An additional point to note is that north-to-south cables along the Dutch coast need to cross a large number of cables/pipelines, which may increase costs.

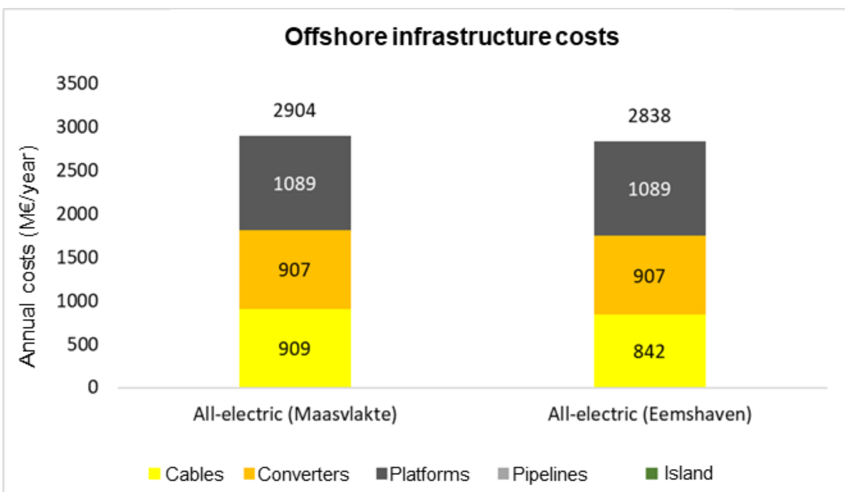


Figure 26: Difference between offshore infrastructure costs for large-scale landfall in Maasvlakte versus large-scale landfall in Eemshaven (National scenario, 38.5 GW of offshore wind capacity)

The result of the economic optimisation of electrolysis capacity is shown in Table 10. In this optimisation, the use of electrolysis as a flexibility tool (operation based on electricity surpluses) competes with the import of hydrogen and curtailment. Since a copper plate analysis shows the energy flows are the same in the two configurations, optimised electrolysis capacity and total hydrogen production is the same.

[39] The National scenario has been chosen for comparison as the impacts and cost effects are most prominent here. The same applies to 31 GW of offshore wind energy as to 38.5 GW offshore wind energy, although to a lesser extent.

Table 10: Comparison of electrolysis for large-scale landing in Maasvlakte versus large-scale landing in Eemshaven

	Landfall focused on Maasvlakte	Landfall focused on Eemshaven
Electrolysis capacity (GW_e)	23	23
Full-load hours (h)	3203	3203
Hydrogen production electrolysis (TWh_{H2})	53.6	53.6

6.1.2 All-electric offshore infrastructure with coupled onshore electrolysis

As the electricity grid analysis in section 6.1.1 showed for the configuration involving all-electric landing and electrolysis only in the event of electricity surpluses, this configuration causes certain routes in the Netherlands to become overloaded, resulting in a need for expensive operational measures. This led to the exploration of a new solution in which a number of GW in electrolysers at the landing zones are directly linked (coupled) to all or part of an offshore wind farm. The result is an artificial reduction in the landed electrical power from a specific wind farm by the total GW of installed electrolysis capacity. For example: a 4 GW wind farm with 1 GW of coupled installed electrolysis never needs to feed more than 3 GW of electrical power into the grid[40]. It should be noted that, in addition to the coupled electrolysis capacity, electrolysis also takes place for the processing remaining renewable electricity surpluses. This capacity is determined using the optimisation algorithm.

6.1.2.1 Landing configuration

Figure 27 shows the landing configurations for both 31 GW and 38.5 GW of offshore wind. The green blocks show installed electrolysis capacity, and the yellow blocks, maximum electricity supply from offshore wind at the landing zone. For the maximum amount of electricity that enters the grid, the power input must be reduced by the electrolysis capacity. For both the 31 GW and the 38.5 GW configuration, 1.2 GW of electrolysis capacity has been installed in Maasvlakte to limit the offshore wind energy fed into the electricity grid to the feed-in limit of around 7.5 GW. A similar concept is applied for the Middenmeer location. The difference is that there is 2.3 GW of electrolysis capacity in Middenmeer for the 31 GW offshore wind cases and 7.4 GW for the 38.5 GW offshore wind cases. It should be noted here that the amount of offshore wind energy fed into the electricity grid exceeds the limit for Beverwijk plus Middenmeer.

An adverse side effect of coupled onshore electrolysis is that at times when there is relatively little wind (offshore), the electrolysers still generate hydrogen, whereas this electricity could also have been used to meet the direct power demand. As a result, there is a greater need for G2P (hydrogen or methane) to meet power demand. G2P capacity remains almost the same, since it is driven by residual demand. Another downside of coupled electrolysis is that less renewable energy is used to meet electricity demand, and part of this renewable energy is lost in the process of converting electricity to hydrogen (and where demand for electricity exceeds supply, converting hydrogen to electricity). Finally, an

[40] Simplified representation; for the landing of electricity, transport losses from the wind farm to the landing point must still be taken into account, which means that a 4 GW wind farm will, in reality, land less than 4 GW of energy.

electrolyser directly coupled to an offshore wind farm cannot take advantage of peaks in solar PV production. However, this mode of operation is still a challenge in terms of applicable law, as it disrupts free market forces (by contemporary standards).

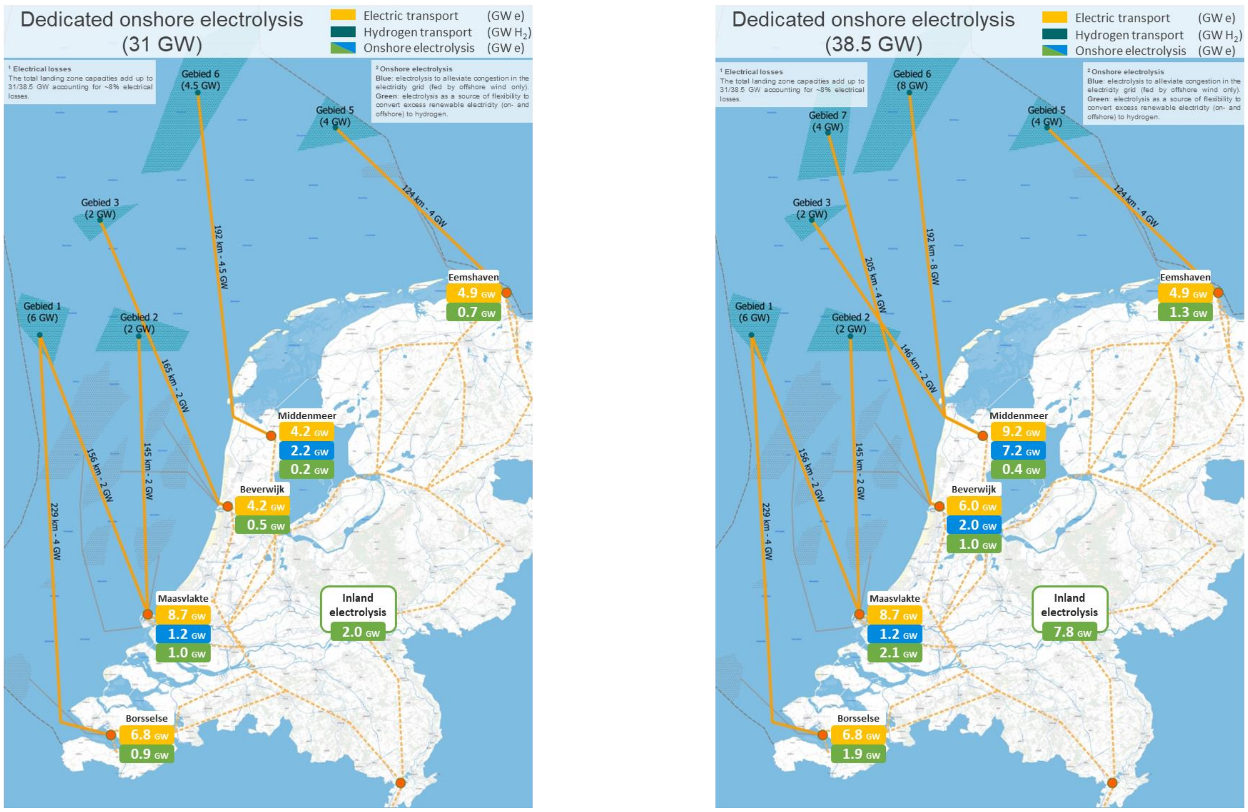


Figure 27: Configurations for all-electric offshore infrastructure with coupled/dedicated onshore electrolysis.

6.1.2.2 Electricity grid analysis

Power input for each landing point, after deducting the coupled electrolysis, results in similar capacity for the western Netherlands as in the all-electric (without coupled electrolysis) configuration at Eemshaven. As a result, the routes where congestion occurs are also broadly similar, as shown in Figure 28. This applies to both the 31 GW and 38.5 GW configurations. A clear difference is that the absence of large landed capacity in Eemshaven means there is little burden on the northern grids. In summary, the main bottlenecks for the solution with coupled electrolysis are:

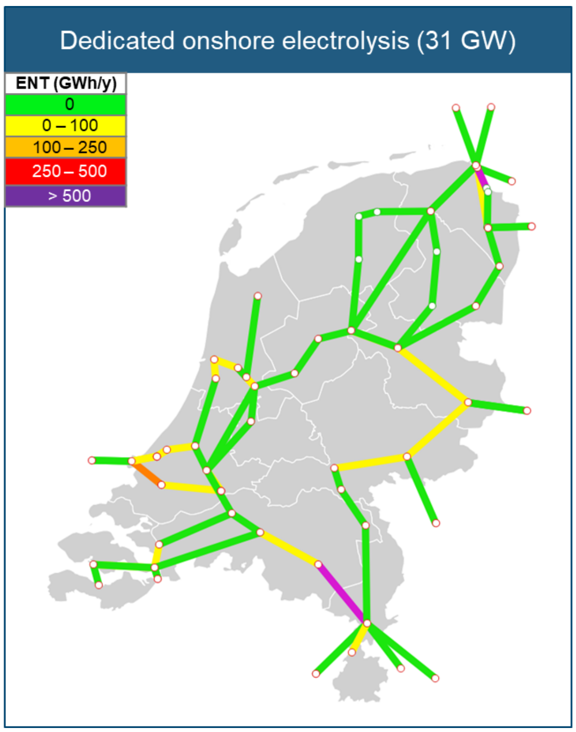
- **Maasvlakte ring**
  This configuration slightly overloads the electricity ring around Maasvlakte, with the expectation this can be resolved operationally.

- **Tilburg–Eindhoven–Maasbracht route**
  The Eindhoven–Maasbracht route is still overloaded. However, as previously stated, the most recently published investment plan (IP2022) provides a solution to this problem. The burden on

the Eindhoven–Tilburg connection is reduced in this configuration and can be resolved operationally.

- **Diemen region**
  There is a slight overload in the Diemen region, with the expectation this can be resolved operationally.

- **Zwolle–Hengelo route**
  The burden on this route is reduced compared to the previous solution, with the understanding that the remaining overload is probably overestimated due to simplification of the interconnection modelling with other countries.



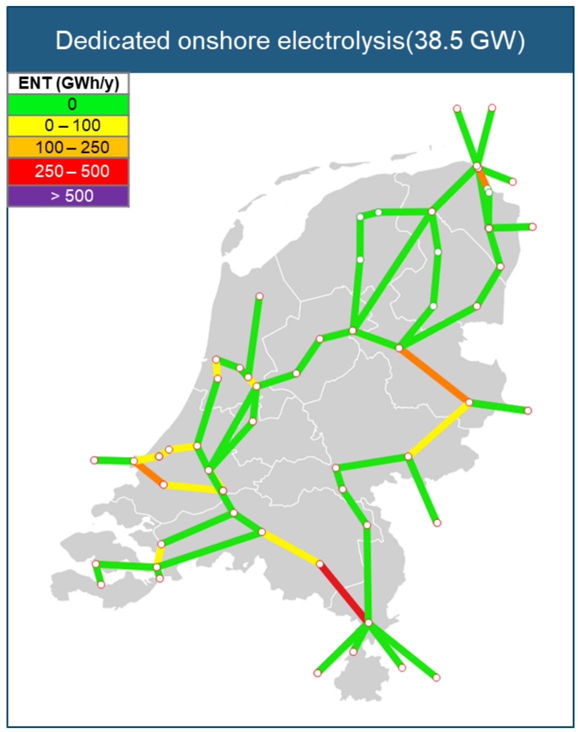


Figure 28: Electricity grid congestion for the solution all-electric offshore infrastructure with coupled onshore electrolysis

Table 11 shows the impact for the main connections on the amount of ENT in both the National and International scenarios.

Table 11: ENT in the national (38.5 GW) and international (31 GW) scenarios for the main connections for coupled electrolysis solutions compared to landing at Eemshaven.

		Energy Not Transported (GWh)	
	Connection	**Landfall focused on Eemshaven**	**Coupled onshore electrolysis**
National	Amsterdam - Diemen	5	5
	Borssele - Rilland	100	6
	Eindhoven - Maasbracht	1139	485
	Hengelo - Zwolle	570	134
	Maasvlakte - Simonshaven	59	115
	Robbenplaat - Weiwerd	474	144
	Tilburg - Eindhoven	286	67
International	Amsterdam - Diemen	2	8
	Borssele - Rilland	1	2
	Eindhoven - Maasbracht	636	542
	Hengelo - Zwolle	206	73
	Maasvlakte - Simonshaven	315	171
	Robbenplaat - Weiwerd	2232	1921
	Tilburg - Eindhoven	138	59

6.1.2.3 Impact on the future hydrogen network

The results of the gas network analysis are broadly consistent with the results for the first solution.

6.1.2.4 Offshore infrastructure costs and electrolysis capacity

In the case of coupled onshore electrolysis, there is a direct connection between an offshore wind farm and an onshore electrolysis facility. This means all the offshore wind energy is brought to the landing site as electricity. Infrastructure costs are therefore almost identical to the costs in the previous situation. Coupled electrolysis capacity partially replaces non-coupled electrolysis capacity which is activated in case of surplusses. Commercial agreements are expected to be drawn up for coupled electrolysis, in which a market price is agreed for the purchase of electricity from the wind farm, whether or not in combination with compensation financed by avoided congestion costs.

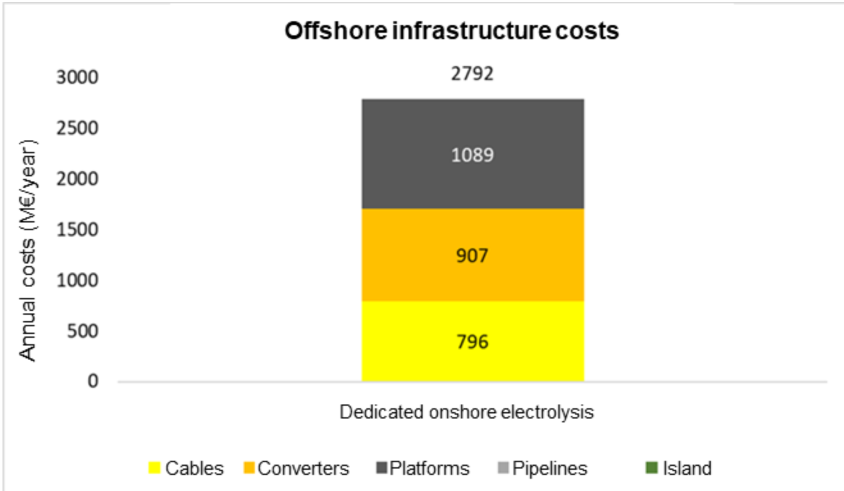


Figure 29: Offshore infrastructure costs for coupled onshore electrolysis (National scenario, 38.5 GW of offshore wind)

The table below shows the coupled electrolysis capacity and electrolysis for the purpose of system flexibility (or hydrogen production in the event of electricity surpluses). What is striking is that the full-load hours for coupled electrolysis are significantly higher. This is due to the fact that all electricity from the wind farm is converted to hydrogen. The coupled electrolysis capacity is calculated by deducting electricity and availability losses[41] from the offshore wind farm's capacity. This results in a higher number of full-load hours for the coupled electrolyser than for the wind farm[42].

Table 12: Overview of capacity and use of coupled electrolysis and electrolysis activated during surplus

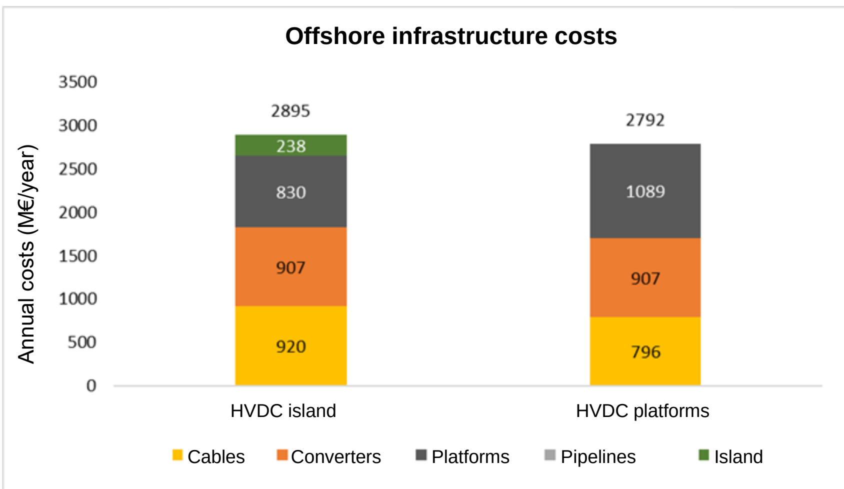
	Coupled	Activated during surplus
Electrolysis capacity (GW_e)	10.4	14.5
Full-load hours (h)	5115	2859
Hydrogen production electrolysis (TWh_{H2})	38.3	29.8

[41] 4.4% electricity losses and 96.5% availability. Please note that availability has been modelled as an average loss of 3.5% over the whole year.
[42] Sample calculation: Based on the assumed losses, for full conversion of electricity from a wind farm with a capacity of 1000 MW, a coupled electrolysis capacity of 923 MW is assumed.

Break-out 6: electric landfall with HVDC island

Previously discussed all-electric solutions make use of HVDC converters placed on offshore platforms. To gain insight in the cost of an HVDC island-based electric landfall, a cost analysis is performed as a sensitivity to the coupled onshore electrolysis solution. Instead of connecting search areas 6 and 7 to shore with HVDC platforms, a centralised island is placed in search area 6. The offshore wind areas are connected to the island with inter-array cables, or, for areas beyond 20 km of the island, with HVAC cables. The HVDC export cable to shore is assumed to be of same length as previously discussed solutions.

The figure below presents the cost differences between an island and platform-based solution. The HVDC converter costs are equal, cable costs increase due to the additional HVAC and inter-array cable length. Island costs partially replace platform (foundation and topside) costs. For this instance, the total cost of the island-based solution is higher than that of the platform-based solution, driven by the inter-array and HVAC cable lengths.



6.1.3 All-electric transmission to shore with onshore electrolysis to prevent congestion

For this solution, electrolysis is applied at the landing zones at times when the landing point's feed-in limit would be exceeded by offshore wind. For example: if 10 GW is landed at a site, and the limit is 6 GW, then 4 GW (minus losses) of electrolysis capacity is available. Only when the generated power from offshore wind exceeds the 6 GW for this landing point do the electrolysers come into operation. This approach differs from the previous solution: the electrolysers are only activated at times of high energy production from offshore wind. As a result, this electrolyser’s full-load hours will be lower than in the previous solution. At times when there is little wind, however, no energy will be converted into hydrogen where it can be used to meet direct electricity demand. This form of electrolysis could, in reality, be supplemented by solar PV surpluses, although such an approach has not been modelled for the purpose of analysing this solution[43]. It should be noted that, on top of the electrolysis capacity to prevent congestion, electrolysis also takes place for the processing of renewable electricity surpluses. This capacity is determined using the optimisation algorithm.

6.1.3.1 Landing configuration

Figure 30 shows the landing configurations for the solution involving electrolysis to prevent congestion for both the 31 GW and 38.5 GW scenario. Electrolysis is not used to prevent congestion at the Eemshaven and Borssele landing zones, as the feed-in limit is not exceeded at these sites. For the Maasvlakte landing point, both landed power and installed electrolysis capacity is the same in both cases. For the Beverwijk location, there is no installed electrolysis capacity for the 31 GW configuration, but there is 2 GW of capacity in the 38.5 GW configuration. The Middenmeer location sees the biggest differences, with 2.3 GW and 7.2 GW of installed electrolysis capacity for the 31 GW and 38.5 GW configurations respectively. Applying this method of electrolysis means that, from the perspective of the onshore electricity grid, the 31 GW and 38.5 GW variants are almost the same during peak offshore wind times.

[43] However, if the wrong choices are made, this could have major consequences for congestion on the high-voltage grid. Where, as in the National scenario, 7.2 GW in electrolysis capacity is assumed at Middenmeer that is also added to onshore solar energy, severe bottlenecks will occur at the connection to the Kop van Noord-Holland region (which is only intended to transport 2 GW of offshore wind energy).

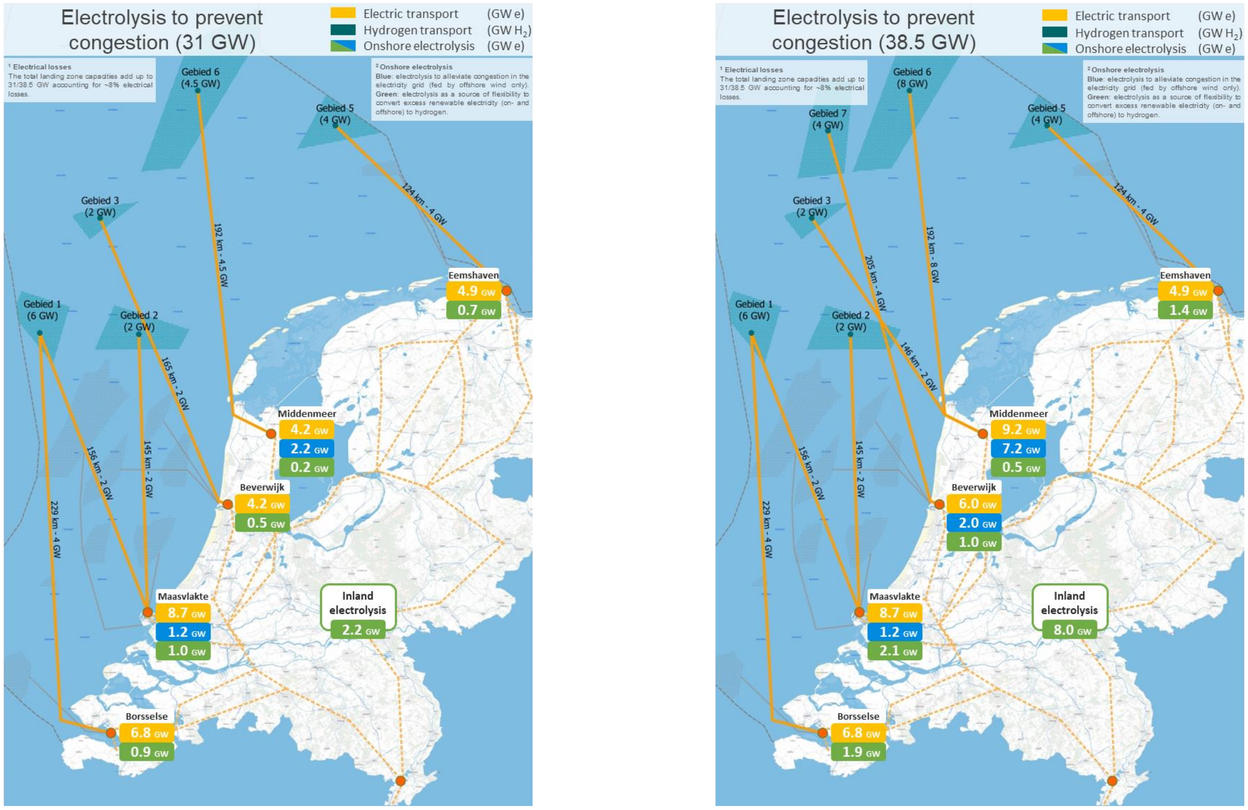


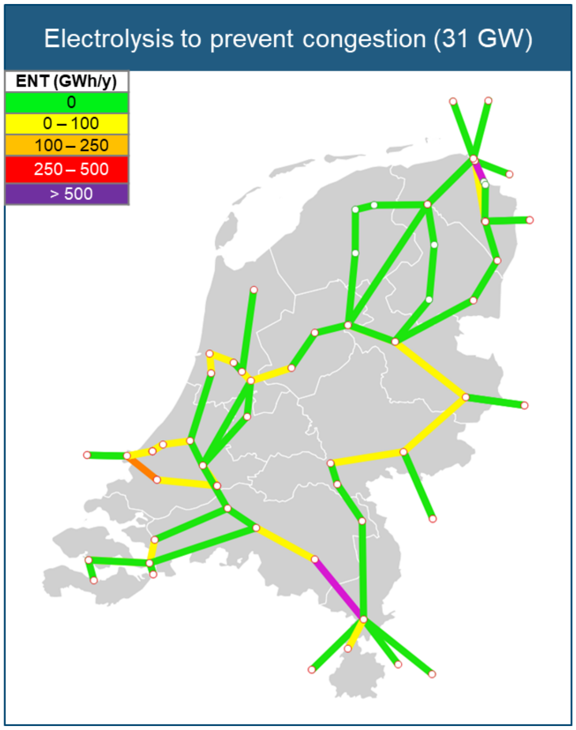
Figure 30: Configurations for solution with all-electric transmission to shore with onshore electrolysis to prevent congestion at landing zone

6.1.3.2 Electricity grid analysis

Because the power input at each landing point is capped, this solution results in similar power for the western Netherlands as in the configuration with coupled electrolysis. As a result, the routes where congestion occurs are also similar, as shown in Figure 31, for both the 31 GW and 38.5 GW configurations. In summary, the main bottlenecks for the solution involving electrolysis to prevent congestion are:

- **Maasvlakte ring**
  This configuration slightly overloads the electricity ring around Maasvlakte, with the expectation this can be resolved operationally.
- **Tilburg–Eindhoven–Maasbracht route**
  The Eindhoven–Maasbracht route is still overloaded. However, as previously stated, the most recently published investment plan (IP2022) provides a solution to this problem. The burden on the Eindhoven–Tilburg route is reduced in this configuration and can be resolved operationally.
- **Diemen region**
  There is a slight overload in the Diemen region, with the expectation this can be resolved operationally.

- **Zwolle–Hengelo route**
  The burden on this route is the same as in the previous solution, with the understanding that the remaining overload is most probably overestimated due to simplification of the interconnection modelling with other countries.



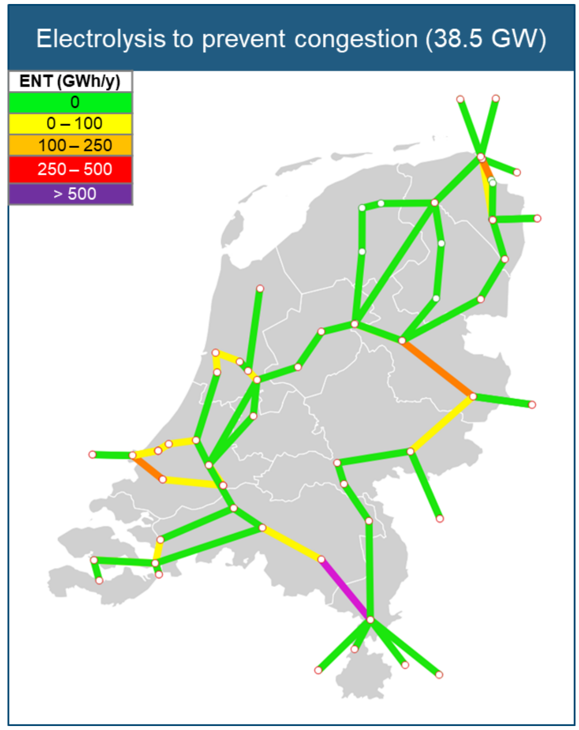


Figure 31: Electricity grid congestion for solution all-electric transmission to shore with onshore electrolysis to prevent congestion at landing zone

Table 13 shows the impact for the main connections on the amount of ENT in both the National and International scenarios.

Table 13: ENT in the National (38.5 GW) and Iinternational (31 GW) scenarios for the main connections for the solution involving electrolysis to prevent congestion compared to previous solutions.

		Energy Not Transported (GWh)		
	Connection	**Landfall focused on Eemshaven**	**Coupled electrolysis**	**Electrolysis to prevent congestion**
National	Amsterdam - Diemen	5	5	14
National	Borssele - Rilland	100	6	10
National	Eindhoven - Maasbracht	1139	485	671
National	Hengelo - Zwolle	570	134	169
National	Maasvlakte - Simonshaven	59	115	121
National	Robbenplaat - Weiwerd	474	144	147
National	Tilburg - Eindhoven	286	67	93
International	Amsterdam - Diemen	2	8	12
International	Borssele - Rilland	1	2	3
International	Eindhoven - Maasbracht	636	542	619
International	Hengelo - Zwolle	206	73	91
International	Maasvlakte - Simonshaven	315	171	180
International	Robbenplaat - Weiwerd	2232	1921	1921
International	Tilburg - Eindhoven	138	59	71

Break-out 7: extra offshore wind capacity (38.5 GW) International scenario

As described, the bottleneck within the planned hydrogen network lies in transporting hydrogen from the storage facilities to the hydrogen power plants during times of low electrical yields from renewable sources (including offshore wind, onshore wind, and solar-PV). A parallel solution to changing the landing configuration of offshore wind is to combine the high hydrogen demand in the International scenario with the offshore wind capacity (and distribution) from the National scenario. Concretely, this means the demand profile of the International scenario is combined with the 38.5 GW offshore wind supply profile of the National scenario, an increase of 7.5 GW. The figure below shows that the effect of this measure on electricity grid congestion is almost negligible. In view of the operating mode of the electrolysers at the landing locations within this solution, this is to be expected, as the maximum electrical capacities to be fed in are maximised on the basis of the feed-in limits of the landing locations.

As can be seen in the figure below, the effect of this measure on electricity grid congestion is almost negligible. In view of the operating mode of the electrolysers at the landing locations within this solution, this is to be expected, as the maximum electrical capacities to be fed in are maximised on the basis of the feed-in limits of the landing locations.

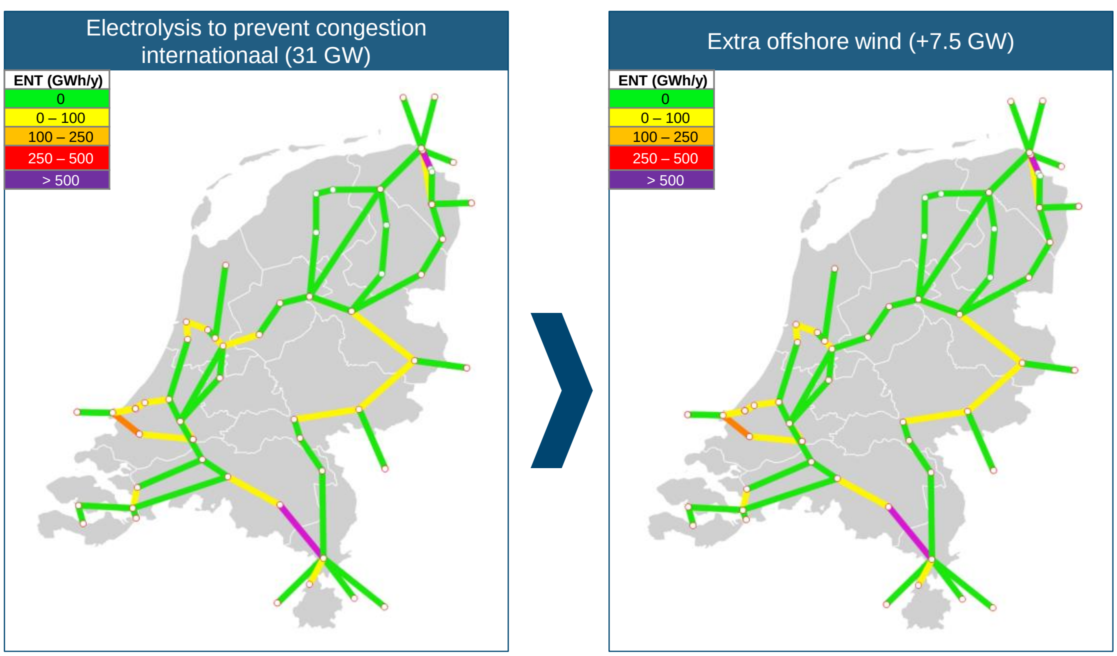


Table 14 shows the impact for the main connections on the amount of ENT in the International scenario presented in break-out 7 above.

Table 14: ENT for the international scenarios (31 GW and 38.5 GW variant) for the main connections for the solution involving electrolysis to prevent congestion.

		Energy Not Transported (GWh)	
	Connection	**Electrolysis to prevent congestion**	**Extra offshore wind (+7.5 GW)**
International	Amsterdam - Diemen	12	12
	Borssele - Rilland	3	2
	Eindhoven - Maasbracht	619	703
	Hengelo - Zwolle	91	96
	Maasvlakte - Simonshaven	180	205
	Robbenplaat - Weiwerd	1921	1907
	Tilburg - Eindhoven	71	81

6.1.3.3 Impact on the future hydrogen network

The results of the gas network analysis are broadly consistent with the results for the first solution.

6.1.3.4 Offshore infrastructure costs and electrolysis capacity

Offshore infrastructure costs for this configuration consist entirely of electrical components, since there is no offshore hydrogen production. The difference between the capacity to be landed and the amount of electricity the grid can absorb is converted into hydrogen by means of electrolysis.

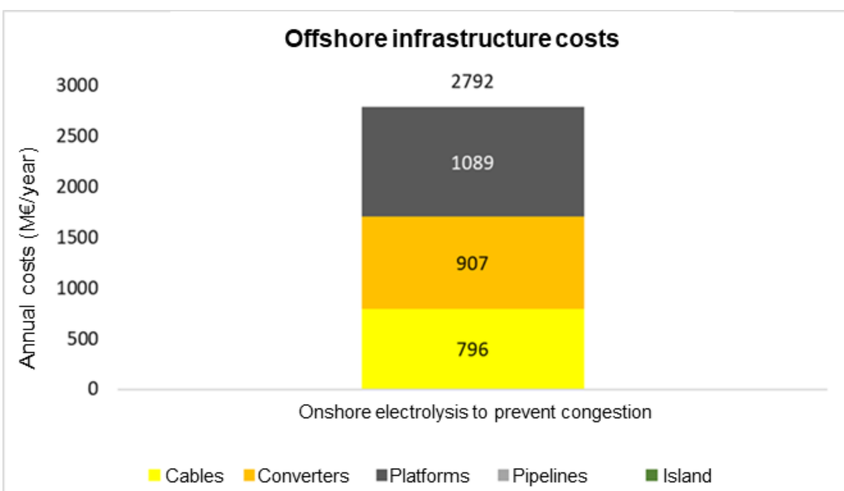


Figure 32: Offshore infrastructure costs for onshore electrolysis to prevent grid congestion (National scenario, 38.5 GW of offshore wind)

Where electrolysis is only used to prevent grid congestion, operating behaviour changes. Electrolysis only takes place when the electricity capacity to be fed in exceeds grid capacity, reducing the number of full-load hours compared to coupled hydrogen production. In this case, too, electrolysis is still required as a flexibility tool to achieve a balance between electricity and hydrogen. The table below shows the capacity, full-load hours, and hydrogen production for electrolysis to prevent grid congestion and for additional, flexible capacity. Hydrogen production to prevent grid congestion operates for a significantly higher number of hours than the other, flexible deployment. However, within the preconditions set in this configuration, the number of full-load hours is approximately 1000 less than coupled electrolysis.

Table 15: Comparison of capacity and deployment of electrolysis to prevent congestion and as a flexibility tool

	Electrolysis to prevent congestion	Activated during surplus
Electrolysis capacity (GW_E)	10.4	15
Full-load hours (h)	4001	3043
Hydrogen production electrolysis (TWh_{H2})	30.0	32.8

6.1.4 Combined electricity landing and coupled offshore electrolysis

The last solution considered was coupled offshore electrolysis in the event of the roll-out of 38.5 GW of offshore wind capacity. The offshore electrolysis option is furthest in the future in terms of development (chapter 4), whereby it is not yet clear whether a centralised or integrated variant will be given preference. Coupled offshore electrolysis has a number of the same drawbacks as onshore electrolysis, but it also has a number of advantages in terms of wind farm design and offshore infrastructure costs. The biggest difference to the onshore variant lies in the offshore infrastructure costs.

6.1.4.1 Landing configuration

Figure 33 shows the landing configuration for the solution involving offshore electrolysis. Here, search areas 6 and 7 are connected to Eemshaven by a shared hydrogen pipeline. This configuration has been chosen to gain further insight into the impact on the gas network analysis. The choice between landing in North Holland versus Eemshaven does not have a significant impact on the rest of the energy system. There is 1.2 GW of installed anti-congestion electrolysis capacity at the Maasvlakte landing point to ensure the electricity grid feed-in limits are not exceeded. There is no offshore electrolysis in the areas off the west coast of the Netherlands because this technology is unlikely to become economically and technically feasible (from mid-2030) until after the wind farms have become operational (before 2030).

Figure 33: Configuration for solution involving offshore electrolysis.

6.1.4.2 Electricity grid analysis

As 12 GW (for scenarios involving 38.5 GW offshore wind) of electricity is converted into hydrogen in this configuration, landed electrical power is substantially lower than in the other solutions for almost all landing zones, with Maasvlakte the only exception. In summary, the main bottlenecks for the solution involving offshore electrolysis are:

- **Maasvlakte ring:** This configuration slightly overloads the electricity ring around Maasvlakte, with the expectation this can be resolved operationally.
- **Tilburg–Eindhoven–Maasbracht route:** There is a slight reduction in the overload on this route compared to the solution involving onshore electrolysis to prevent congestion.
- **Zwolle–Hengelo route:** The burden on this route is the same as in the previous solution, with the understanding that the remaining overload is most probably overestimated due to simplification of the interconnection modelling with other countries.

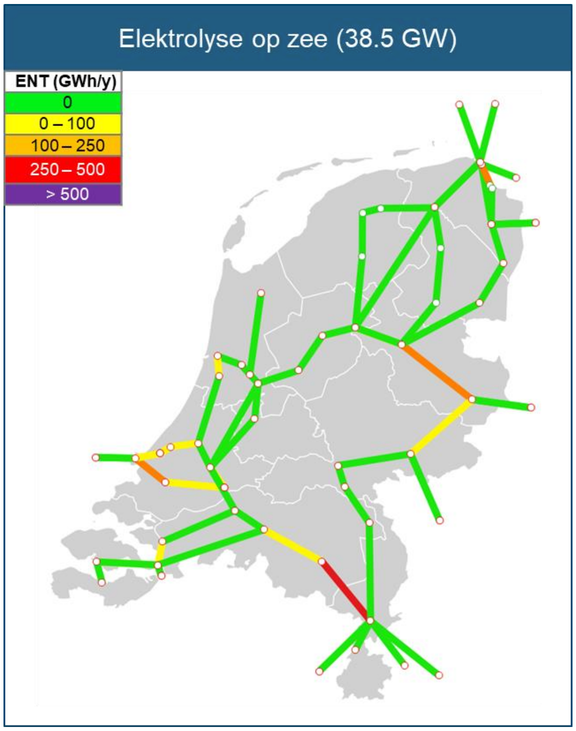


Figure 34: Electricity grid congestion for solution involving offshore electrolysis

Table 16 shows the impact for the main connections on the amount of ENT in the National scenario compared to previous solutions.

Table 16: ENT in the National (38.5 GW) scenario for the main connections for the solution involving part of the offshore electrolysis capacity compared to the previous solutions.

		Energy Not Transported (GWh)		
	Connection	**Landfall focused on Eemshaven**	**Coupled electrolysis**	**Offshore electrolysis**
National	Amsterdam – Diemen	5	5	0
	Borssele - Rilland	100	6	11
	Eindhoven - Maasbracht	1139	485	395
	Hengelo - Zwolle	570	134	103
	Maasvlakte - Simonshaven	59	115	136
	Robbenplaat - Weiwerd	474	144	135
	Tilburg - Eindhoven	286	67	39

Table 17 shows the impact on the amount of ENT for the main connections in the International scenario in Break-out 8 above compared to the National scenario involving offshore electrolysis.

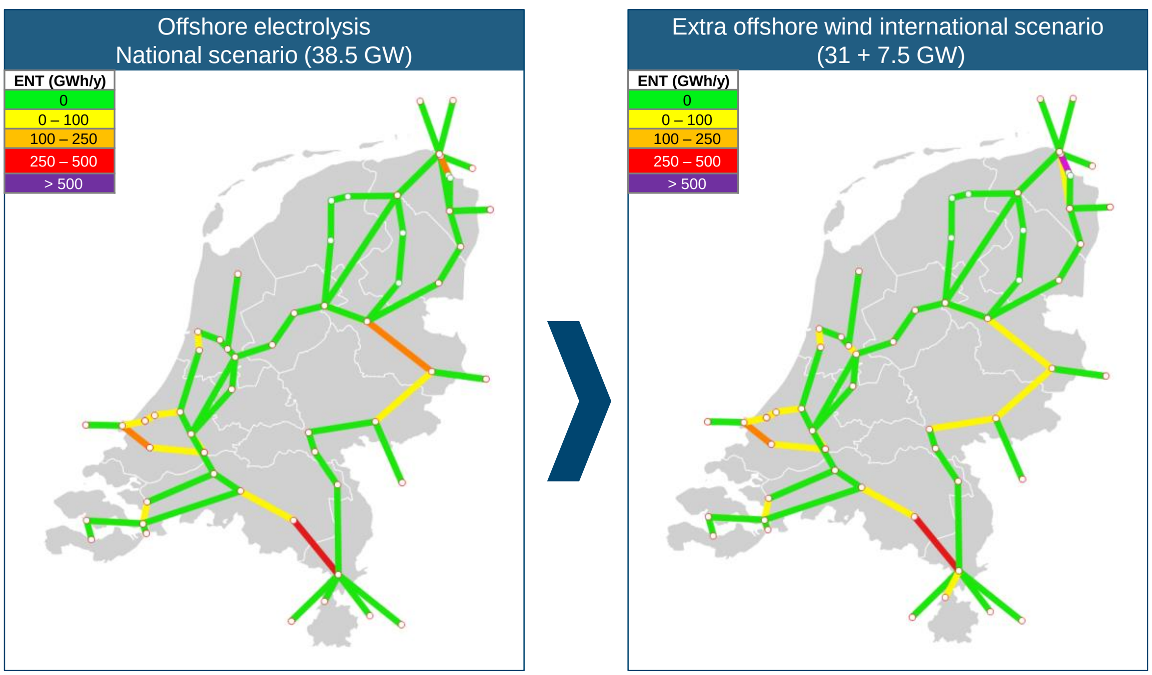
Table 17: ENT in the National scenario (38.5 GW) and the International 38.5 GW variant for the main connections for the solution involving offshore electrolysis.

		Energy Not Transported (GWh)	
	Connection	**Offshore electrolysis (National)**	**International Extra offshore wind (+7.5 GW)**
Zie headers	Amsterdam - Diemen	0	0
	Borssele - Rilland	11	5
	Eindhoven - Maasbracht	395	377
	Hengelo - Zwolle	103	49
	Maasvlakte - Simonshaven	136	215
	Robbenplaat - Weiwerd	135	1952
	Tilburg - Eindhoven	39	28

Break-out 8: extra offshore wind capacity (38.5 GW) international scenario

The effect of extra offshore wind for the International scenario has also been examined for the offshore electrolysis solution. However, because offshore electrolysis does not seem to be beneficial for a 31 GW offshore wind scenario, no direct comparison with the International scenario can be made. However, it is possible to examine what effect the different supply and demand profile of the International scenario would have on congestion of the electricity and hydrogen grids, if the offshore wind capacity was the same as the National scenario.

The figure below shows that the effect of a different supply and demand profile for the offshore electrolysis solution on congestion in the electricity grid is very small. The effect on congestion in the gas network is also minimal. Despite the greater demand for hydrogen (which is a fairly continuously increased baseload), the periods with little generation of renewable energy remain, which must be met by hydrogen gas plants. The effects are a result of the choice of scenario, not of the landing configuration) of offshore wind (and location and operational mode of the electrolysers).



6.1.4.3 Impact on the future hydrogen network

The results of the gas network analysis are broadly consistent with the results for the first solution.

6.1.4.4 Offshore infrastructure costs and electrolysis capacity

The solution with coupled offshore electrolysis involves a hybrid connection to land. Areas 6 and 7 are connected by hydrogen pipelines, while the other areas are connected with HVDC cables. This has an impact on total infrastructure costs for this configuration. Figure 35 shows the distribution of the total offshore infrastructure costs compared to coupled onshore electrolysis. Some of the cable costs have been replaced with pipeline costs, and some of the platform costs by the costs of a centralised energy island. The largest contributing factor in reducing costs is the lower number of HVDC converters required to bring energy to land. Hydrogen compression is an additional cost item for offshore electrolysis; however the additional costs are outweighed by cost benefits.

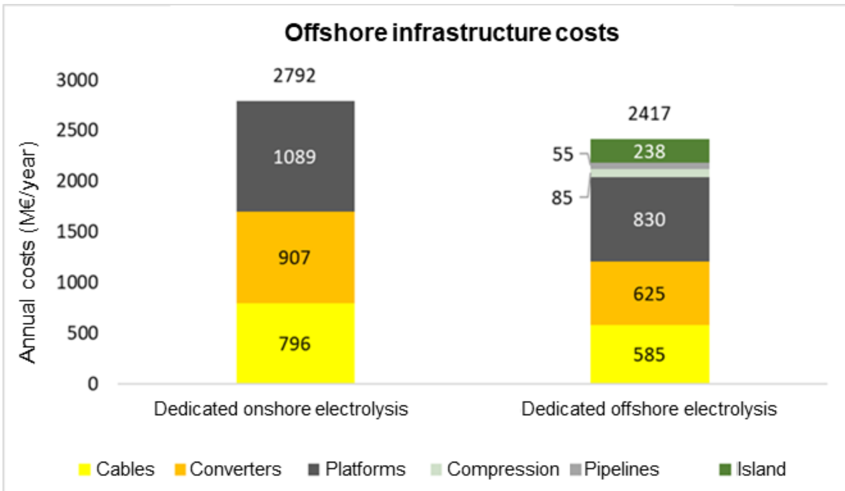


Figure 35: Offshore infrastructure costs for offshore electrolysis (National scenario, 38.5 GW of offshore wind)

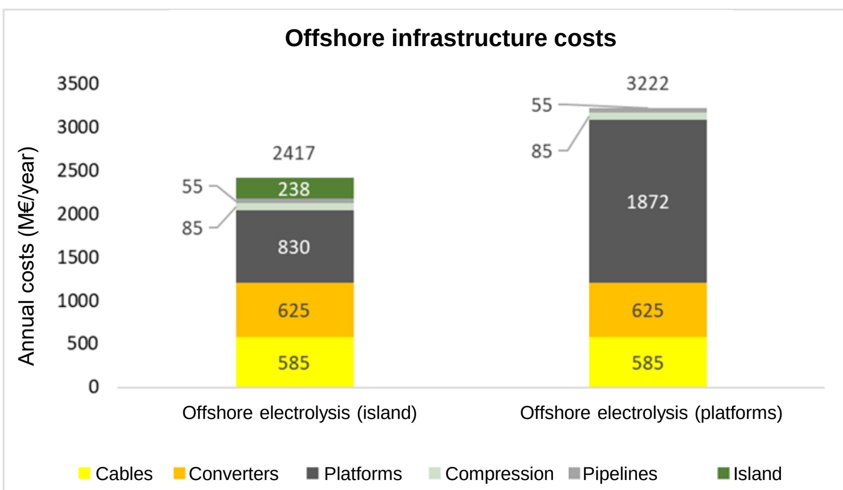
Installation of offshore electrolysis has a significant impact on the operational capacity of the overall electrolysis capacity. This solution involves three types of electrolysis: coupled offshore electrolysis, electrolysis to prevent congestion (only 1.2 GW), and electrolysis as a flexibility tool. Coupled offshore electrolysis operates at 5000 full-load hours per year, as there are no conversion and transport losses. Thanks to the high capacity and high number of full-load hours, the largest proportion of domestic green hydrogen production comes from offshore electrolysis. Electrolysis to prevent congestion is the least used, due to the ratio of electricity landed from offshore wind to the feed-in limit at Maasvlakte. Electrolysis as a flexibility tool produces 2800 full-load hours per year, driven by competition with hydrogen imports and the residual demand profile. It should be noted that removing 12 GW of offshore wind energy from the national electricity grid has a significant impact on this residual demand profile, and therefore also the use of electrolysis as a flexibility tool and gas-fired power plants.

Table 18: Comparison of electrolysis for large-scale landing in Maasvlakte versus Eemshaven

	Offshore, coupled electrolysis	Electrolysis to prevent congestion	Activated during surplus
Capacity electrolysis (GW_E)	12	1.2	13.3
Full-load hours (h)	5000	2545	2800
Hydrogen production electrolysis (TWh_{H2})	44.4	2.2	26.9

Break-out 9: Offshore P2G on platforms

The solution of offshore electrolysis is based on a central P2G island. An alternative is to place electrolysis on multiple platforms. This has no impact on the energy balance on land and at sea, but it does have an impact on infrastructure costs. It is assumed a single platform can accommodate 500 MW of electrolysis capacity. 24 platforms are needed to host 12 GW of offshore electrolysis. The costs for this variant of the solution are shown in the figure below. It is immediately apparent that the use of platforms is significantly more expensive than islands for such quantities of offshore electrolysis. Other costs are the same, because there is the same amount of accessible offshore wind generated electricity and pipeline capacity (and compression) to the coast.



6.1.4.5 Estimated value of a hybrid hydrogen-electricity connection

In addition to the configuration whereby all offshore wind energy is converted into hydrogen, a hybrid connection is possible whereby both electricity and hydrogen are landed.

Market modelling is required to determine the value of the hybrid configuration. This modelling has not been carried out within the scope of this study. We can use the analysis tools in this study to produce a simplified estimate of the value, to identify the order of magnitude.

This approach involves comparing the costs of the additional HVDC infrastructure to the benefits of direct supply of electricity to end users (without the intermediate step via hydrogen).

The situation is based on:

- 12 GW of offshore wind energy (areas 6 and 7), with an electricity connection to an energy island that has 12 GW of electrolysis capacity.
- HVDC connection from area 6 to Eemshaven, varied capacity.
- There is an electricity connection between the 12 GW of offshore wind energy and an HVDC converter on the island, which is limited to the capacity of the connection (the electrical infrastructure on the island acts like a copper plate).
- The advantages of direct electricity supply have been identified as the difference between the costs of electricity from hydrogen power plants and the value of hydrogen (taken as the import price).
- The existence of a shortage of renewable electricity is determined on an hourly basis. The HVDC connection is deployed for the hours when there is a shortage (and less P2G is applied).

We calculate the marginal costs and benefits per added GW HVDC capacity[44]. The marginal costs intersect with the marginal benefits in the case of an HVDC capacity of around 3 GW, which is the optimum capacity for this situation.

[44] In practice, economies of scale can occur with the use of 2 GW HVDC connections compared to 1 GW connections. This has not been taken into account in this analysis.

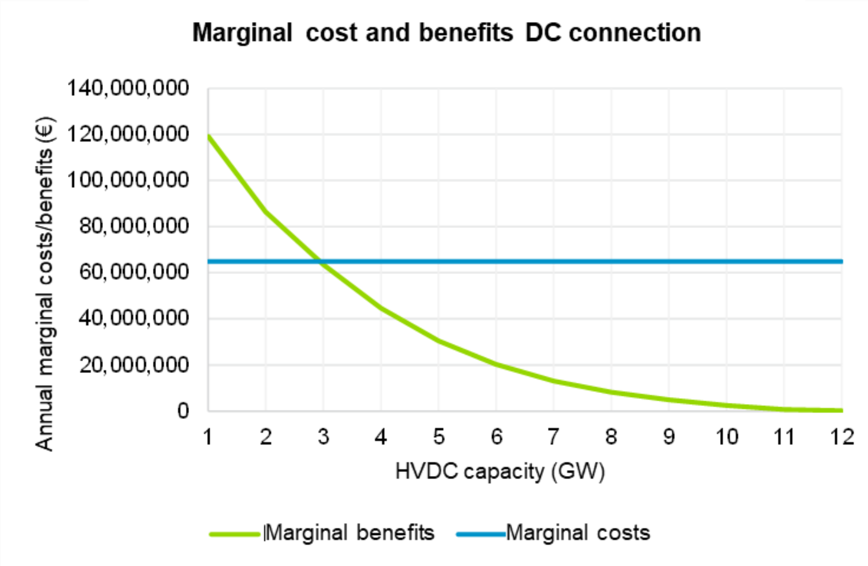


Figure 36: Marginal costs and benefits of adding a DC connection to an energy island with offshore electrolysis

In this scenario, the addition of the 3 GW HVDC connection results in a net benefit of €75 million per year. It reduces the number of hours of green energy shortages from 3080 to 2710 hours (-370 hours). The marginal benefits are strongly influenced by the form and size of the residual demand profile and the offshore wind energy production profile. As HVDC capacity increases, the utilisation (capacity factor) of this infrastructure decreases; at the optimum level of 3 GW, this factor is 19%.

To gain an insight into the sensitivity of the optimum HVDC capacity to offshore wind energy capacity, the same analysis was carried out with an offshore wind energy capacity of 6 GW and 24 GW. This results in an optimum HVDC capacity of 2 GW and 4.5 GW respectively. The sensitivity is therefore relatively low and there is no constant ratio between offshore wind energy capacity and optimum HVDC capacity.

6.2 System impact of solutions

The previous section describes the results of the solutions in sequential order, with a focus on impact on the electricity system, use of electrolysis, and infrastructure costs. This section will consider the broader system impact of the solutions for the National (38.5 GW of offshore wind) scenario. It should be noted the system impact of the solutions that use electrolysis only in the event of surpluses (‘all-electric’) is the same due to the copper plate principle in the modelling, regardless of landing location. The key aspects affecting system impact are:

- Electrolysis operating behaviour
- Hydrogen demand and hydrogen import
- Curtailment
- G2P operating behaviour
- Import and export of electricity

To better interpret the results and explain differences, the residual demand profiles of the four solutions are shown in Figure 37. Here, residual demand is the overall demand for electricity minus renewable electricity production (electrolysis coupled to offshore wind energy therefore does not contribute to directly reducing residual demand, however it does reduce the amount of renewable energy sources (RES) which directly contributes to reducing electricity demand). If residual demand is positive (left side of the curve), there is not enough renewable electricity to meet demand. This demand is met using flexibility tools: import, battery discharge, and gas-fired and hydrogen power plants. If residual demand is negative, there is surplus renewable electricity. This surplus is also dealt with using flexibility tools: export, battery charging, use of electrolysis, and curtailment. Peak residual demand is almost the same for the four solutions, and around the same as peak electricity demand.

For an overview of the results of the flexible modelling and electrolysis optimisation for all scenarios and solutions[45] see appendix C, Table 21 to Table 25. These tables clearly show the interplay between curtailment, electrolysis, gas-fired power plants, batteries, and import/export of electricity.

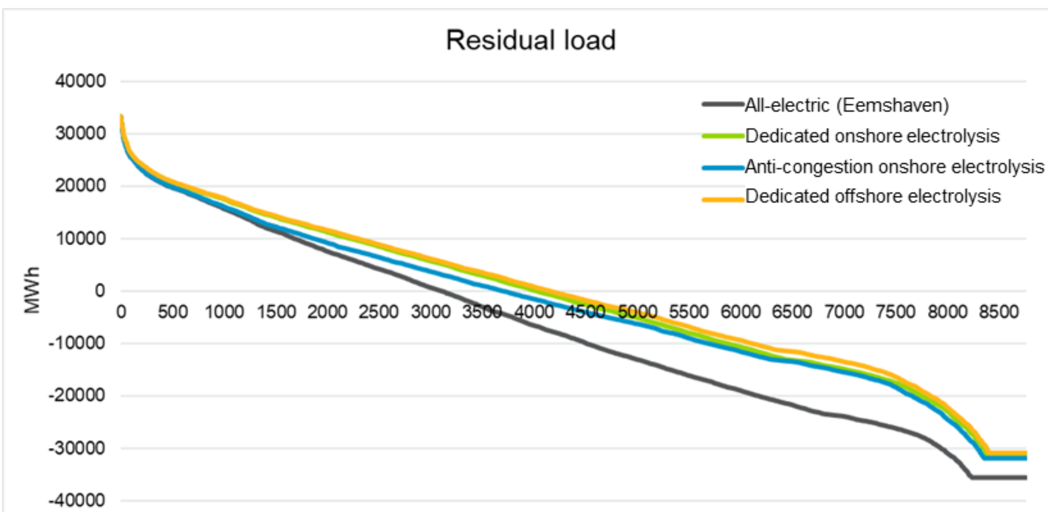


Figure 37: Residual demand profile of the four solutions in the International scenario

Full-load hours and total domestic hydrogen production are key indicators for the use of electrolysers. Figure 38 shows the number of full-load hours, while Figure 39 shows total domestic hydrogen production. Electrolysis as a flexibility tool shows a lower number of full-load hours for the solutions with coupled electrolysis (onshore and offshore). This is because a large proportion of electricity from offshore wind is used directly for hydrogen production. The total amount of negative residual demand (surplus renewable electricity) over the year is therefore lower. The solution in which electrolysis is only used in the event of surpluses (‘all-electric’) also shows the lowest total domestic hydrogen production, due in part to the absence of coupled electrolysis or anti-congestion electrolysis (with a high number of

[45] For an explanation of the term ‘solutions’, see chapter 6

full-load hours each year), but also due to the shape of the residual demand profile (see Figure 37). If all offshore wind energy is landed as electricity, this has an impact on peak negative residual demand. The middle section of the curve remains almost the same after the deployment of flexibility tools (this is not visible in Figure 37, however, as this figure shows the residual demand profile for the deployment of flexibility tools).

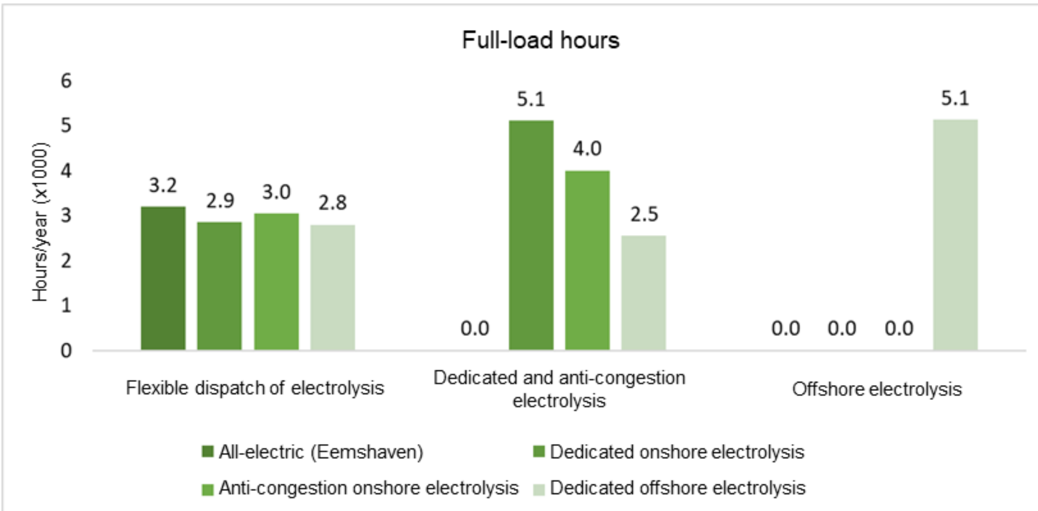


Figure 38: Electrolysis full-load hours for the four solutions in the National scenario

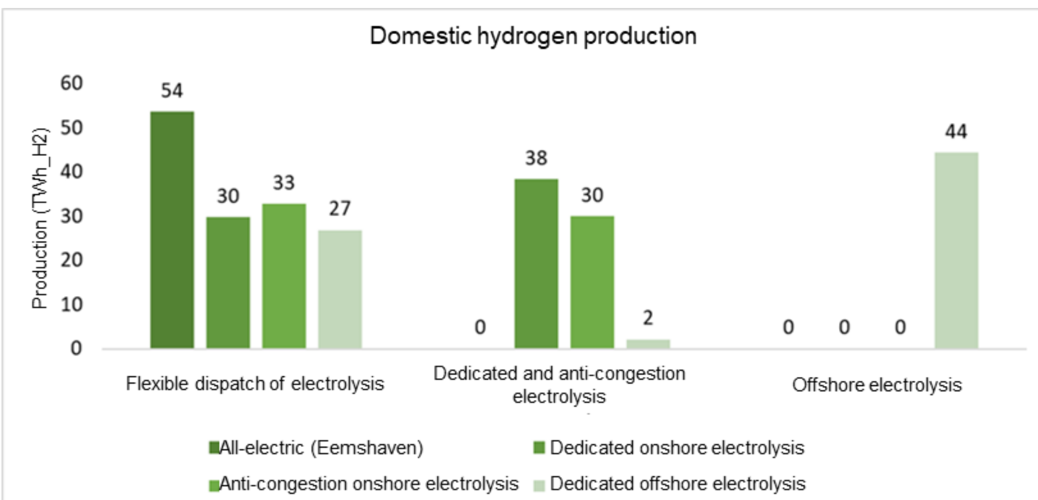


Figure 39: Domestic hydrogen production for the four solutions in the National scenario

Impact on hydrogen demand and hydrogen import is shown in Figure 40 and Figure 41. It should be noted that part of the hydrogen demand is met by blue and grey hydrogen (import plus domestic production therefore does not add up to total hydrogen demand). The solutions with coupled electrolysis and electrolysis to prevent congestion involve a greater demand for hydrogen in the electricity sector, as not all the electricity from offshore wind is fed into the electricity grid. Demand in other sectors is the same in all four solutions. The difference in hydrogen demand and domestic hydrogen production is offset by the import of green hydrogen from abroad. Both onshore and offshore coupled electrolysis therefore results in greater total hydrogen demand, and although domestic hydrogen production is also greater in these solutions, a substantial amount of hydrogen still needs to be imported.

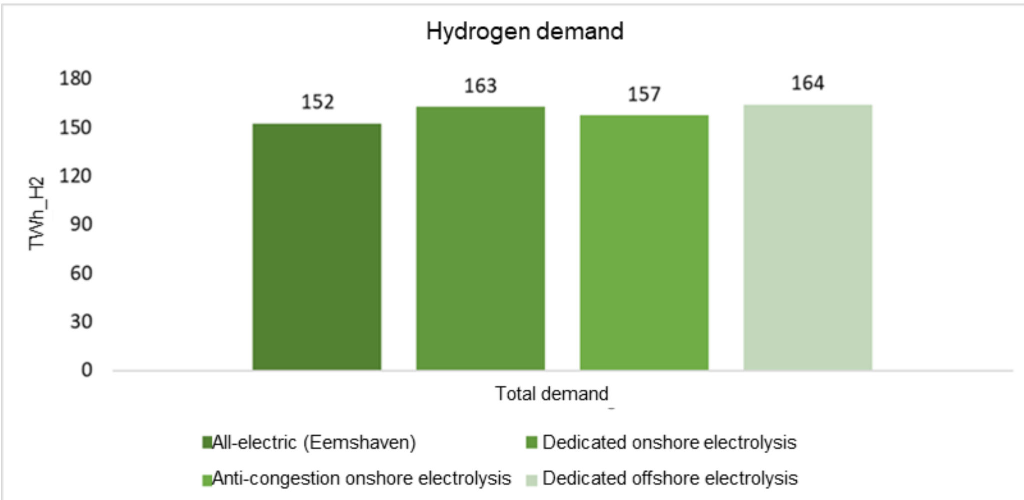


Figure 40: Hydrogen demand for the four solutions in the National scenario

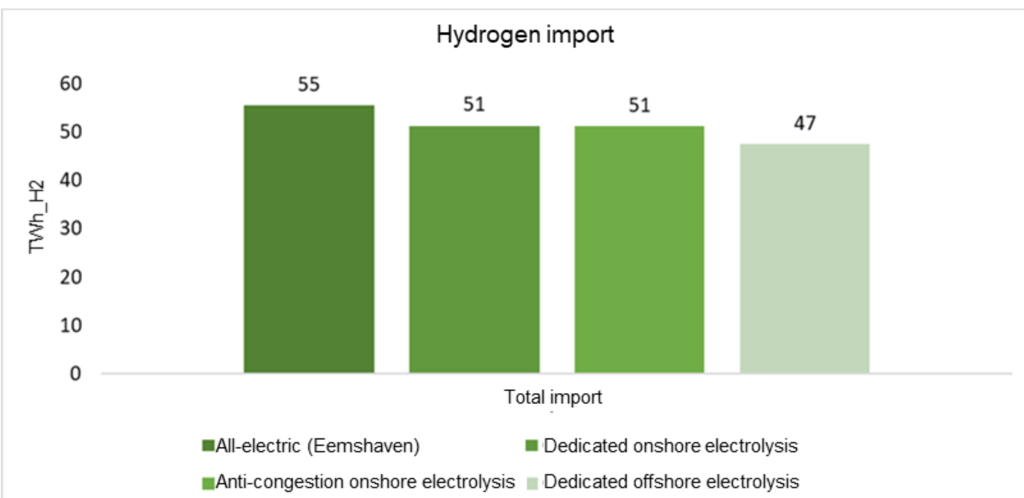


Figure 41: Hydrogen import for the four solutions in the National scenario

Curtailment of renewable electricity occurs when there is no economically viable way of absorbing surpluses through electrolysis. Figure 42 shows the amount of curtailment in one year for the four solutions. It is worth noting that the solution in which electrolysis is only used in the event of surpluses ('all-electric') shows the largest amount of curtailment (in both TWh_e and percentage of total renewable electricity production). For the solutions with coupled or anti-congestion electrolysis, the amount of offshore wind energy that enters the grid in the form of electricity is limited by the direct link to electrolysis. It is worth noting that greater use of electrolysis, as in the last three solutions, also results in greater conversion losses.

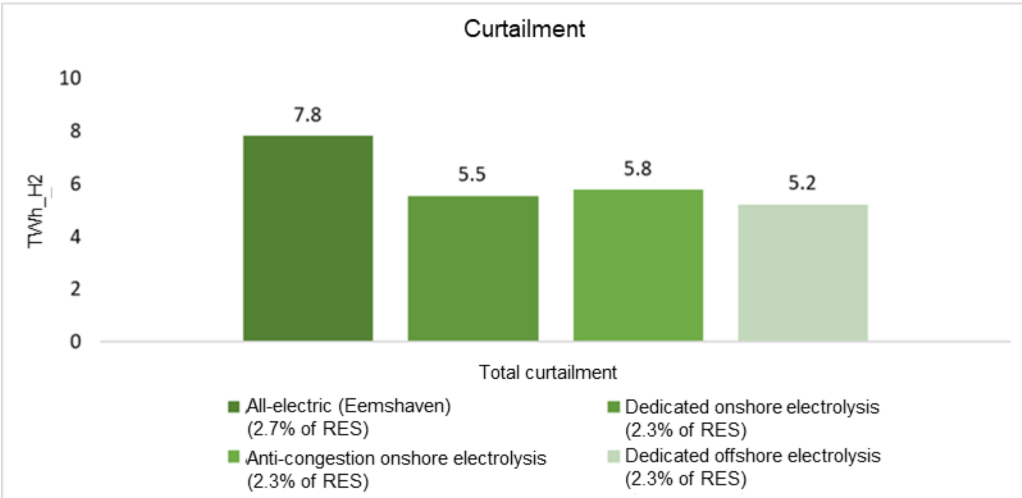


Figure 42: Curtailment of renewable electricity for the four solutions in the National scenario

Gas-to-power (G2P) operating behaviour is described by the total annual electricity production from G2P, as shown in Figure 43. G2P capacity is the same in all of the solutions (5 GW for natural gas-fired power plants, 24 GW for hydrogen power plants), since this is driven by peak residual demand, which is the same in all four solutions. The solutions with coupled electrolysis show a higher use of G2P, as not all the energy from offshore wind is directly used to meet electricity demand. The low number of full-load hours for G2P (approx. 1000 hours per year) raises the question of whether the current market structure offers sufficient incentives to invest in new capacity.

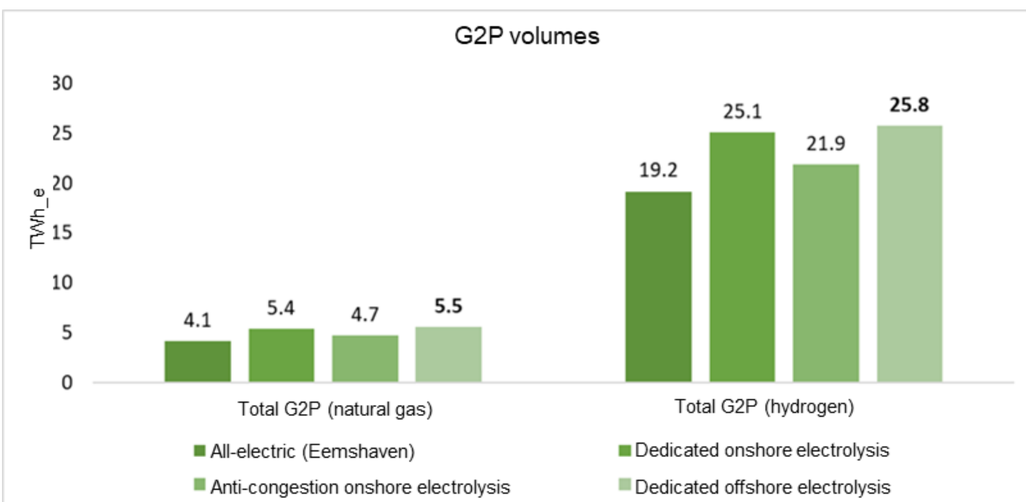


Figure 43: Electricity production from gas-fired power plants for the four solutions in the National scenario

The use of electrolysis in the four solutions also has an impact on **import and export of electricity**. Figure 44 shows there is considerable export in the solution where electrolysis is only used in the event of surpluses ('all-electric') compared to the other options. The electricity produced by the 38.5 GW of offshore wind capacity therefore exceeds national demand, including economically profitable domestic hydrogen production. Coupled electrolysis means a large part of the 38.5 GW of offshore wind is direct converted into hydrogen, so less electricity ends up in the grid and is less electricity is exported. In fact, the coupled offshore electrolysis solution results in net import of electricity.

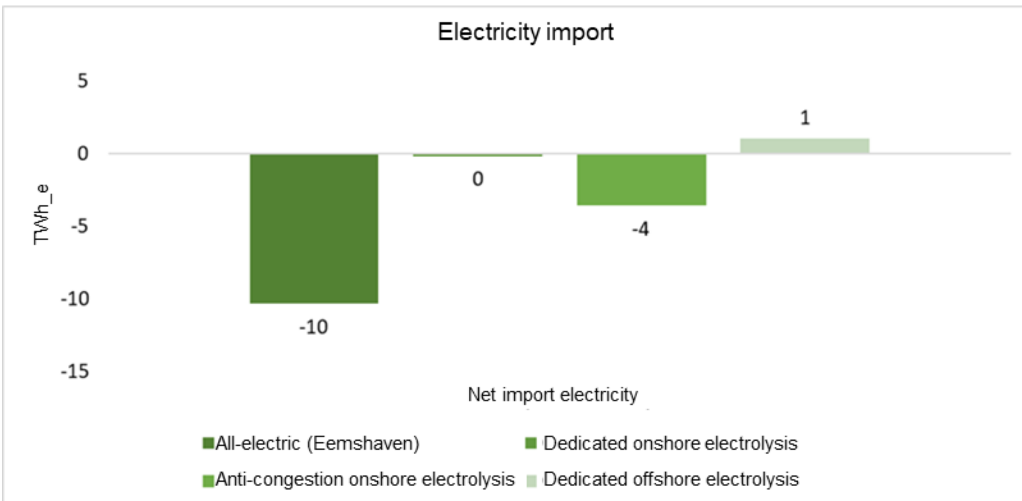


Figure 44: Net import (a negative value signifies export) of electricity for the four solutions in the National scenario

6.3 Key differences between scenarios

The scenarios differ in terms of energy supply and demand. In each scenario, supply also depends on the chosen solution. The differences in supply are presented in this chapter, which also looks at the impact of the scenarios on the electricity and hydrogen grids.

6.3.1 Supply of hydrogen and electricity in each scenario

II3050 outlines energy scenarios for 2050, in which the supply of hydrogen and electricity varies considerably. In our 2040 interpolation, a big difference has arisen for hydrogen supply, whereas electricity supply is still very similar in the scenarios. This section looks at the supply of hydrogen and electricity in the four scenarios and the two variants. The results presented here reflect annual supply based on solution 3, taking into account the various flexibility options. These figures are exclusive of imports required to meet demand from international transport (aviation and shipping). See Appendix B for supply and demand figures including international transport.

Hydrogen supply

Hydrogen supply for 2040, according to the II3050 demand-based scenarios, is shown in Figure 45. Supply is lowest in the Regional scenario, where it consists of approximately two-thirds green hydrogen. Grey hydrogen plays a smaller role than blue hydrogen role in this scenario. In the National scenario, hydrogen is used for the same purposes as in the Regional scenario. However, hydrogen supply is greater than in the Regional scenario as there is a larger number of GW installed wind and solar capacity, of which 7.5 GW is offshore. Hydrogen demand is higher in the European scenario than in the Regional and National scenarios, and demand for blue hydrogen is also highest. This is because the ambition for self-sufficiency is abandoned in this scenario with other types of hydrogen able to compete with domestic green production. This means hydrogen can be used in more places in the energy system. In this scenario, back-up power stations in the electricity sector run more on green gas or natural gas. Consequently, hydrogen demand remains significantly lower than if these power stations were to run on hydrogen as in the other three scenarios (+- 100 PJ).

We anticipate the greatest supply of hydrogen in the International scenario. Developments we see in the International scenario are largely the same as those in the European scenario. The main difference is that, in the International scenario, dispatchable electricity production capacity runs on hydrogen and there is considerable demand for hydrogen from the built environment (due to hybrid heat pumps). In the International scenario, a large role is reserved for hydrogen imports: the imported volume is two thirds of overall demand and, in itself, greater than total demand in the other three scenarios. Total hydrogen supply in the International + additional offshore wind energy scenario is similar to the International scenario. A larger proportion is generated domestically in the International + additional offshore wind energy scenario than in the International scenario, due to the surplus renewable electricity in this scenario. In the National + additional electrification scenario, a large part of industry is electrified, which means hydrogen demand is lower in this scenario than in the National scenario. The amount of blue and grey hydrogen is the same in both the National and National + additional electrification scenarios.

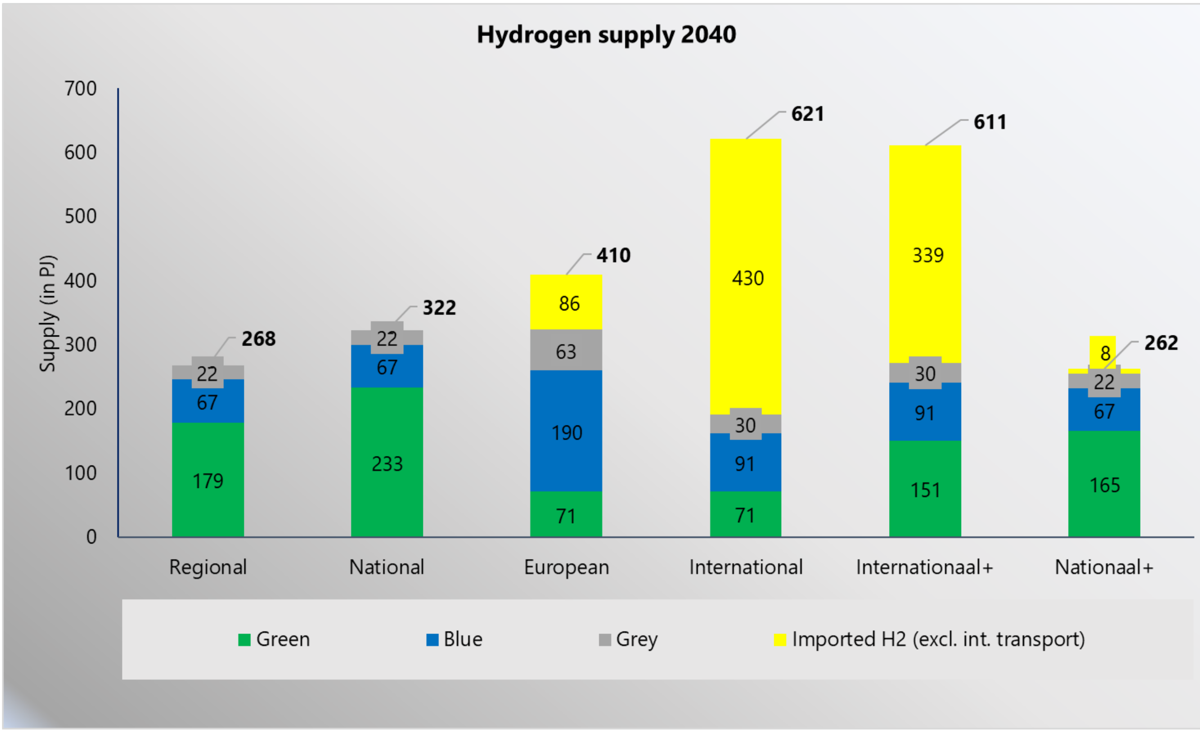


Figure 45. Hydrogen supply in the 2040 scenarios (based on the solution involving electrolysis to prevent congestion). International + assumes additional offshore wind energy, reducing dependence on imports. National+ assumes electrification of industry, reducing the supply of electricity from offshore wind for electrolysis (and the demand for green hydrogen).

Electricity supply

Supply of electricity in 2040 is shown in Figure 46. The differences between the scenarios here are noticeably smaller than for hydrogen supply. Supply of electricity is higher in the Regional and National scenarios than in the others. In the case of the Regional scenario, this is due to a larger installed solar PV capacity, and in the National scenario, it is due to the assumed larger GW of offshore wind. Electricity imports are limited as these scenarios aim for a large degree of self-sufficiency; partly for this reason, the use of hydrogen power plants is considerably higher than in the European and International scenarios.

The European and International scenarios are very similar. Demand for electricity in the energy sector is lower in these scenarios, mainly because the self-sufficient world view is abandoned in them. Electrolysis capacity is used mainly for surpluses. More renewable electricity is generated in the International + additional offshore wind energy scenario than in the International scenario, due to greater offshore wind energy capacity. However, the increase in offshore wind energy capacity exceeds usable supply. More energy is generated in the National + additional electrification scenario than in the National scenario. This is because demand for electricity is higher, resulting in less curtailment and less coupled electrolysis.

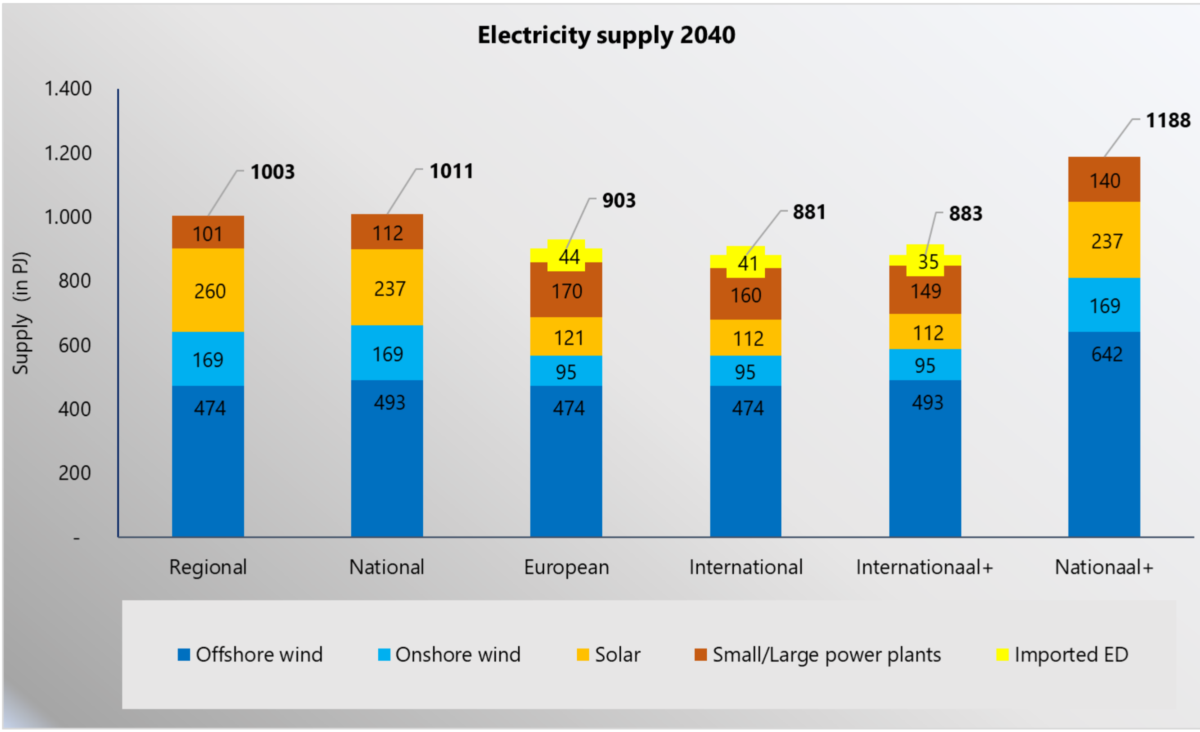


Figure 46: Electricity supply in the 2040 scenarios (based on the solution involving electrolysis to prevent congestion).

6.3.2 Differences in results between scenarios: electricity grid

There are marked differences between the various solutions when it comes to electricity grid congestion. This section provides an overview of the differences between the scenarios. The comparison is relatively brief, as comparing scenarios provides no insight into the impact of decisions in relation to landing and/or electrolyser operating mode, but instead primarily demonstrates the impact of decisions in the demand and supply profile of the various scenarios.

Figure 47 shows electricity grid congestion for the solution with a focus on Eemshaven, while Figure 48 shows congestion levels under the solution involving electrolysis to prevent congestion. For the solutions without electrolysis to prevent congestion, the National scenario (with 38.5 GW of offshore wind energy) shows the most grid congestion. In terms of the 31 GW scenarios, the level of congestion is neck and neck between the European and International scenarios, which both show almost the same load on the electricity grid as the Regional scenario.

It is also worth noting there is little difference in load on the electricity grid between the solutions with electrolysis to prevent congestion (including the scenario with offshore electrolysis). This is because the landing site feed-in limit is not exceeded to a significant extent in any of the scenarios, which means the scenarios are very similar in terms of input of electrical power from offshore wind. Differences in grid load will therefore mainly result from the demand and supply profiles of the various scenarios.

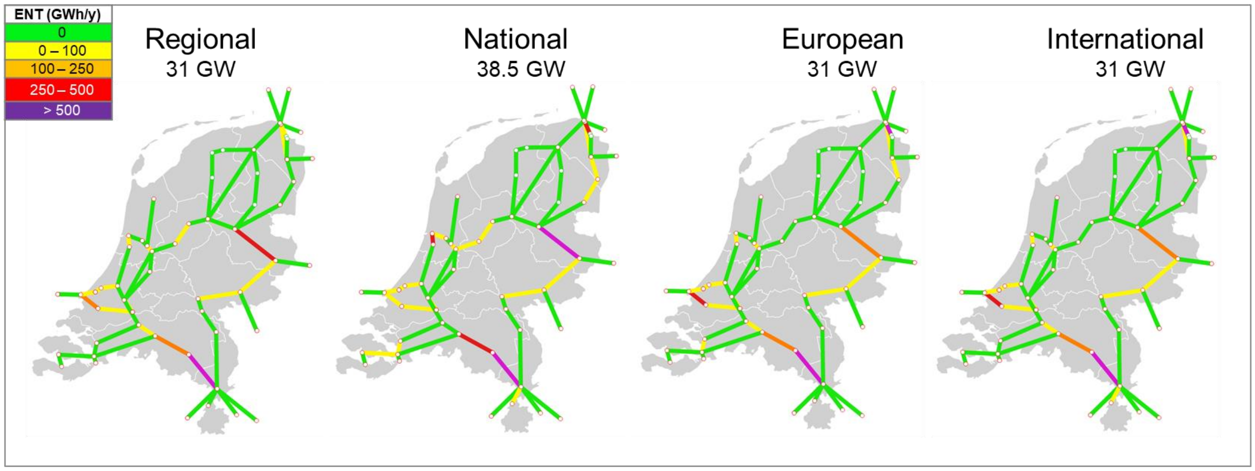


Figure 47: Electricity grid congestion in the case of a all-electric solution with a focus on Eemshaven.

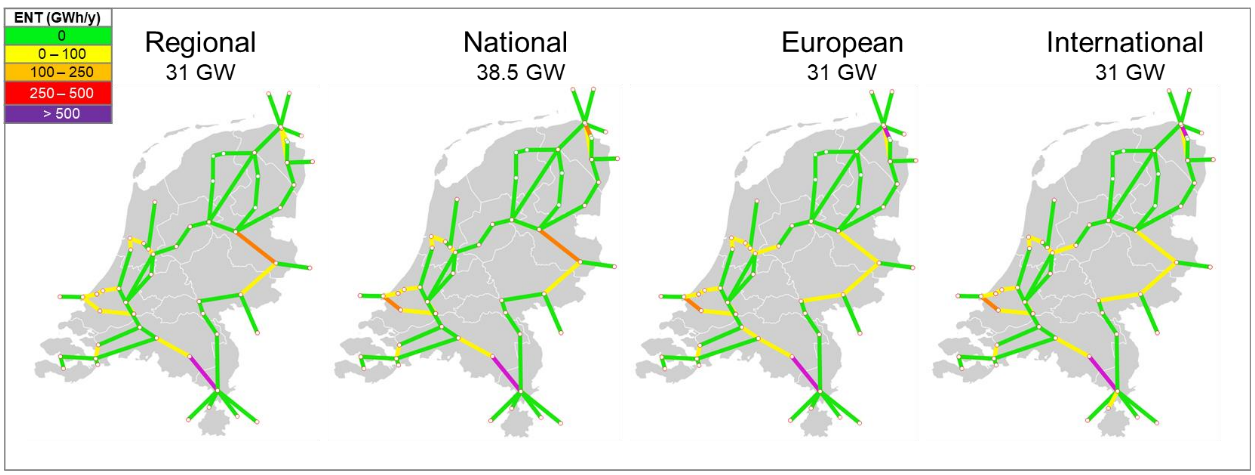


Figure 48: Electricity grid congestion in the case of a all-electric solution with electrolysis to prevent congestion.

6.3.3 Differences in results between scenarios: hydrogen network

Landing point 'snapshots' (as described in section 5.6.2) have been created for the hydrogen network based on the different solutions. Figure 49 shows minimum and maximum hydrogen supply capacity at a landing point for the various snapshots.

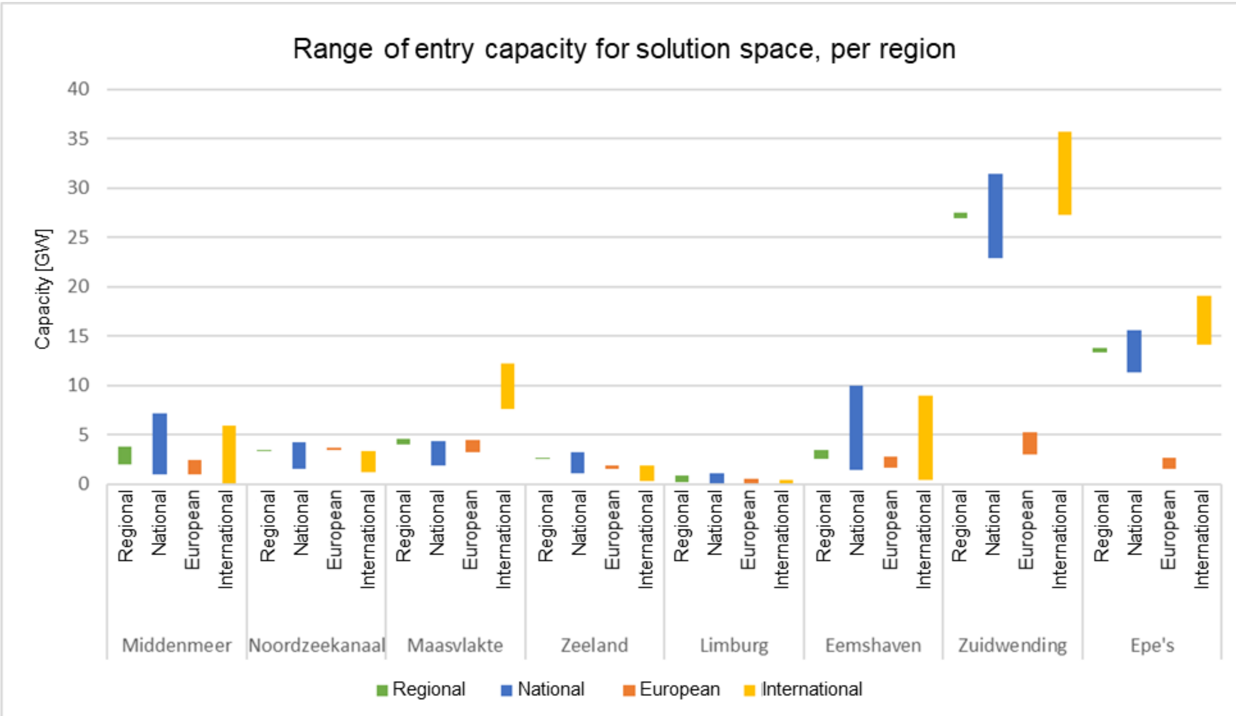


Figure 49: Distribution of entry capacity across all solutions per region for the planned hydrogen network.

What is striking is that entry from the storage facilities (Zuidwending and Epe, the two categories furthest to the right) dominates. For all except the European scenario, entry capacity at these storage locations is many times higher than capacity at the other locations where offshore wind energy is landed in the form of electricity (whereby a proportion is converted into hydrogen using onshore electrolysis plants) or hydrogen (whereby conversion takes place offshore). This chart therefore shows the landing point does not determine the required capacity of the hydrogen network. However, the high entry capacities from storage facilities in the East (Epe) and North (Zuidwending) of the country determine the scale of measures required in the hydrogen network.

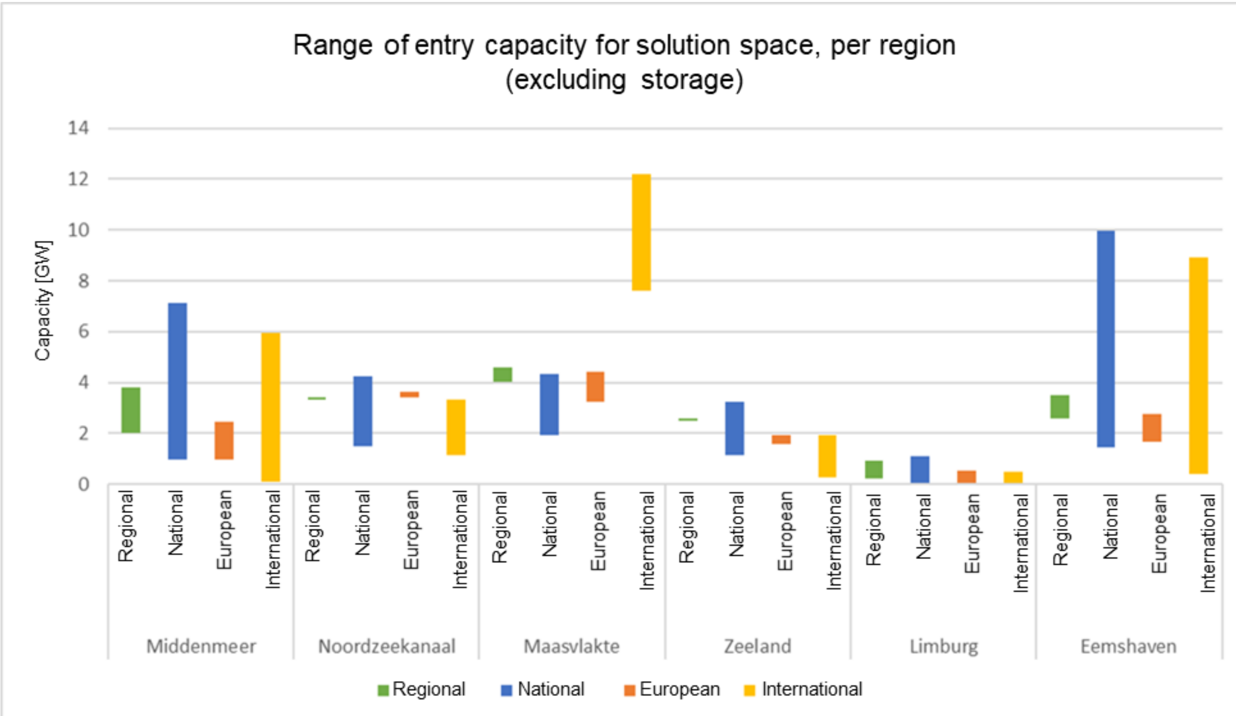


Figure 50: Distribution of entry capacity across all solutions per region (excluding storage) for the planned hydrogen network.

Figure 50 shows the capacity range per region that has been adjusted by changing the landing zones. These charts also show the European scenario is the lightest scenario for the hydrogen network. Although Figure 50 shows that entry capacity from the landing regions is similar to other scenarios, Figure 49 reveals the big difference between the European scenario and the other scenarios is entry capacity from the storage facilities. This is because the storage facilities' maximum output capacity is determined by demand from hydrogen power plants. When no electricity is produced from sun and wind, power plants (gas and/or hydrogen) supply electricity at that time. In the European scenario this will be gas-fired power plants (methane), as opposed to (more or less) gas-fired power plants (methane) and hydrogen power plants in the other scenarios. As hydrogen power plants are not used in the European scenario and therefore do not determine peak hydrogen demand, no additional measures are needed compared to the planned hydrogen network in 2030. The basic network, as described in section 3.4, is therefore adequate. Please note, this study did not assess whether the natural gas network (methane) has sufficient capacity to supply the power stations in the European scenario.

In the other scenarios, the hydrogen backbone would need to be expanded in the period up to 2040 compared to the initial hydrogen network in 2030. To provide insight into the measures required to integrate hydrogen supply into the grid at the landing zones, it was examined at what point in time the connecting pipelines from the landing zone to the backbone would no longer be sufficient. A connecting pipeline is a pipeline that, in this case, is capable of transporting hydrogen from the landing point or electrolysis plant on the coast to the hydrogen backbone. Many of these connecting pipelines are new pipelines. The diameter of the connecting pipelines from Maasvlakte and Eemshaven are now known. A

24” pipeline has been chosen for both connecting pipelines. This diameter is based on current knowledge of hydrogen demand and supply, including potential future growth. No decisions have yet been made regarding the required pipeline diameter for the other landing zones. Options are being investigated.

Specifically regarding Den Helder, this study assumes landing will take place in Middenmeer, around 20 kilometres south east of Den Helder. This location is close to the Gasunie Wieringermeer site on the hydrogen backbone. The model therefore does not include a connecting pipeline.

In most scenarios, the connecting pipe at Maasvlakte is sufficiently large to transport hydrogen flows to the backbone. The exception is the International scenario, which assumes a large amount of imported hydrogen. If this International scenario, as described in this study, becomes a reality, the chosen size of connecting pipeline from Maasvlakte will be insufficient. This is as expected, given the criteria for the construction of the pipeline. If it becomes clear between now and 2040 that hydrogen supply from Maasvlakte will develop as assumed in the International scenario in this study, there are probably options to add existing infrastructure to the hydrogen network. If the transport situation in the gas network (methane) does not allow this, an additional new pipeline could be constructed.

With regard to the connecting pipeline from Eemshaven, the maximum entry capacities assumed for the National and International scenarios exceed the capacity of the planned connecting pipeline. This is also in line with expectations, and there may also be options here to add existing infrastructure. If this is not possible, an additional pipeline will be constructed.

Figure 51 shows the sections (pale orange lines) and compression locations (pale orange dots) that may need to be reinforced in the period up to 2040, according to the scenarios and variations assessed. As previously noted, the required reinforcements are dominated by the output capacity of the storage facilities in the scenarios and variants.

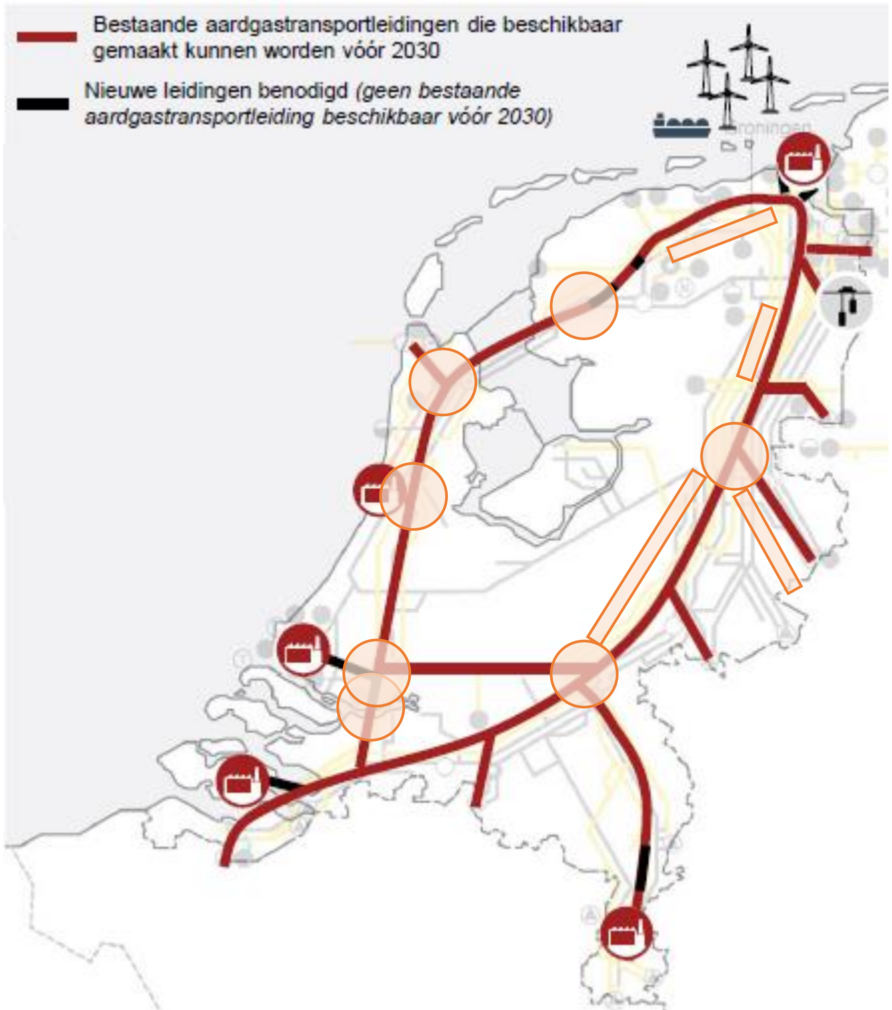


Figure 51: Sections and compression locations in the planned hydrogen network that may require reinforcement.

This is also why reinforcements can be seen on sections on the eastern side of the network. In order to be able to transport hydrogen from the north and east to the rest of the country in 2040, more transport capacity is needed than currently planned for the construction of the hydrogen backbone in 2030. In this eastern part of the Netherlands in particular, there are already many gas transmission pipelines that may no longer be needed for gas supply in the future, making it more likely a pipeline will be available for hydrogen transmission in good time. The scale of reinforcements required depends on the scenario and variants. A connection to the Epe caverns will also needed, if they become a hydrogen storage location in the future.

In addition to adding parallel pipelines on some sections of the hydrogen backbone, there will be a need for compression in the hydrogen network in the period up to 2040, based on the assessed scenarios and variants. Existing compression locations are suitable for compression in the hydrogen network. However, the compressors themselves will need to be replaced as natural gas compressors are unsuitable for the hydrogen compression. The compression capacity required depends on the scenario and variants.

As previously mentioned, the high output capacities of the storage facilities are due to hydrogen demand from electricity-generating plants. These hydrogen power plants provide a large part of the required flexibility for the largely renewable electricity system, by meeting demand for electricity in the occasional instance that no supply is available from sun and wind. We see that some of these hydrogen power plants are only used for a limited part of the year. As this study focuses mainly on the development of offshore and onshore transmission infrastructure, the cost efficiency of this type of limited peak deployment has not been analysed. It would seem appropriate to carry out further research in this area, which could also look at other forms of flexibility.

A potential solution is to install electricity-generating plants next to storage locations/facilities. This study assumes hydrogen power plants will be sited at existing electricity-generating plants. Hydrogen power plant placement could potentially be optimised to limit impact on the hydrogen network. The extent to which the electricity grid supports this should be investigated. Hydrogen power plants mainly produce a supply when there is little to no electricity production from sun and wind. The load on the electricity grid is not as high at these times, and there is therefore a reasonable degree of freedom to position hydrogen power plants closer to storage facilities. The load placed on the hydrogen backbone by hydrogen transport to the plants is therefore lower. An alternative solution is to examine the extent to which decentralised storage (next to power plants, for example by converting hydrogen into ammonia) is possible, to limit peak demand to storage locations and facilities.

The storage facilities will of course also need to be filled, and measures in the hydrogen network to allow the filling of the storage facilities (Zuidwending and Epe) have therefore been explored. Figure 52 shows the minimum and maximum exit capacities (from the hydrogen network to the regions) for the different scenarios and variants. In contrast to output from the storage facilities (entry capacities), it can be seen that filling capacities of the storage facilities do not dominate exit capacity in the other regions.

However, the storage facilities cannot be filled without measures in every scenario: compression capacity is needed in a number of locations in the west of the Netherlands and in Friesland, to ensure that hydrogen can be transport from the west to the east of the country. Nevertheless, required compression capacity is many times smaller than the capacity required to transport the maximum output capacity from the storage facilities.

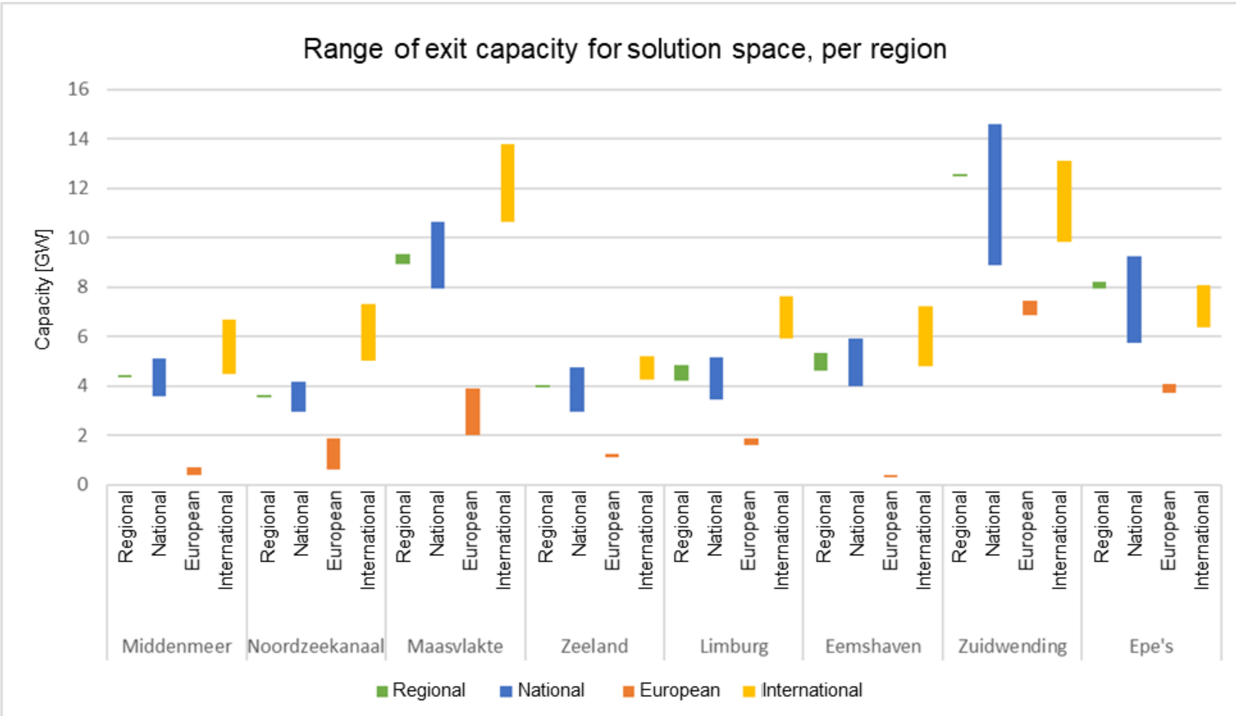


Figure 52: Distribution of exit capacity across all solutions per region for the planned hydrogen network.

6.4 Sensitivity analysis

The assumptions and results of the modelling focus on 2040, which creates a considerable amount of uncertainty in terms of technological and economic developments. A sensitivity analysis was therefore carried out for the key aspects.

6.4.1 Hydrogen import price

The hydrogen import price has an impact on the cost-optimised capacity of onshore electrolysis. A higher hydrogen price means an electrolyser can operate at break-even at a lower number of full-load hours, with the added effect that smaller surpluses from renewable energy sources can be used and less curtailment is needed. Two prices were applied to hydrogen imports during the modelling: €1.90 for the European and International scenarios (and the International + additional offshore wind energy variant), and €2.58 for the Regional and National scenarios (and the National + accelerated electrification variant). See Break-out 3 in section 5.7 for a detailed calculation.

The National scenario was used for the sensitivity analysis, which involves 10.4 GW of installed electrolysis capacity to prevent congestion. The hydrogen price of €1.00-2.50/kg is varied in increments of €0.50/kg. For the sensitivity analysis, installed onshore electrolysis capacity (outcome of the optimisation), optimised electrolysis capacity full-load hours, amount of curtailment (both peak capacity and total volume), and the volume of imported hydrogen are plotted against the hydrogen price.

Figure 53 shows that installed electrolysis capacity goes up as the price of imported hydrogen goes up. Greatest sensitivity lies in the region €1.00-1.50/kg. The increase flattens out above €2.00/kg. The amount of electrolysis to prevent congestion does not change across the price variations, because energy supply remains the same.

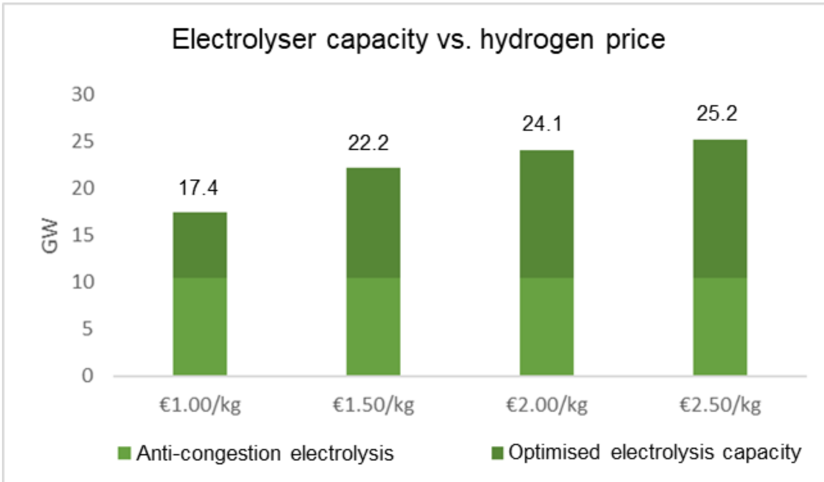


Figure 53: Sensitivity of electrolyser capacity to hydrogen import price

Figure 54 shows the full-load hours required for optimised electrolysis capacity goes down as the hydrogen price goes up. Here, too, we can see the greatest sensitivity lies in the €1.00-1.50/kg region with the decrease flattening out above €2.00/kg. The full-load hours of the electrolyser for congestion prevention are not shown, as the full-load hours are constant across the price variations.

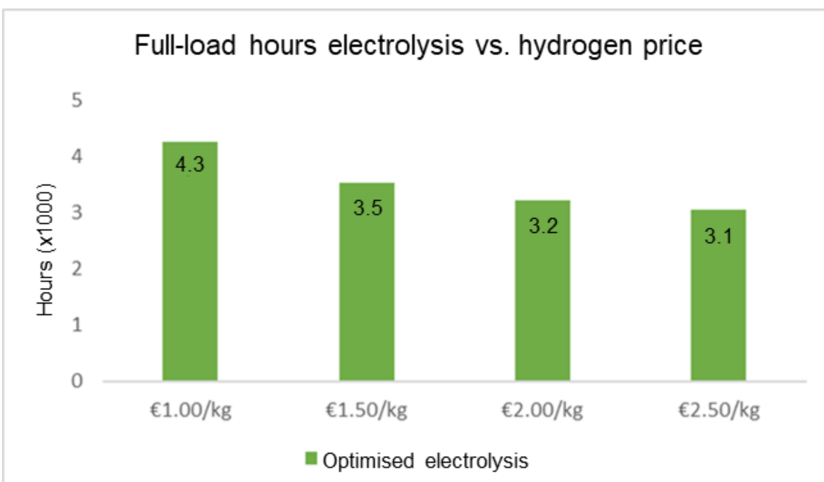


Figure 54: Sensitivity of electrolyser full-load hours to hydrogen import price

Figure 55 shows the amount of curtailment goes down as the hydrogen price goes up. This applies to a lesser extent for peak capacity and to a greater extent for volume curtailment, whereby the percentage of renewable energy lost to curtailment decreases. The largest decrease occurs between €1.00-1.50/kg, with peak capacity curtailment levelling off after €1.50/kg, while the decrease continues after €1.50/kg for volume curtailment.

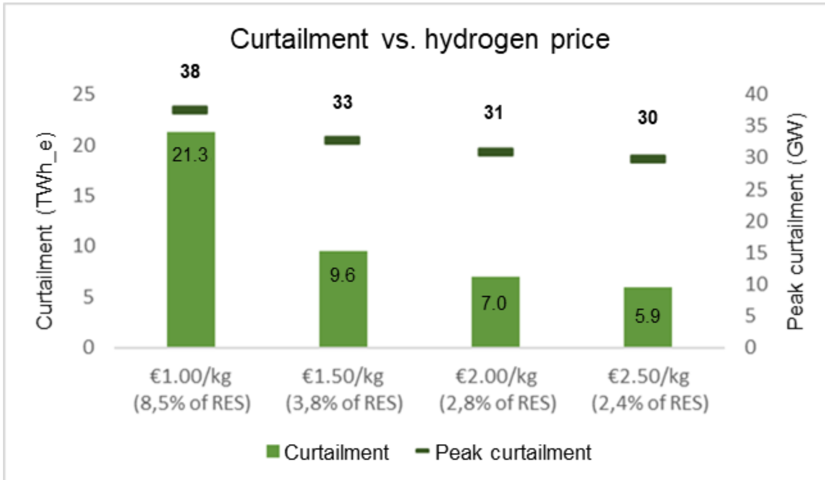


Figure 55: Sensitivity of curtailment (peak, volume, and % of RES) to hydrogen import price

Figure 56 shows the amount of imported hydrogen goes down as the hydrogen price goes up. Here, too, greatest sensitivity lies between €1.00-1.50/kg, above which the decrease is almost stagnant.

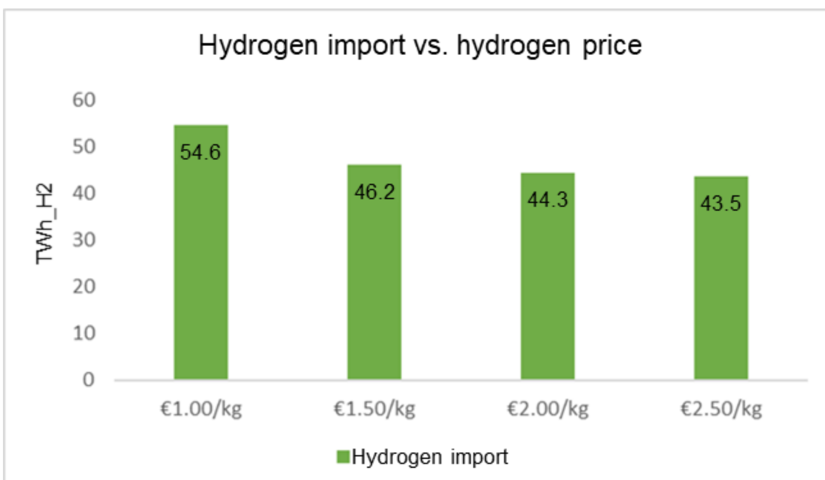


Figure 56: Sensitivity of hydrogen import volume to hydrogen import price

6.4.2 Price of electricity for onshore electrolysis

The modelling assumes that onshore electrolysis only uses surpluses in renewable energy supply. However, these electricity surpluses also have a price, which must be included in the domestically produced hydrogen price. A higher electricity price for these surpluses means that an electrolyser needs to operate for more full-load hours to break even. The modelling uses a price of €10/MWh for this surplus electricity.

The sensitivity analysis uses the International scenario, which is based on a hydrogen price of €1.47/kg and 3.3 GW of installed electrolysis capacity to prevent congestion, and the price of electricity for the purpose of onshore electrolysis varies in increments of €5 from zero to €20/MWh. For the sensitivity analysis, installed onshore electrolysis capacity (outcome of the optimisation), optimised electrolysis capacity full-load hours, the amount of curtailment (both peak capacity and total volume), and the volume of imported hydrogen is plotted against the price of electricity surpluses.

Figure 57 shows installed electrolysis capacity goes down as the price of electricity surpluses from renewable energy goes up. Greatest sensitivity lies in the €15-20/MWh range. The amount of electrolysis to prevent congestion does not change across the price variations, because energy supply remains the same.

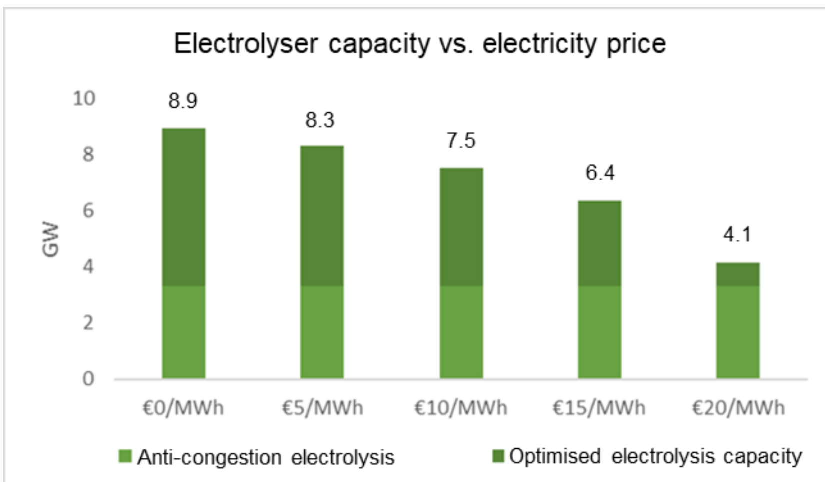


Figure 57: Sensitivity of electrolyser capacity to the price of electricity surpluses

Figure 58 shows the full-load hours required for optimised electrolysis capacity goes up as the price for electricity surpluses from renewable energy increases. Here, too, we can see greatest sensitivity lies between €15 and €20/MWh. The full-load hours of the electrolyser for congestion prevention are not shown, as they are constant across the price variations.

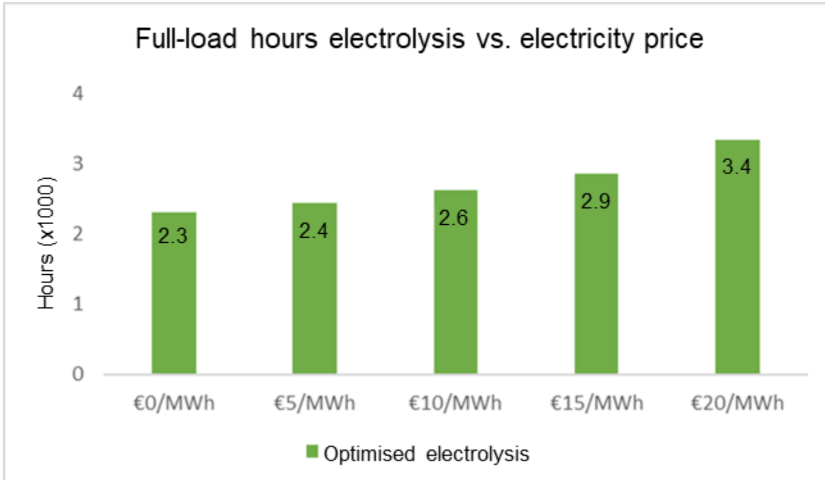


Figure 58: Sensitivity of electrolyser full-load hours to the price of electricity surpluses

Figure 59 shows the amount of curtailment increases as the price of electricity surpluses from renewable energy increases. This applies to a lesser extent for peak capacity and to a greater extent for volume curtailment, whereby the percentage of renewable energy lost to curtailment increases. The largest increase lies between €15 and €20/MWh.

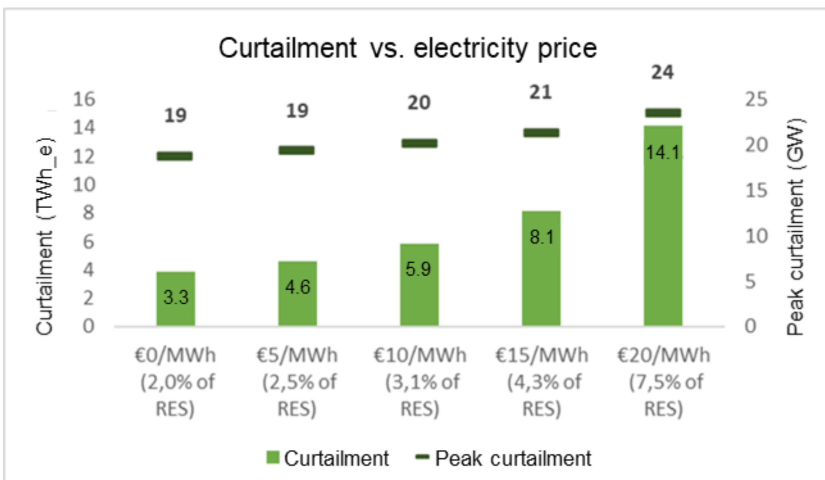


Figure 59: Sensitivity of curtailment (peak, volume, and % of RES) to the price of electricity surpluses

Figure 60 shows the amount of imported hydrogen goes up as the price of electricity surpluses from renewable energy increases. Here, too, greatest sensitivity lies between €15 and €20/MWh.

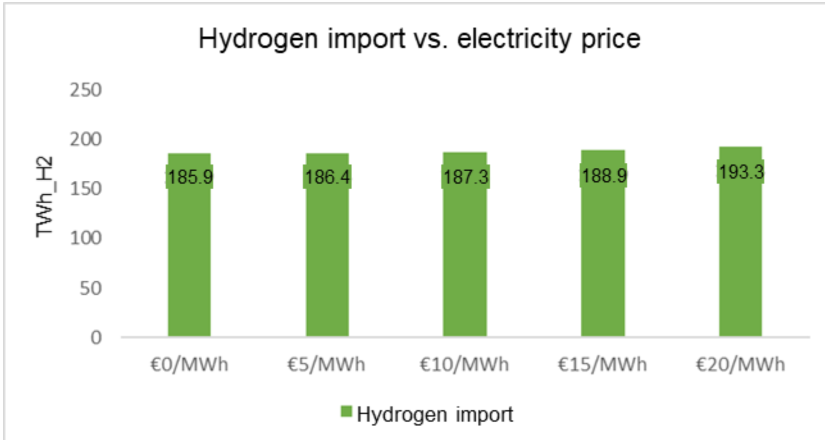


Figure 60: Sensitivity of hydrogen import volume to the price of electricity surpluses

6.4.3 Electrolyser costs in the target year 2040

Electrolyser costs (both CAPEX and OPEX) have an impact on an electrolyser's break-even point, which is evident from the full-load hours required in order to compete with the price of imported hydrogen. A higher CAPEX generally means the price of domestically produced hydrogen is higher, and the electrolyser will need to operate for more full-load hours to compete with imported hydrogen. In the modelling, electrolyser CAPEX also has an impact on the price of imported hydrogen, according to the rationale that the cost of the electrolyser itself will not differ significantly worldwide. For the purpose of this sensitivity analysis, the price of imported hydrogen was set at €2.15/kg in order to only test the direct sensitivity of electrolyser CAPEX. The standard value for electrolyser CAPEX in the modelling is €300/kW, with OPEX at 3% of CAPEX.

The sensitivity analysis uses the National scenario, with 10.4 GW of installed electrolysis capacity to prevent congestion, and the price of electricity for the purpose of onshore electrolysis is varied in increments of €100 between €200 and €500/MWh. For the sensitivity analysis, installed onshore electrolysis capacity (outcome of the optimisation), optimised electrolysis capacity full-load hours, the amount of curtailment (both peak capacity and total volume), and volume of imported hydrogen is plotted against electrolyser CAPEX.

Figure 61 shows installed electrolysis capacity reduces as electrolyser CAPEX increases. Sensitivity is almost linear in relation to electrolyser CAPEX. The amount of electrolysis to prevent congestion does not change across the price variations, because energy supply remains the same.

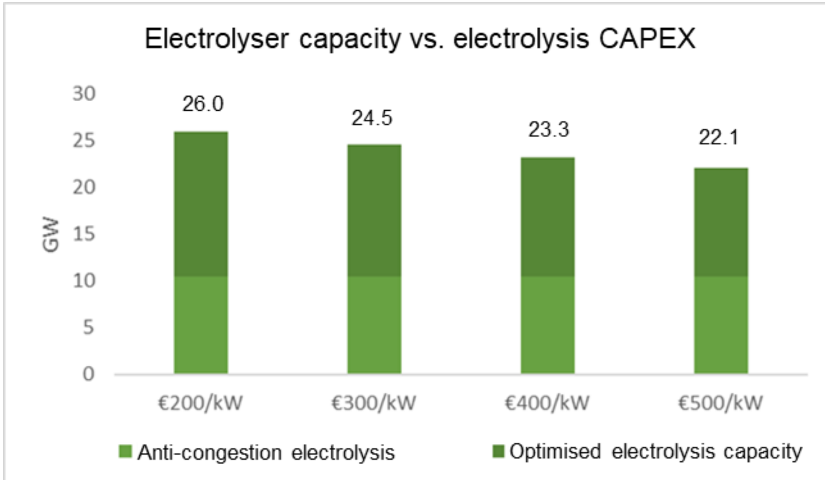


Figure 61: Sensitivity of electrolyser capacity to electrolyser CAPEX

Figure 62 shows the full-load hours required for optimised electrolysis capacity goes up as CAPEX for electrolysers increases. Sensitivity is almost linear in relation to electrolyser CAPEX. Full-load hours of the electrolyser for congestion prevention are not shown, as they are not dependent on price variations.

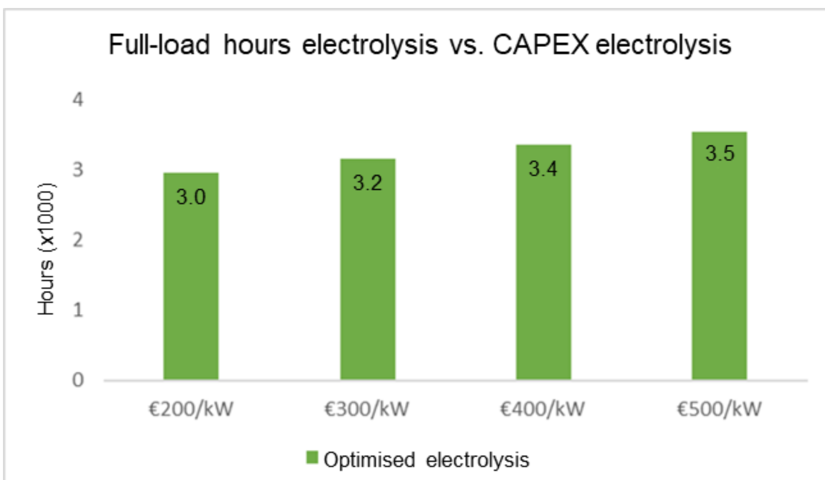


Figure 62: Sensitivity of electrolyser full-load hours to electrolyser CAPEX

Figure 63 shows the amount of curtailment goes up as electrolyser CAPEX increases. This applies to a lesser extent for peak capacity and to a greater extent for volume curtailment, whereby the percentage of renewable energy lost to curtailment increases. Sensitivity is almost linear in relation to electrolyser CAPEX.

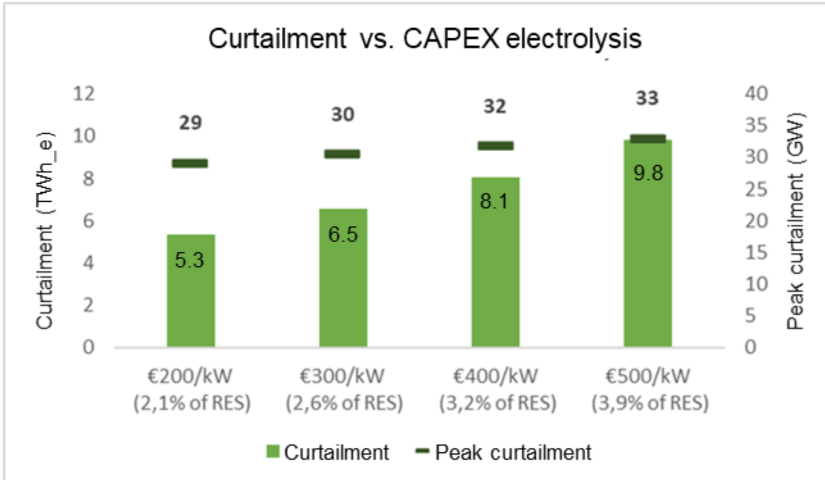


Figure 63: Sensitivity of curtailment (peak, volume, and % of RES) to electrolyser CAPEX

Figure 64 shows the amount of imported hydrogen goes up as electrolyser CAPEX goes up. Here, too, sensitivity is almost linear in relation to electrolyser CAPEX.

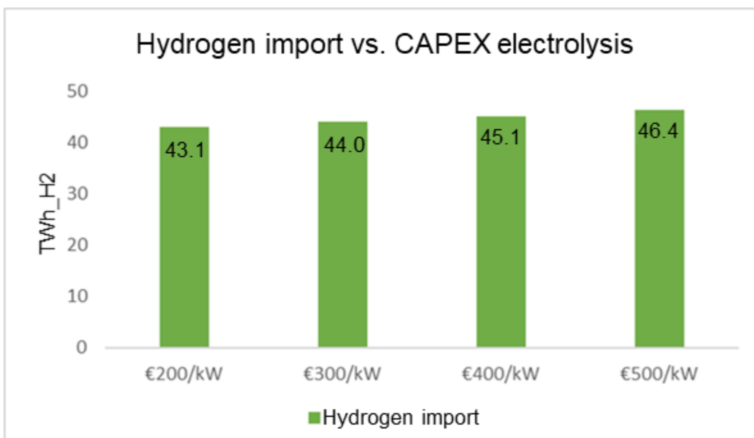


Figure 64: Sensitivity of hydrogen import volume to electrolyser CAPEX

6.4.4 Costs and benefits of electrolysis integrated into wind turbines

The cost implications of electrolysis integrated into wind turbines, relative to centralised offshore electrolysis, are outlined below.

Component level: Electrolyser component costs per MW will not differ significantly from those for centralised electrolysis. However, there are development costs associated with integrating the systems into wind turbines. Unlike centralised electrolysis, there also needs to be a supply of demineralised water. The associated costs depend on the chosen concept: centralised desalination and supply to individual wind turbines through pipelines, or integration of desalination modules in the turbine. The cost advantages of one-off, large-scale, centralised desalination are partly offset against the costs of pipelines to turbines. Integrating electrolysis into a wind turbine reduces the number of electricity conversion steps in the turbine and in the chain. When wind energy is fed as electricity, AC/DC and DC/AC conversion steps take place within the turbine. The latter can be avoided in a wind turbine with integrated electrolysis, since electrolysis is powered by DC.

Infrastructure: The difference in infrastructure between centralised and decentralised (integrated) electrolysis lies in a conversion step (see component level) and the method of energy release. A wind farm with centralised electrolysis uses inter-array cables between the wind farm and a central island, platform, or cluster of platforms where electrolysis takes place; in the case of decentralised electrolysis, turbines are connected to a compression platform by pipelines. In both concepts, there is a main pipeline that brings hydrogen to land.

Integrated electrolysis does not require an island for the installation of electrolysis capacity, but it does require compression stations instead. For a configuration with 12 GW of electrolysis capacity, this can reduce costs by up to €300 million/year. The wind farm's energy landing infrastructure (pipelines and cables) will also be less expensive. For 12 GW of integrated electrolysis, these costs are up to €50 million/year lower than for centralised electrolysis.

Operational advantages: Avoiding a DC/AC and an AC/DC step and replacing inter-array cables with pipelines reduces electrical losses in the chain. It was mentioned during the market consultation that for decentralised electrolysis, electrical losses are reduced by up to 10%.

Wind farm optimisation: offshore wind farms that supply energy as electricity are optimised in terms of electrical infrastructure. This also applies to wind farms with centralised hydrogen production. For a wind farm with decentralised electrolysis integrated into wind turbines, optimisation of the design (rotor diameter to generator ratio) and wind farm layout is possible.

6.4.5 Comparison of hydrogen production and hydrogen import costs

The future market price of green hydrogen is uncertain. The import price may determine prices in the target year 2040. If so, the business case for domestic green hydrogen production has an unprofitable component.

The cost level comparison provides a first indication of the competitiveness of domestic green hydrogen production.

The hydrogen cost level is expressed as a Levelised Cost of Hydrogen (LCoH) in €/kg. LCoH comprises the following components:

- Electrolyser CAPEX and OPEX;
- Electricity price;
- Number of full-load hours, which determines total volume of hydrogen generated;
- Capital costs.

Electricity price and number of full-load hours depend on the operating mode, which leads to differences in the LCoH.

For surplus-based operation, this study assumes an electricity price of €10/MWh. For electrolysis coupled to an offshore wind farm and for electrolysis to prevent congestion (anti-grid congestion), we assumed €35/MWh. This is an assumption in relation to wind farms' Levelised Cost of Electricity (LCoE) in the target year 2040. The costs of the offshore grid connection have also been included for coupled electrolysis. If wind farm developers are required to bear offshore grid costs, the LCoE for the wind farm increases. By way of an indication, costs associated with a 2 GW HVDC connection in search area 1 have been translated into a contribution towards LCoE of +€16/MWh. Adding this cost to the assumed electricity price of €35/MWh means LCoH goes up by €0.7/kg. The number of full-load hours for the electrolysis operating modes follows from the analyses. The same steps as described in Break-out 3 in section 5.7 have been used to calculate the LCoH. Table 19 shows the results of the calculation.

Table 19: Levelised cost of hydrogen for different types of electrolysis

Electrolysis variant	E-price [€/MWh]	Full-load hours [h/yr]	LCoH (including offshore grid costs) [€/kg]	LCoH (excluding offshore grid costs) [€/kg]
Flexible dispatch	10	2500–3000	1.7–1.8	1.0–1.1
Coupled to offshore wind	35	4500–5000	2.6–2.7	1.9–2.0
Anti-congestion	35	2500–4000	2.7–3.0	2.0–2.3

The costs of the offshore electricity grid (the connection from offshore wind farms to land) are currently socialised through energy rates. If, as in the case of coupled electrolysis, there is a direct connection between an offshore wind farm and a user and the electricity is not fed into the high-voltage grid, the costs of the connection should not be socialised. It is therefore advisable to make a distinction in the offshore infrastructure funding policy framework between a direct connection and a grid.

The hydrogen import price in this study varies between €1.9 and €2.6/kg, depending on the scenario. The following conclusions can be drawn on the basis of this analysis:

- Electrolysis based on surpluses: there is a substantial margin relative to the lower limit of the hydrogen import price. If there is sufficient competition between electrolysis operators, willingness to pay could be higher than the assumed €10/kg.
- Coupled to offshore wind energy (without a connection to the national electricity grid): LCoH is around the lower limit of the hydrogen import price. If these assumptions become a reality, this could result in an unprofitable component for electrolysis coupled to offshore wind energy compared to imports.
- Anti-grid congestion: LCoH is just above the lower limit of the hydrogen import price. The risk of an unprofitable component therefore also exists for this type of electrolysis.

For the scenario involving electrolysis coupled to offshore wind energy, the resulting LCoH is €2.7/kg and thus higher than the upper limit of the import price. Adding the costs associated with the offshore grid to a wind farm's business case makes an unprofitable component for coupled electrolysis more likely.

7 Conclusions and discussion

7.1 Conclusions

A large amount of offshore wind capacity can be integrated by taking a coordinated approach to landing electricity.

By taking a coordinated approach to landing electricity (taking into account available space in the onshore electricity grid), the energy from 31 GW of offshore wind can be integrated into the high-voltage grid planned for 2035 without major problems. A number of bottlenecks are anticipated if electricity from 38.5 GW of offshore wind is to be integrated, for which a potential expansion of the high-voltage network up to 2040 appears to be possible and is, to a certain extent, already provided for in TenneT's 2022 Investment Plan. Nevertheless, large-scale conversion of surpluses to hydrogen is anticipated in every scenario, as there is not always sufficient final demand for electricity, but there is sufficient demand for green hydrogen. This study analysed a number of varying approaches to the landing of electricity, in which landings were based on:

- The maximum capacities in the search areas;
- The expected timeline for the realisation of wind farms in the search areas;
- Distance to the landing zones;
- The potential timeline for the reinforcement of various electricity routes;
- Demand for electricity in the coastal regions; and
- An estimate of the maximum electricity feed-in to the onshore grid at the landing zones.

This study did not look at spatial and environmental impact issues affecting the routes and landing zones.

Distribution of the electricity landing zones mainly affects electricity grid congestion. Landing significant capacity in Eemshaven (7.2 GW) and therefore relieving burden on Maasvlakte (8.7 GW) makes it possible to land electricity from 31 GW of offshore wind without significant congestion. In the case of 38.5 GW total offshore wind capacity, the right distribution (Eemshaven 10.5 GW, Maasvlakte 8.7 GW) can also help reduce grid congestion significantly. However, in the 38.5 GW scenario, congestion cannot be entirely resolved by redistribution alone. Remaining bottlenecks will need to be resolved through other measures. The estimated cost of an operational solution is at least €30 million per year.

As a variant, feeding in 2 GW of offshore wind in Graetheide (high-voltage substation in Chemelot, Limburg) was analysed with the aim of alleviating congestion in North Brabant. This reduces congestion, which in turn considerably reduces required operating costs. It is not clear whether this solution can avoid investments in the high-voltage grid in the longer term, however it can at least postpone them.

The different landings require different overall cable lengths, resulting in different costs. For the 38.5 GW scenario, redistribution to create greater capacity at Eemshaven reduces HVDC cable length by -320km and cuts overall infrastructure costs by 2%. Given this limited difference in offshore infrastructure costs, other considerations may be more important when comparing these two landing configurations.

In addition to a coordinated approach to the landing electricity, electrolysis is used in all scenarios to use green energy surpluses for hydrogen production, ranging between 8 and 23 GW. Without this electrolysis capacity, substantial curtailment would need to be applied to balance the system, and more hydrogen would need to be imported.

There is sufficient green energy and demand for hydrogen to warrant substantial electrolysis capacity. Alternative operating modes help to reduce grid congestion.

Three electrolysis operating modes were analysed for the purpose of maintaining balance in the system[46]:

1. Electrolysis based on green energy surpluses (*electrolysis in the event of surpluses)*
2. Electrolysis that tracks the profile of a wind farm (*coupled electrolysis*)
3. Electrolysis capacity that is activated when a feed-in limit is exceeded (*anti-congestion electrolysis*)

Electrolysis in the event of surpluses: Optimum electrolysis capacity in the event of surpluses has been determined for all scenarios. The large supply of green energy means it is possible to achieve significant capacity with a large number of full-load hours (2500–3200 hours) that is only activated in the event of surpluses. This electrolysis capacity and its use competes with the import of hydrogen.

The optimised electrolysis capacity for the International and European scenarios with 31 GW of offshore wind energy is around 8 GW, whereas the optimum capacity for the Regional scenario is 20 GW. This difference is due to the major differences in electricity production from solar PV and onshore wind (around 60 TWh for the International and European scenarios, and around 120 TWh for the Regional scenario). The optimised capacity for the National scenario with 38.5 GW of offshore wind energy is 23 GW. The other determining factor is the hydrogen import price, which is lower in the International and European scenarios than in the Regional and National scenarios.

The upper end of the range implies a steep increase in electrolysis capacity to 23 GW in 2040, up from just 3 to 4 GW in 2030 under the Climate Agreement.

Electrolysis coupled to offshore wind energy: One of the potential solutions for integration of offshore wind energy is to add electrolysis capacity that tracks an offshore wind farm's production profile. Using this type of electrolysis means that some offshore wind energy is kept out of the electricity grid and instead converted directly into hydrogen.

The addition of coupled electrolysis increases total electrolysis capacity by around 1 to 2 GW, compared to the situation without coupled electrolysis.

[46] Current Dutch and European energy laws and regulations would probably apply to coupled and anti-congestion forms of electrolysis, as these forms disrupt the free market function.

Adding coupled electrolysis, with capacities based on the grid feed-in limits for each landing point, reduces grid congestion in coastal areas. Grid congestion continues to exist further inland on the Tilburg-Eindhoven-Maasbracht and Hengelo-Zwolle routes.

Hydrogen demand for the purpose of electricity production in hydrogen power plants increases by 10 TWh_{H2}, as electrolysis is also used when there is no surplus green electricity. There is a reduction in both curtailment of electricity generation and import of hydrogen.

<u>Anti-congestion electrolysis</u>: In this mode, electrolysis is applied when feed-in limits are exceeded. The grid congestion results are similar to the situation involving coupled electrolysis. The difference is that in this case, more electricity from offshore wind is fed into the grid, resulting in less use of dispatchable capacity and higher net export of electricity.

Offshore electrolysis is expected to mature in time to play a role in the integration of offshore wind energy into the energy system in the 2030s. Large-scale offshore electrolysis can offer a cost advantage over coupled onshore electrolysis.

Based on interviews with electrolyser suppliers, wind turbine manufacturers, and electrolysis project initiators, we conclude that offshore electrolysis is expected to be ready for large-scale application in the early 2030s. Search areas 6 and 7 are suitable for the application of large-scale offshore electrolysis, in view of their distance to the coast and the size of the areas. For the National scenario with 38.5 GW of offshore wind energy, it is assumed 12 GW of offshore electrolysis will be applied. The costs are based on an energy island with installed electrolysis and compression and transport of hydrogen to land through a pipeline.

The main cost differences between the solution with electrolysis on an island and the solution with coupled onshore electrolysis are:

- Costs of offshore infrastructure: reduction of €460 million per year
- Costs of compression: increase of €85 million per year
- Costs of (less) hydrogen imports: reduction of €300 million per year
- Costs of electrolysis: increase of €70 million per year
- Costs of electricity import: increase of €30 million per year

In conclusion, the use of large-scale offshore electrolysis in areas 6 and 7 offers considerable cost advantages in this situation compared to the solution with coupled onshore electrolysis. On the basis of this analysis, platform-based centralised electrolysis does not appear to offer any cost advantages.

A brief analysis shows the addition of an electricity connection to this energy island can yield additional benefits (+€75 million per year). In this specific case, a 3 GW HVDC connection is optimal. The capacity of this connection is largely determined by the level and profile of the green energy shortages. Based on the analysis, we conclude there is no set optimum ratio between the capacities of the electricity and hydrogen connections in this type of hybrid system.

Landing offshore wind energy and the associated electrolysis does not determine the capacity of the future hydrogen network; the use of hydrogen power plants is the dominant factor.

The analysis of the hydrogen network shows that regardless of the distribution of offshore wind energy landing, and the associated distribution of installed electrolysis capacity, the planned hydrogen network needs to be expanded to allow processing of the hydrogen flows to be fed in.

Transport from the offshore wind landing zones and the associated electrolysis does not determine the transport capacity required for the future hydrogen network. The dominant factor determining the scale of the hydrogen network is transport from storage locations to hydrogen power plants for the generation of electricity during shortages in the electricity supply from renewable sources.

This transport capacity can be achieved with the help of additional transmission pipelines and compression. Large hydrogen surpluses, which need to be stored in storage facilities, also require expansions of the hydrogen network in the form of both compression and additional pipelines. However, required compression capacity is much lower than needed for transmission from the storage facilities.

Existing natural gas pipelines can potentially be switched to hydrogen to meet this additional need for transport capacity in 2040. This approach is similar to the way in which the hydrogen backbone will initially be developed.

The balance between electricity supply and demand is characterised by many hours of green energy surpluses. Electrolysis creates additional demand, reducing electricity surpluses.

Integration of 31 GW or 38.5 GW of offshore wind energy into the Dutch energy system has major implications for the balance between electricity supply and demand. Times at which renewable electricity production exceeds current demand necessitate the use of flexibility tools such as export, batteries, and electrolysis to eliminate the surplus. Even after the use of export as a flexibility tool, there are still many hours a year in which the supply of renewable electricity exceeds demand. In the International scenario with 31 GW of offshore wind energy, around 3000 hours of surpluses occur. The total surplus is more than 25 TWh_E; around 11% of annual demand. In the National scenario with 38.5 GW of offshore wind energy, surpluses occur in around 4600 hours. The overall surplus is more than 80 TWh_E; more than 35% of annual electricity demand. Hydrogen production by means of electrolysis creates additional demand, reducing the number of hours of surpluses.

Whether this domestic hydrogen production can compete with imports depends on the future hydrogen import price, the price of the electricity consumed, and whether offshore infrastructure costs are socialised. Based on the assumptions made, coupled and anti-grid congestion electrolysis carry the risk of an unprofitable component relative to the import price.

7.2 Discussion

This section looks at a number of key assumptions and limitations in the study with the aim of informing the reader about the challenges involved in analysing the future of the energy system and how these challenges have been addressed in this study.

7.2.1 Demand and supply scenarios

The development of supply and demand was estimated for all energy carriers and sectors in 2040, for each of the four basic scenarios, as a starting point for the model chain. Investment decisions are usually made on the basis of long-term prospects rather than a single target year. Another major limitation is that only one reference year was used for the calculation (2015).

This estimate was produced by means of interpolation between two input values, namely for the years 2030 and 2050. This approach has the following limitations:

- All grid companies have drawn up three scenarios for 2030 in the context of their 2022–2031 Investment Plans: the Climate Agreement scenario (resulting in a 45% reduction in CO_2), the International Ambition scenario (with a 46% reduction) and the National Target scenario (resulting in a 51% reduction). This means additional measures will be required before 2030 if a new government decides that, like Europe, it wants to achieve a 55% reduction by 2030. It is not yet known what these measures will be and/or whether a new government will aspire to a 55% reduction. One option is to accelerate development of offshore wind to reach a total installed capacity of around 20 GW by 2030. This study did not examine the impact of such an acceleration, however we anticipate the impact on the situation in 2040 would be low, given total installed capacity would not be increasing per se, but rather undergoing a shift in timing.
- The number of scenarios for 2040 was limited to the four basic scenarios that follow the narrative of II3050, mainly because calculating the effects of a scenario throughout the entire model chain is a time-consuming process, particularly as multiple iterations of this calculation are carried out. In addition, it becomes increasingly difficult to draw general conclusions if results vary widely. It was nevertheless decided to take two potential developments into account at this stage: electrification of industry (variant on the National scenario) and additional electrolysis based on additional offshore wind energy capacity in the International scenario (in other words, opting for greater self-sufficiency in a scenario with global ambition). The four basic scenarios and two variants cover a number of the key points. New insight in areas such as the role of nuclear energy may cause new key points to become relevant in the future, which can be explored in a future analysis.
- Developments sometimes move at a more rapid pace than currently predicted. For example, who would have predicted that solar and wind costs would have fallen by around 50% and over 90% respectively in 20 years? Such uncertainty plays a large role in determining the accuracy of our 2040 estimates, particularly when looking beyond a 10-year period. This is one of the reasons why our expert judgement estimates of the speed at which a development will take place in the period between 2030 and 2050 have been assessed by TNO, RVO, and PBL experts. An explicit choice was also made to work with ‘increments’ of 0.25 (range of 0-2, where 1 equals linear growth). Consequently, our estimate of demand and supply in 2040 is an educated guess that creates an initial picture of the four key points in 2040 and is also instrumental in enabling future grid impact analyses.
- Our expert judgement estimates are based on assumptions about technological developments and rising/falling prices for certain technologies (such as the EU-ETS price, which will mean grey

hydrogen is no longer able to compete with blue and green hydrogen by 2050). Whether the assumed price developments actually occur depends on available innovation budgets, developments in applicable law (e.g. whether international agreements on aviation and shipping are ambitious), and policy decisions.

- It is currently still uncertain how aviation and shipping will become more sustainable. Possible solutions include importing sustainable fuels and converting hydrogen in the Netherlands. In the second situation, additional demand for electricity, renewable or otherwise, needs to be taken into account due to conversion and potentially due to the use of Direct Air Capture. The ETM, as applied in this study, does not currently take this demand into account.

7.2.2 Offshore wind energy and infrastructure

Offshore wind

- This study did not seek to identify optimum offshore wind capacity. Neither did it analyse whether the future electricity market offers sufficient prospects for subsidy-free development of offshore wind. Such insight would require the application of market modelling and discussions with developers, investors, and the industrial clusters (the larger buyers).
- Wind profiles have been defined for the adopted reference year 2015 for electricity generation from offshore wind in various offshore locations. Wind energy yield can differ significantly from year to year. The reference year 2015 is an average year in terms of wind energy yield, which is a better starting point for the research questions in this study than assuming an extreme wind year.
- A standard wind farm production profile was used in the calculation, based on modern turbines and wake effects for a typical wind farm. Future developments may alter the eventual production profile. There is not yet a consensus on the impact clustering many wind turbines (for example 8 GW in search area 6) has on wake effects. As a result, total electricity generation and peak capacity of offshore wind may be lower.
- The same electrical losses and availability losses have been deducted from the gross wind farm production curves for the different wind farms. In practice, losses will vary between farms, and availability losses vary throughout the year. This could actually result in higher peak offshore wind capacity.

Offshore infrastructure

- The costs associated with an energy island are highly uncertain and based on the Danish cost-benefit analysis for the Danish energy island. In practice, costs depend on water depth and the wave climate at a specific location. A location-specific design can reduce this uncertainty.
- Offshore infrastructure could potentially be optimised further if offshore electrolysis is used. For example, a hybrid connection can be achieved by connecting an energy island in area 6 (electrically) to an HVDC platform in area 5. This can save money on an onshore HVDC converter

and HVDC cable length. It would also, for example, be possible to release area 3 on an island in area 6.

- Additional interconnection, particularly from offshore wind hubs, can have a significant impact on the results. Greater exchange with other countries could reduce the need for electrolysis and the use of hydrogen power plants, however this could result in a greater impact on the onshore grid.

7.2.3 Network analysis

Electricity grid congestion analysis

- For the purpose of this study, an estimate has been made of the planned grid model for 2035, which includes infrastructure expansions from the IP2020 that are still in the study phase. The precise details and commissioning date for these expansions in the study phase are still uncertain. There may also be other grid expansions realised which are not included in the grid model. A logical next step is to explore other grid reinforcements and their impact based on the production profiles in this study.
- The grid model for this study does not use a representation of the grid in other countries, which is indeed used for the Investment Plans. The power exchange between the UHV grid in the Netherlands and grids in other countries is modelled in the form of power injections (positive or negative for import and export respectively) at existing border connections. These injections are distributed proportionally (and based on capacity) between border connections per country. In reality, the exchange can vary greatly from one border connection to another. The situation in other countries also has a major impact on the load on the Dutch grid. For example, if there is a large amount of north-to-south transport in Germany, due to the input of large amounts of offshore wind energy in that country, this also increases the load on the Dutch connections from north to south[47]. More detailed modelling could identify additional congestion (particularly on the North–South connections), which could reduce the amount of additional offshore wind energy capacity in Eemshaven.
- Only N-1 calculations were carried out for this study[48]. It has therefore not been investigated whether there is scope for maintenance, whereby assets need to be taken out of service and the remaining grid still needs to be N-1 safe. This means, for a complete analysis, N-2 loads would also need to be investigated.

[47] For example: in the case of an hour in which 2 GW of energy is imported from Germany, this study distributes this energy between the four interconnectors, with 0.5 GW of energy imported per interconnector. In reality, 4 GW of energy could flow from Germany to the Netherlands in the north, while 2 GW of energy flows from the Netherlands back to Germany in the south: a ‘loop flow’.

[48] N-1 analysis means that the load on a component (for example a connection) is determined at the time that another component is unavailable

- The DC load flow is an estimate of the AC load flow, which provides a more accurate calculation as well as providing insight into any voltage issues. This has not been done in this study. More specialist studies (e.g. dynamic stability or harmonic studies) have also not been carried out.
- As offshore wind input mainly impacts the ultra-high-voltage grid (220–380 kV), this study only shows congestion on this grid. No research has been carried out into the potential impact on the high-voltage grid (110–150 kV).
- The calculated costs of redispatch, as mentioned in the report, are based on an assumption of €100/MWh. This is the cost assumption currently used in investment plans. How these costs will develop in the future is uncertain, although an increase is likely.
- This analysis does not carry out a quantitative assessment of reinforcing the onshore grid versus adjustments to landings or electrolysis capacity. Grid reinforcements could be a more cost-effective solution for some routes than introducing additional electrolysis capacity.

Modelling of United Kingdom wind connector

- This study assumes an additional operational interconnector between the Netherlands and the United Kingdom. This interconnector has a capacity of 2 GW and has been assumed to land in Maasvlakte. However, at the time of writing, this interconnector would most realistically be combined with a wind farm, in other words a wind connector. This means that one of the wind farms that lands in Maasvlakte is also connected to the United Kingdom. As a result, maximum input of this interconnector is 2 GW for import and wind energy combined. The grid calculations were carried out on the basis of a separate interconnector, which means that 2 GW can be injected from the interconnector as well as 2 GW from the wind farm.
- The largest overload occurs in hours when the maximum import is 3 GW (1 GW from the existing BritNed interconnector and 2 GW from the new interconnector) and a large amount of offshore wind energy is being landed. Given it is more realistic that this interconnector is in fact a wind connector, the loads on the connections around Maasvlakte are probably somewhat lower than reflected in the results.

Hydrogen network congestion analysis

- The timing for converting additional natural gas pipelines to hydrogen pipelines in the period up to 2040 is uncertain. However, it must be examined if demand for natural gas has fallen sufficiently to convert existing pipelines so that security of transport remains guaranteed. If this is possible, there will be no need to invest in the construction of new hydrogen pipelines.
- A large proportion of hydrogen power plant capacity is only used for a limited part of the year. As this study focuses mainly on the development of offshore and onshore transmission infrastructure, the cost efficiency of this type of limited peak deployment has not been analysed. It would seem appropriate to carry out further research in this area, which could also look at other forms of dispatchable electricity generation.

- In order to meet the calculated demand for hydrogen storage, including to maintain security of supply during a 'dunkelflaute[49]' period, dozens of new locations (e.g. salt caverns) need to be developed. The question of where and how this can be done in the Netherlands requires further research.

7.2.4 Electrolysis

- The electrolysis capacity optimisation calculation is based on a fixed merit order in the electricity and hydrogen markets. Optimised capacity is only used at times of surplus of renewable electricity (in this study: offshore and onshore wind and solar PV). A fixed price has been assumed for this electricity (€10/MWh). This analysis approach can be refined by applying an electricity market model, in which electrolysis can be included as a specific demand sector, with its own maximum price. This can result in more realistic operating behaviour.
- A steep cost reduction trajectory has been assumed for electrolysers. The current cost level for small-scale projects is over €1000/kW. For 2040, we assume €300/kW for onshore electrolysis. The impact of this assumption was taken into consideration in the sensitivity analysis. It is also advisable for follow-up studies to examine cost sensitivities when comparing different types of electrolysis, taking into account the uncertainty of future cost levels.
- The optimisation focuses primarily on the balance between import of hydrogen and national production in the form of surpluses. The future hydrogen import price is still highly uncertain, as also emphasised in the sensitivity analysis (chapter 6.4.1). A more in-depth analysis comparing anticipated availability of hydrogen for import, anticipated costs of different modes of import, and the combined import price with domestic forms of production, can give a more robust picture of optimum national electrolysis/hydrogen production capacity.
- Operating coupled electrolysis and anti-grid congestion electrolysis enables the integration of 38.5 GW. However, it is not possible to restrict the freedom of operation of the electrolysers in this way under the current regulatory framework. In addition, there are likely to be costs for market participants, as the electrolyser operator may be forced to buy electricity at a high price (or the wind farm operators are unable to sell their electricity on the market for a high price). This extra, non-market-driven demand raises the electricity price, which means more conventional generation methods are used elsewhere in the country (or there will be less demand). At system level, another way of using electrolysers (and the associated system costs) is therefore somewhat similar to the current operational solution to incidental congestion, namely redispatch. In practice, electrolysis operators will make decisions regarding hydrogen production based on electricity prices, the market price of hydrogen, and demand and/or availability of power/gas. This can lead to behaviour that differs from the modes modelled in this study.

[49] German term used for when little or no energy can be generated from renewables due to a lack of sun or wind.

- The solution involving 12 GW of offshore electrolysis shows this configuration can reduce congestion near to the landing zones. In this solution, offshore electrolysis capacity is based on the onshore feed-in limits. Congestion remains a structural problem further inland, however, that cannot be resolved by installing more offshore electrolysis capacity. Further optimisation of offshore electrolysis capacity could be an interesting follow-up analysis.

8 Implications

8.1 Offshore wind energy and infrastructure

- With the right distribution of offshore wind energy capacity across the landing zones, it is possible to integrate electricity from 31 GW offshore wind with limited grid congestion. Based on the grid model used, however, this requires significant landing in Eemshaven, which means crossing the Wadden Sea. As an alternative to concentrating electricity landings in the North, and in the event of further offshore wind expansion to 38.5 GW, further analysis is required on the extent to which additional grid reinforcements would increase the number of options. System costs and spatial planning aspects of alternatives would also need to be explicitly considered.
- In a climate-neutral energy system dominated by sources such as wind and solar PV, many hours of surplus electricity will be produced. This is inherent to the fact these sources are variable: installed capacity needs to be higher than peak demand. Ensuring significant electrolysis capacity reduces the number of hours of surplus. The question, however, is what price electrolysis operators pay for electricity and whether this offers sufficient income for future offshore wind farms. The value of the hydrogen produced is the guiding principle: the modelling of a future international hydrogen market (and insight into the value of each ‘colour’) can provide insight.
- Although costs associated with HVDC cables are substantial, the cost calculations show that the difference in cable length between the electricity landing configurations examined leads to a very small difference in costs. For this reason, it is recommended that other criteria are prioritised, when considering landing configurations.
- The infrastructure cost advantages of offshore electrolysis over coupled onshore electrolysis are potentially significant, particularly when implemented on a large scale. In the coming years, market participants expect to be able to better estimate how the variants relate to each other. To achieve economies of scale, further research into the possibilities of centralised and integrated electrolysis in search areas 6 and 7 is recommended. However, to ensure an effective contribution to the energy system, there must be a prospect of sufficient demand for green hydrogen and sufficient generation of renewable electricity. It must be considered that creating an energy island will require a long lead time; it is therefore advisable to take this decision in good time (around 10 years before the start of the operating phase of the first connected wind farms).

8.2 Implications for onshore infrastructure

- The choice of a specific offshore wind energy capacity target for a specific year (for example 38.5 GW in 2040) and the landing zones has a major impact on the required capacity of onshore infrastructure. Timely and consistent policy will help ensure the timely delivery of the required onshore infrastructure. Significant changes in the offshore wind capacity can mean that grid reinforcements that have already been planned or carried out become over- or under-dimensioned. In many cases, the timely completion of expansion projects for the high-voltage

network, which are currently in the study phase, is a precondition for the ability to connect large amounts of offshore wind energy to the electricity grid.
- The planned additional grid reinforcements place heavy demands on grid companies. Key challenges include long permit processes and availability of personnel.
- A high offshore wind energy capacity, combined with high installed onshore electrolyser capacity, changes the economic playing field within the energy market, and therefore also the anticipated energy flows. Larger peaks and troughs will change the burden on the grid. This study shows the right location and the right operating behaviour for electrolysis can help reduce congestion. The right incentives need to be introduced for this purpose, which can take various forms. Further research to identify potentially effective incentives and to assess how they relate to the current legal framework is recommended.
- A timely decision needs to be taken on the role of hydrogen in the Netherlands' energy supply. A high degree of electrification requires a different approach to onshore infrastructure (for electricity, methane, and hydrogen) than a policy that focuses on a large demand for hydrogen. The long lead times for infrastructure projects mean a decision is needed to guarantee that future offshore wind projects are in line with requirements.
- The location of large (closed cycle) electricity-generating power plants that run on hydrogen in this study is based on the locations of current gas-fired power plants[50], which can create a peak demand for transport capacity in the hydrogen network. There are various solutions to this problem: locating these power plants nearer to the storage locations, greater conversion of gas grids to hydrogen transport capacity, and/or alternative supply and storage (for example from industry with flexibility options, or hydrogen import locations). It is recommended that these options are explored in further detail.

8.3 Implications for electrolysis

- Electrolysis needs the right investment signals and operating signals to effectively reduce grid congestion. However, it is not currently possible to restrict the freedom of operation of electrolysers under the current regulatory framework (specifically non-discriminatory access to the electricity grid). In addition, there are likely to be costs for market participants, as electrolyser operators may be forced to but electricity at a high price (or the wind farms are unable to sell their electricity on the market for a high price). This extra, non-market-driven demand raises the electricity price, which means more conventional generation methods are used elsewhere in the country (or there will be less demand). At system level, another way of using electrolysers (and the associated system costs) is therefore somewhat similar to the current operational solution to incidental congestion, namely redispatch.
- For both centralised and integrated offshore electrolysis, these configurations are expected to be technically feasible in the early 2030s. There is no consensus yet as to which method is the most cost-effective, due to the early stage of development of these solutions; this will also

[50] Smaller open cycle hydrogen power plants are distributed across the grid in proportion to peak deficits.

ultimately depend on the specific project (for example wind farm size, distance from the coast, depth, and wave climate). It is therefore wise, for the time being, to consider both variants in the roll-out of offshore wind energy.

- Market participants consider policy to be a driving force behind the realisation of the first projects. Some parties make a distinction between before and after 2030, whereby a tailored approach may be required to ensure economic feasibility by 2030. The current support schemes are deemed insufficient to raise the financing needed for offshore electrolysis. Appropriate policy instruments need to be identified to accelerate development of offshore electrolysis.
- The business case for coupled electrolysis may also be under pressure in the longer term. In the case of coupled electrolysis, it is likely the levelised cost of electricity from an offshore wind farm can be used for the electricity price for green hydrogen production. Based on the assumptions in this study, the resulting hydrogen production cost is close to assumed import prices. If the import price is lower than the average domestic hydrogen production cost, there is a risk of an unprofitable component.

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Appendices

A. Overview of key assumptions

Offshore infrastructure:

Table 20: Cost assumptions

Investment cost component	Unit	Waarde (2040)	Source
Investment cost HVDC export cable	M€/GW/km	1.1	Competitiveness of North Sea Hydrogen, Guidehouse, 2020
Investment cost 66 kV inter-array cable	M€/km	0.5	Internal database, Guidehouse, 2021
Investment cost HVAC export cable	M€/km	2.0	Cost benefit analysis ogklimaaftryk af energiøer i Nordsøen og Østersøen (COWI, 2021)
Investment cost HVDC offshore/onshore convertor	GW	125	Competitiveness of North Sea Hydrogen (Guidehouse, 2020)
Investment cost electrolyser onshore	GW	300	Guidehouse interpretation of Hydrogen Europe projections (Hydrogen Europe, 2021), interviews with manufacturers, market consultation, and assumed learning rates
Investment cost electrolyser offshore	GW	405	35% more than onshore, based on outcome of market consultation
Investment cost hydrogen pipeline	M€/inch/km	0.065	Guidehouse interpretation of several sources (see section 5.8.2)
Investment cost hydrogen compression	M€/MW	3.4	Analysing future demand, supply, and transport of hydrogen (European Hydrogen Backbone, 2021)
Investment cost compression platform	M€	30	Based on volume of compressor, internal databse of platforms of similar size
Investment cost P2G platform	GW	920	Berekening gebaseerd op gewichtverschil HVDC platform en PtG platform, en maximum

			capaciteit PtG per platform van 500 MW.
Investment cost HVDC platform	GW	300	Competitiveness of North Sea Hydrogen (Guidehouse, 2020)
Investment cost HVAC platform	GW	141	Cost benefit analysis ogklimaaftryk af energiøer i Nordsøen og Østersøen (COWI, 2021)
Investment cost energy island (P2G)	GW	210.6	Guidehouse analysis based on Cost benefit analyse ogklimaaftryk af energiøer i Nordsøen og Østersøen (COWI, 2021)
Investment cost G2P	GW	900	Guidehouse internal database
Investment cost blue hydrogen	M€/GW_H_2	1098	Guidehouse internal database

Finanfial parameter assumptions:

Financial parameter	Unit	Value
Offshore wind	%	8%
Offshore infrastructure WACC	%	4%
Electrolyser WACC (domestic)	%	8%
Electrolyser WACC (foreign)	%	8%
Offshore wind	Years	25
Infrastructure lifetime	Years	25
Electrolyser lifetime	Years	25
Offshore wind capital recovery factor	-	0.09
Infrastructure capital recovery factor	-	0.06
Electrolyser capital recovery factor	-	0.09

Technical parameter assumptions:

Technical parameter	Unit	Value
Electrolyser efficiency	%	72%
Large scale natural gas/hydrogen fired power plant efficiency	%	63%
Small scale natural gas/hydrogen fired power plant efficiency	%	42%
Compression efficiency	%	75%
Net/gross ratio cable and pipeline length	-	1.3

Hydrogen compression capacity formula:

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

Compression capacity from North Sea Energy: A vision on hydrogen potential from the North Sea (North Sea Energy, 2020)

With the following parameters:

- Q, the flow rate (in kWh per day)
- LHV, lower heating value (33.33kWh/kg)
- Compressor Pin (input pressure) and Pout (output pressure)
- Z, hydrogen compressibility factor
- N, number of compression steps (1 step assumed)
- T, compressor input temperature (353K)
- γ, diatomic constant (1.4 for hydrogen)
- M_{H_2}, molecular mass of hydrogen (2.0158g/mol)
- η_{comp}, compressor efficiency (75% assumed)
- R, universal gas constant (8.314J/(K.mol))

B. Development in the demand for and supply of hydrogen and electricity 2015–2050

Regional

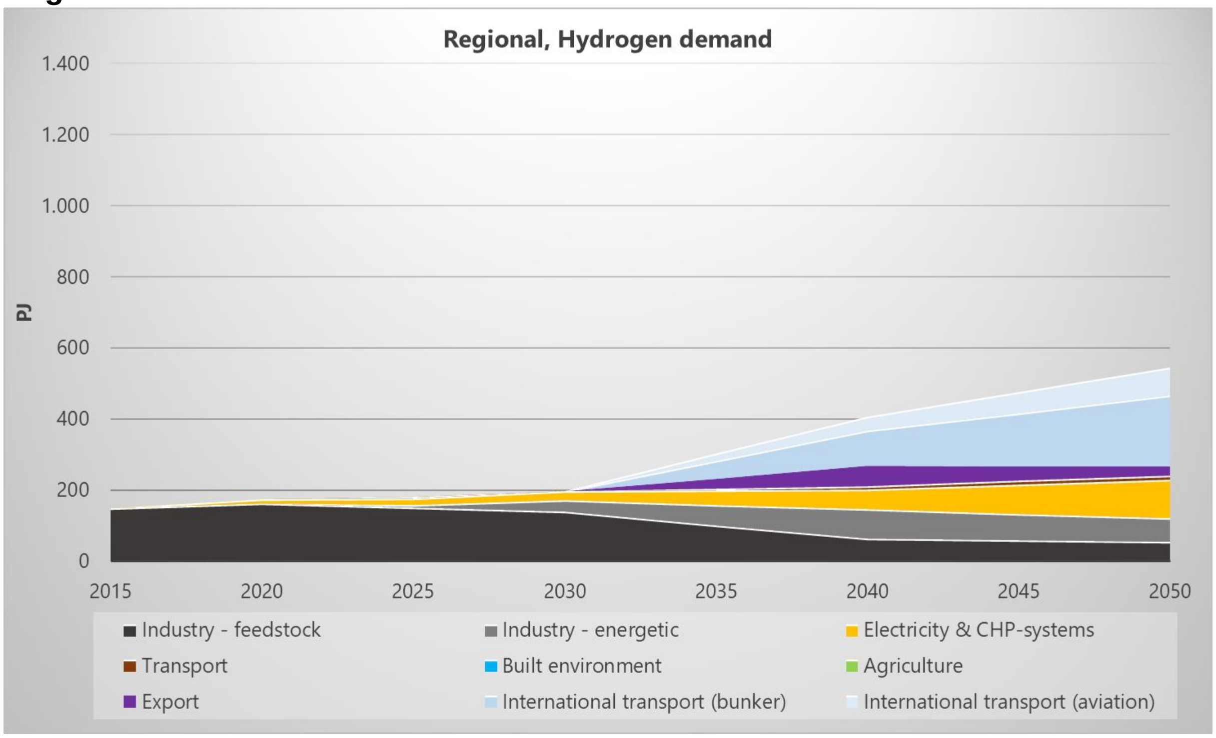

Figure 65. Development in hydrogen demand 2015–2050 Regional scenario

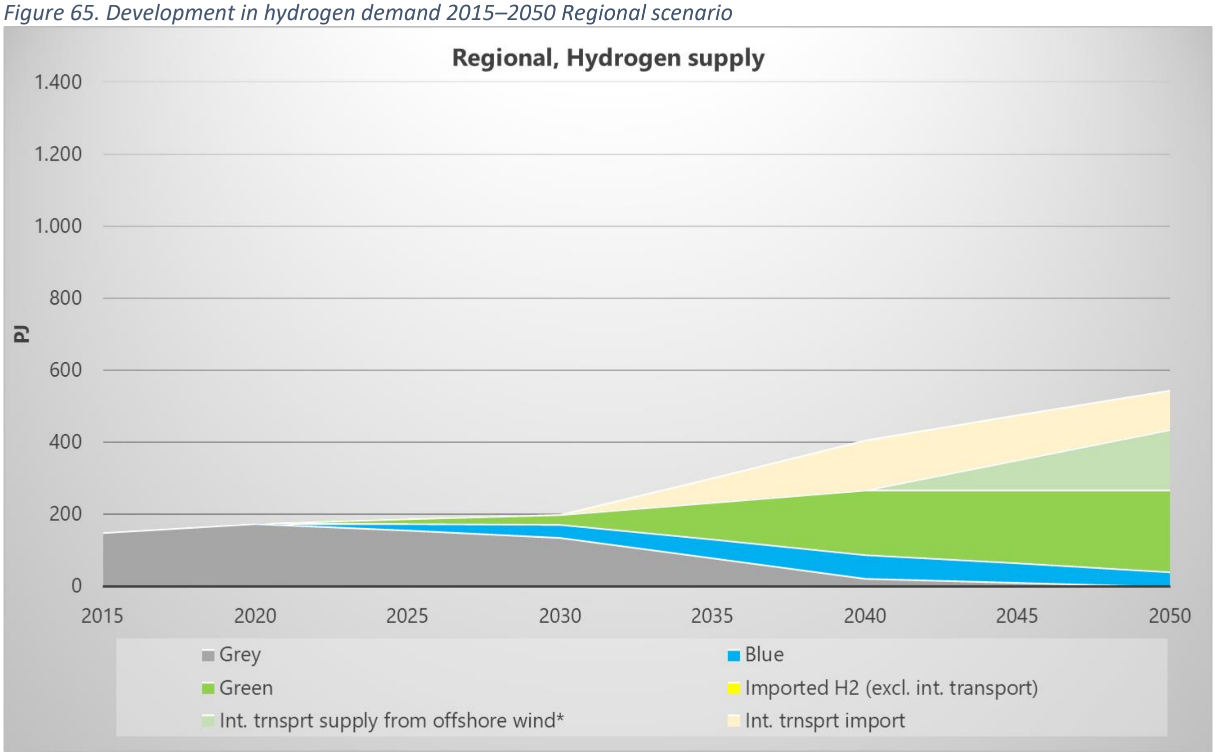

Figure 66. Development in hydrogen supply 2015–2050 Regional scenario

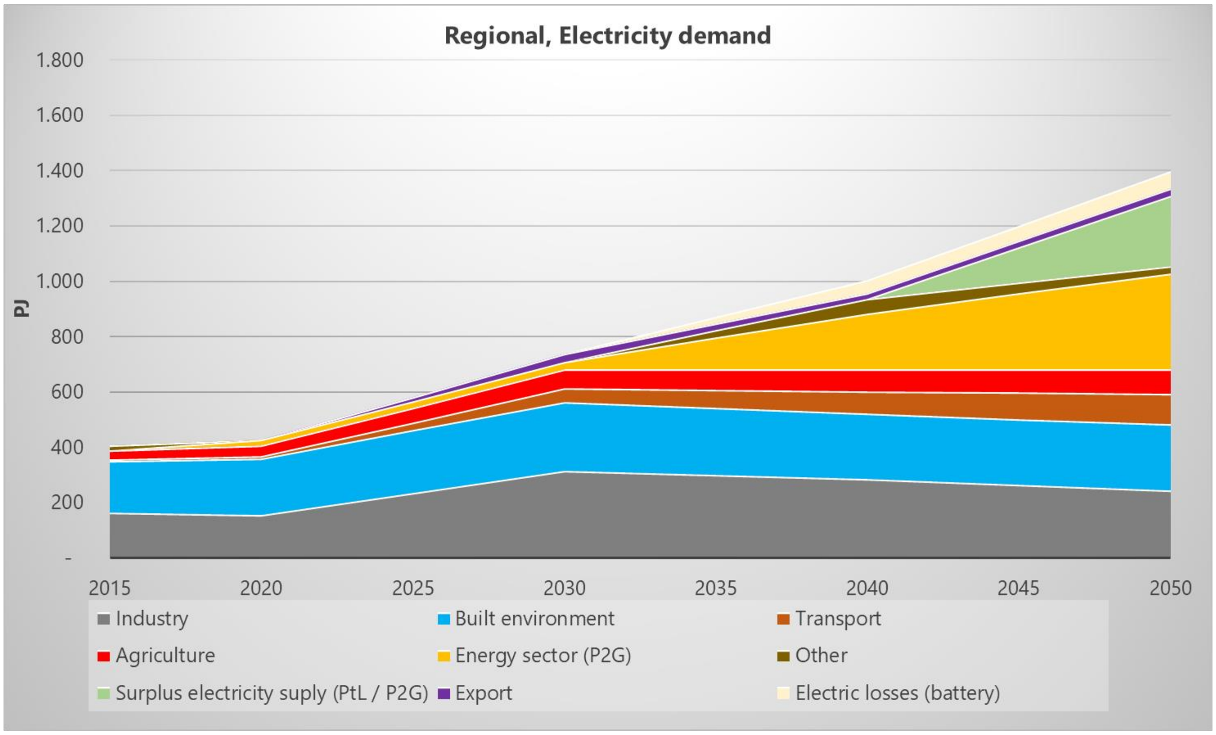

Figure 67. Development in electricity demand 2015–2050 Regional scenario. Please note: with regard to any electricity surpluses in the period 2040–2050, it has been assumed for the purpose of these figures that 100% of this surplus will be converted into green hydrogen (we apply a conversion ratio of 66%). The electricity available for conversion may differ in practice due to the use of alternative flexibility options.

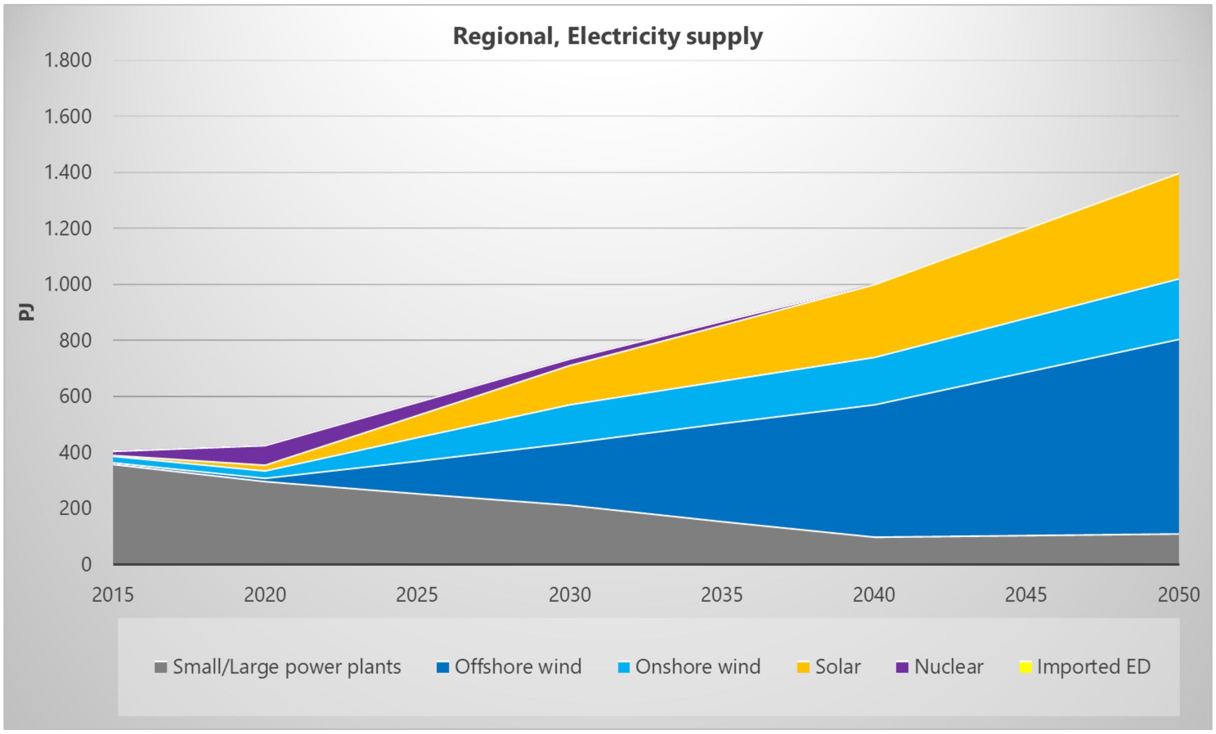

Figure 68. Development in electricity supply 2015–2050 Regional scenario

National

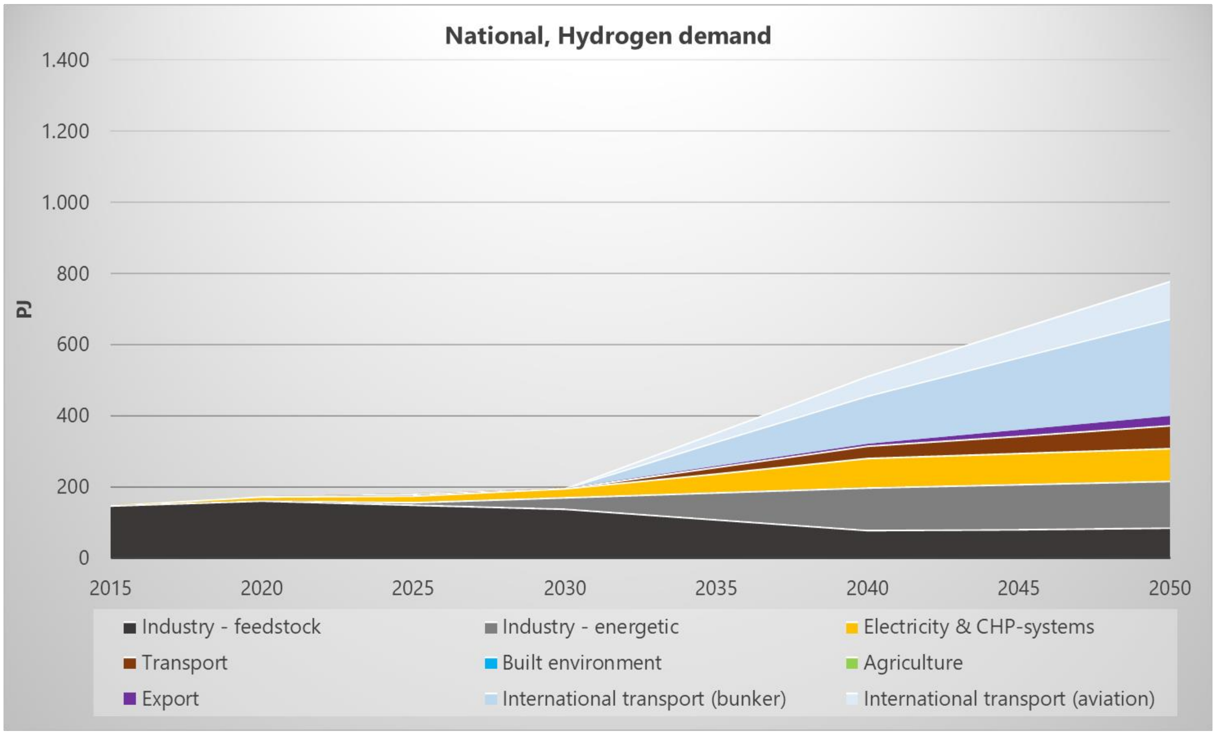

Figure 69. Development in hydrogen demand 2015–2050 National scenario

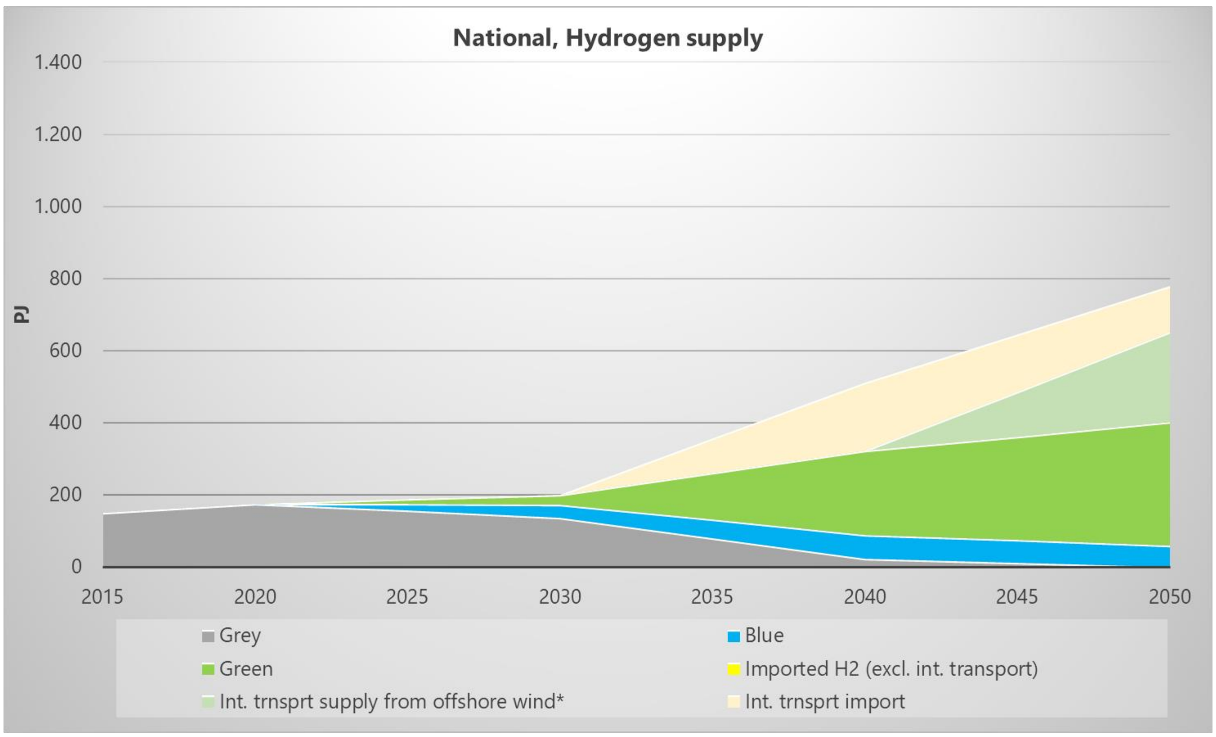

Figure 70. Development in hydrogen supply 2015–2050 National scenario

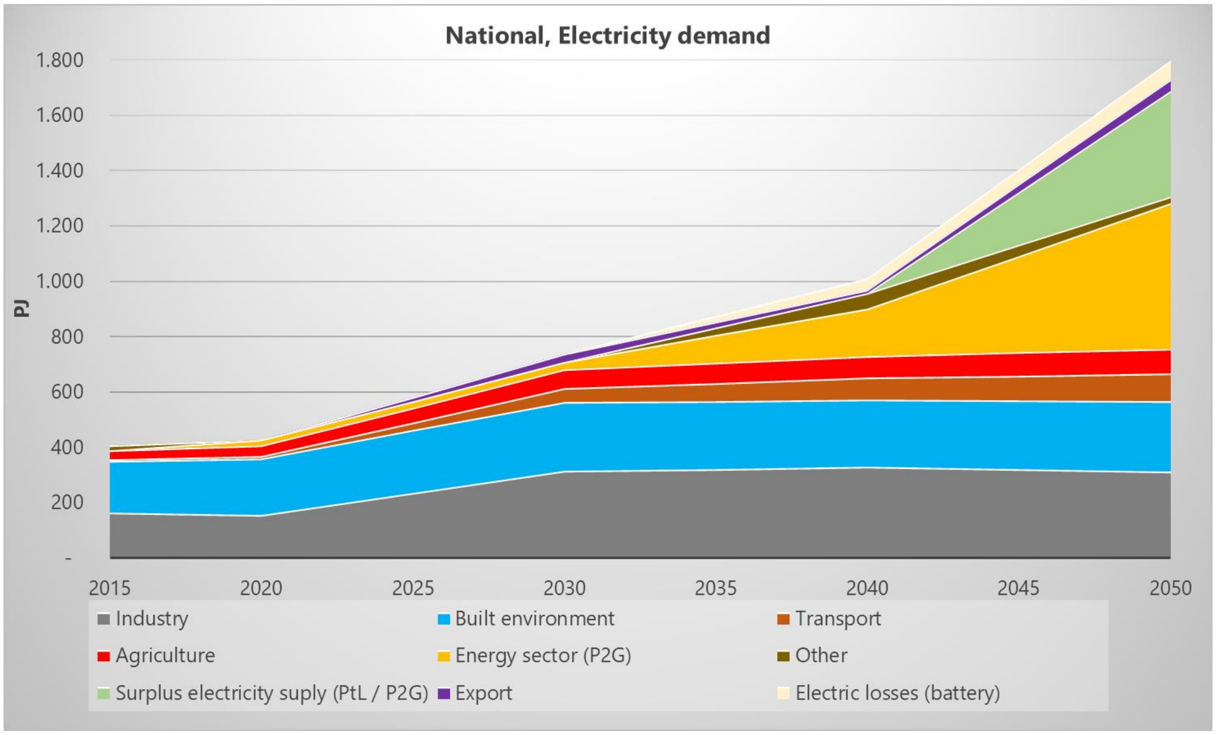

Figure 71. Development in electricity demand 2015–2050 National scenario.

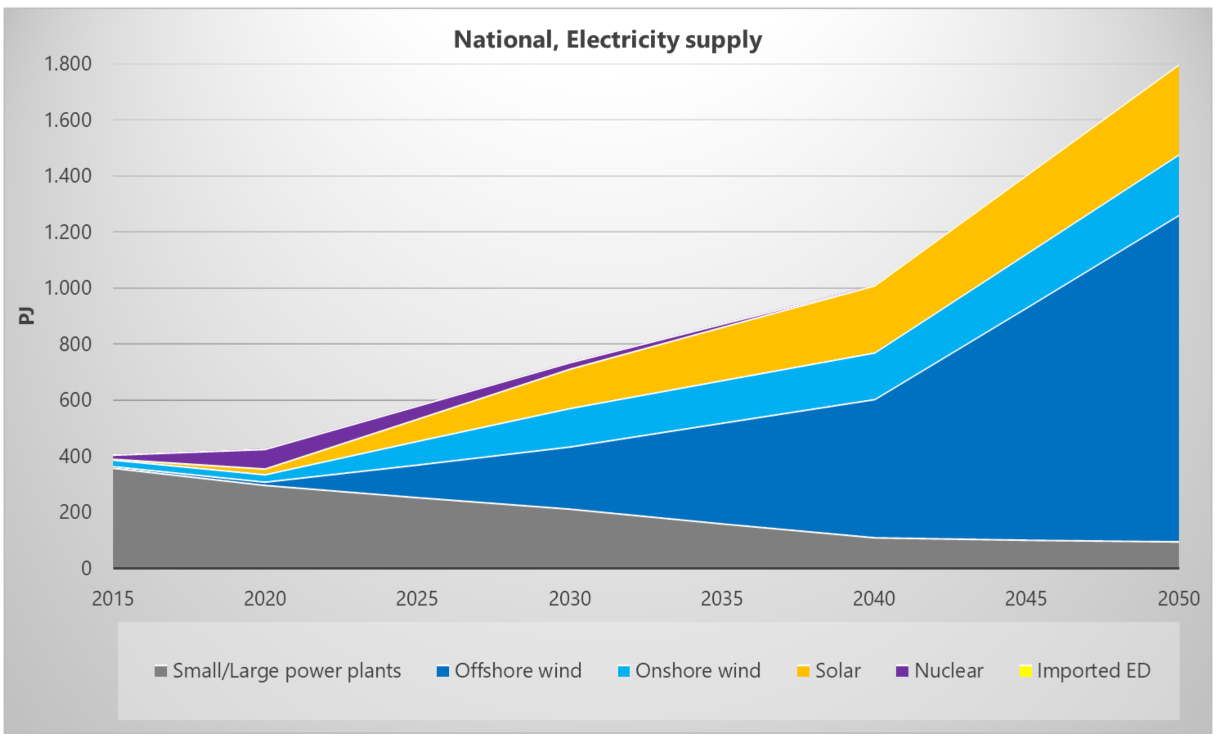

Figure 72. Development in electricity supply 2015–2050 National scenario

European

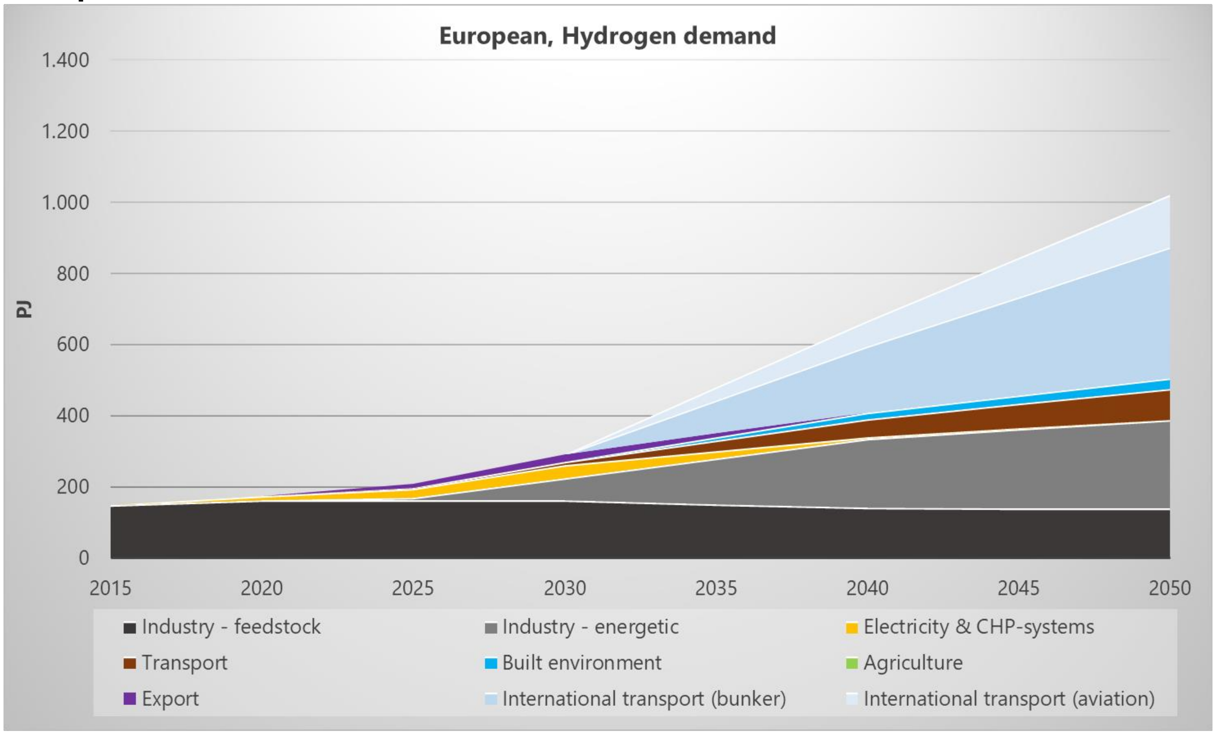

Figure 73. Development in hydrogen demand 2015–2050 European scenario

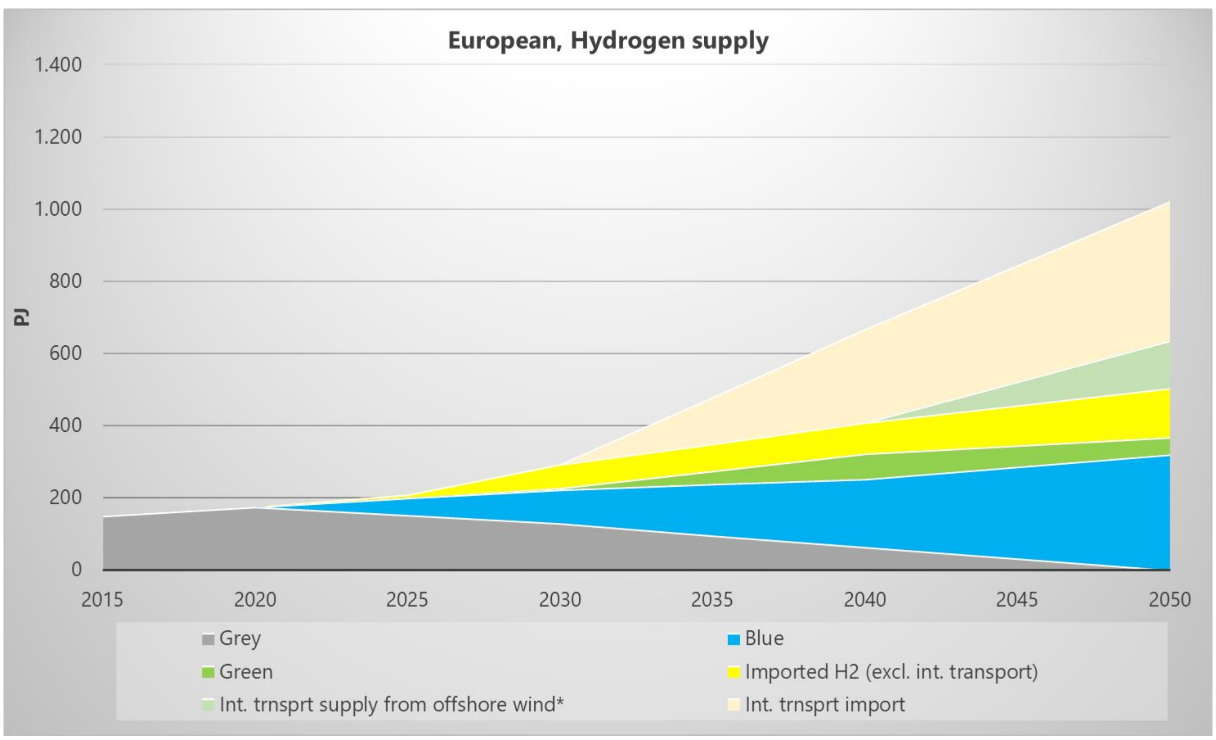

Figure 74. Development in hydrogen supply 2015–2050 European scenario

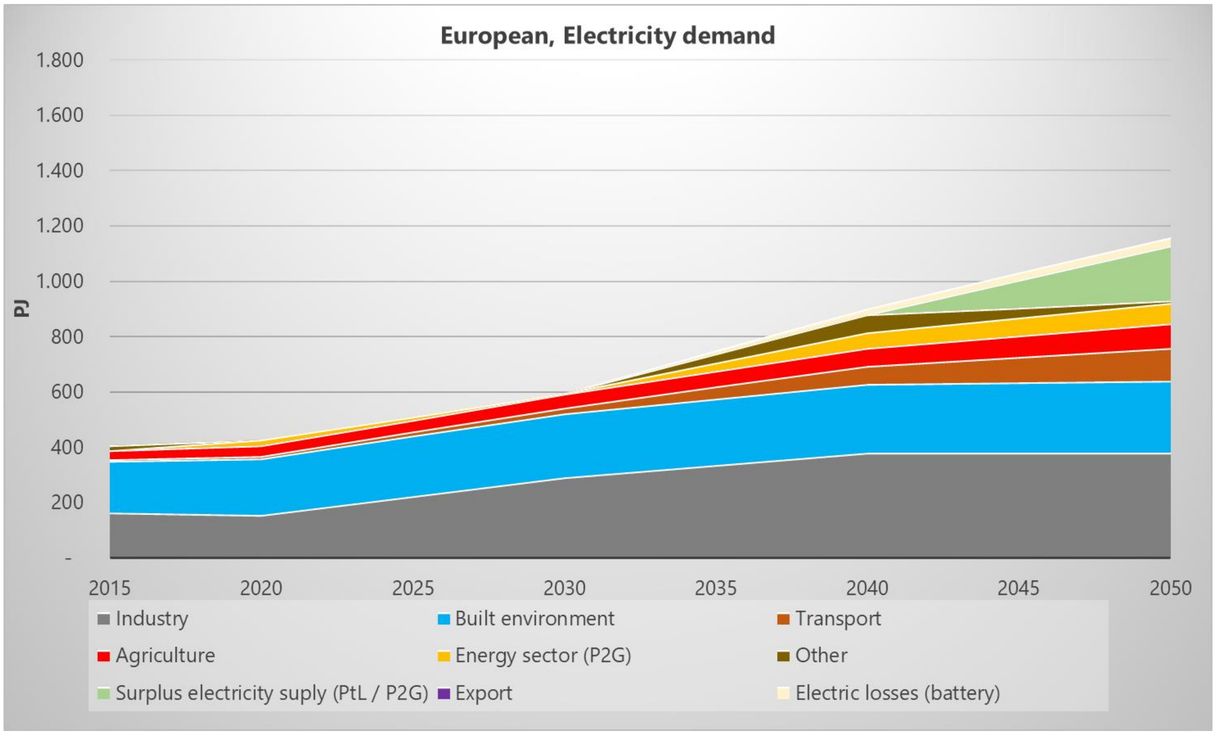

Figure 75. Development in electricity demand 2015–2050 European scenario.

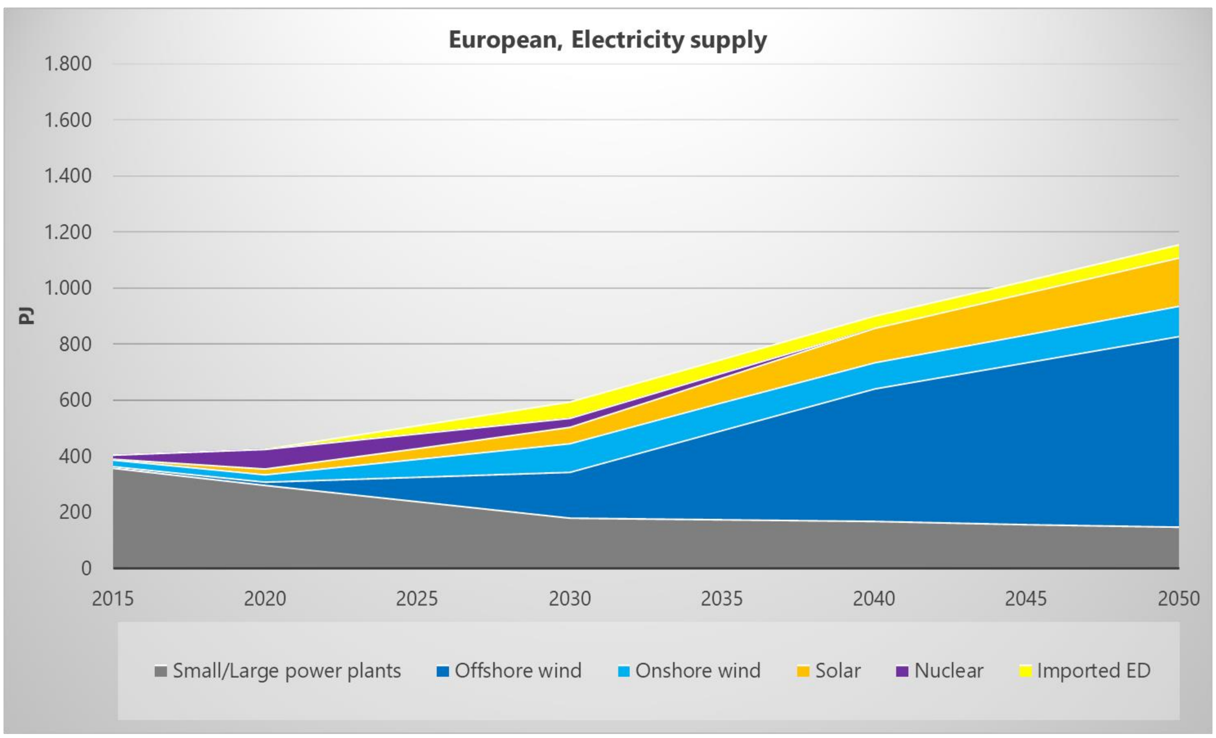

Figure 76. Development in electricity supply 2015–2050 European scenario

International

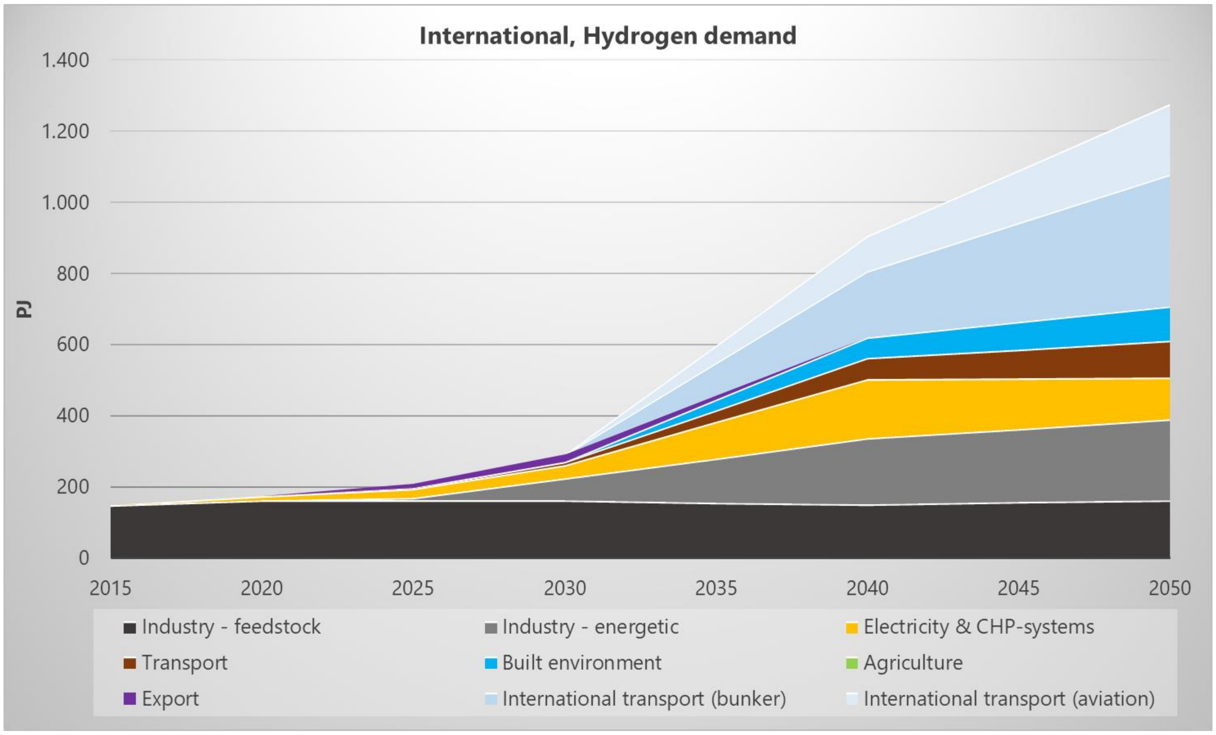

Figure 77. Development in hydrogen demand 2015–2050 International scenario

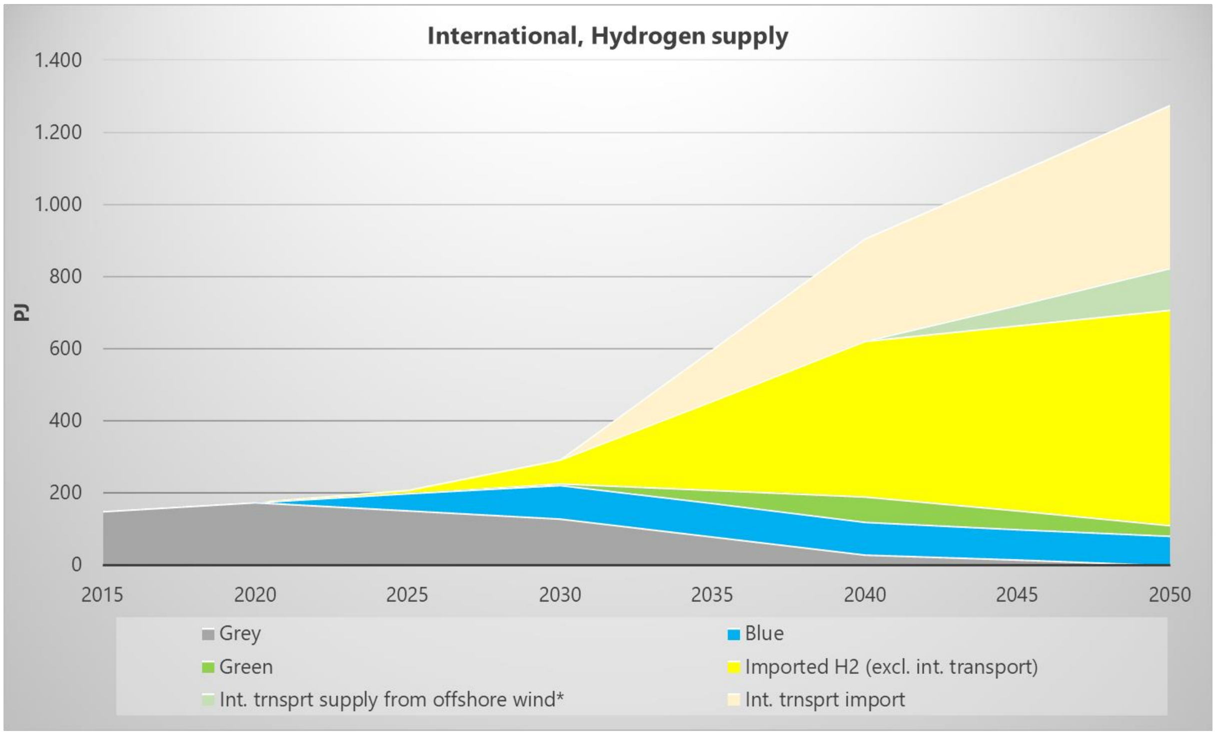

Figure 78. Development in hydrogen supply 2015–2050 International scenario

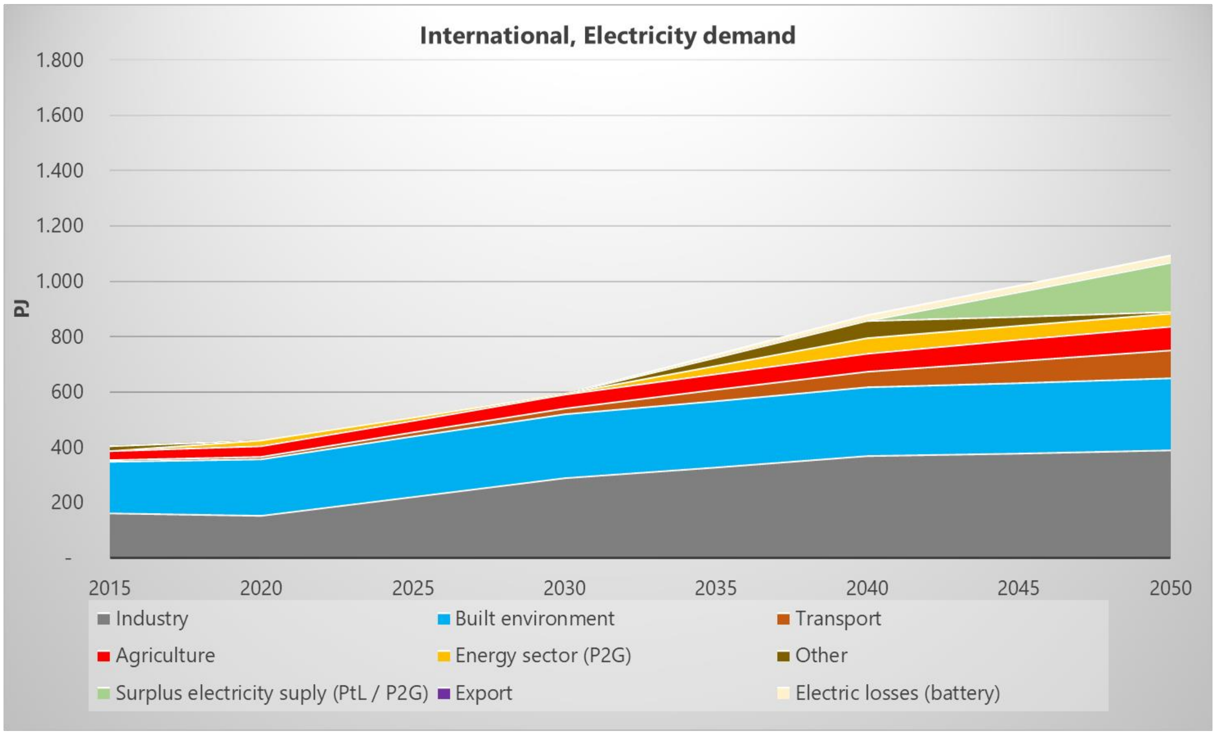

Figure 79. Development in electricity demand 2015–2050 International scenario.

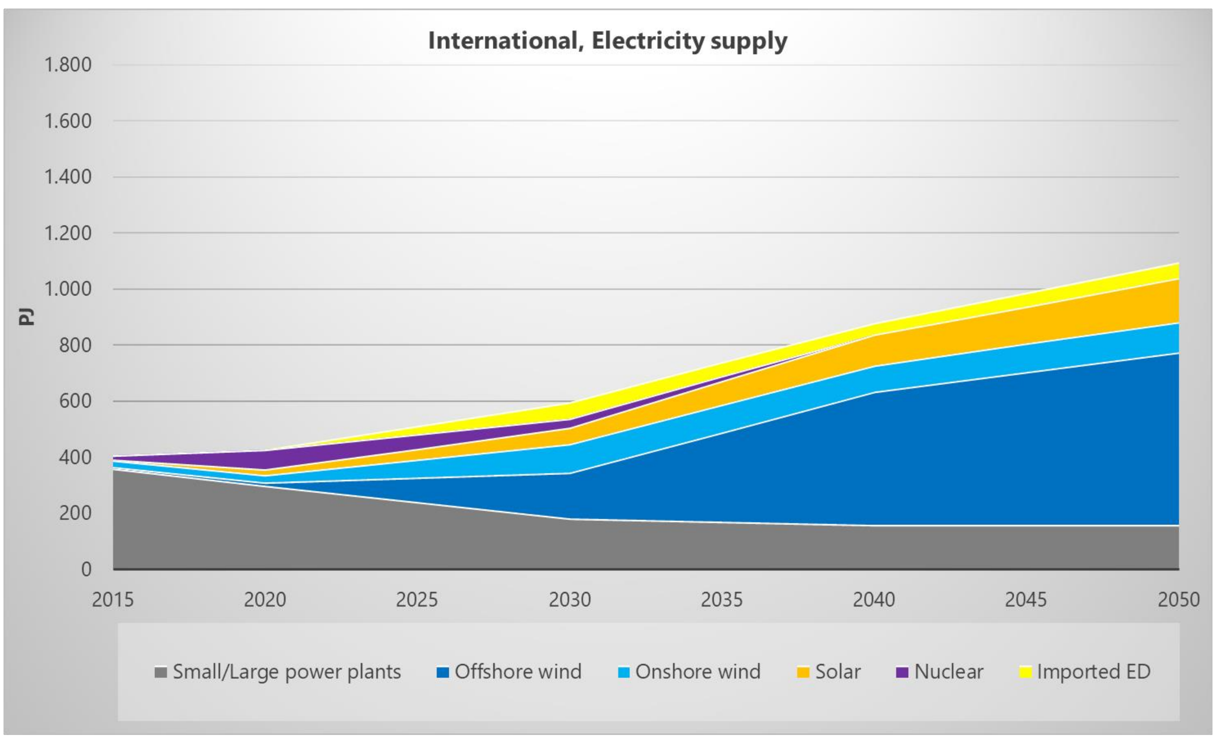

Figure 80. Development in electricity supply 2015–2050 International scenario

International+ (international with 38.5 GW of offshore wind energy)

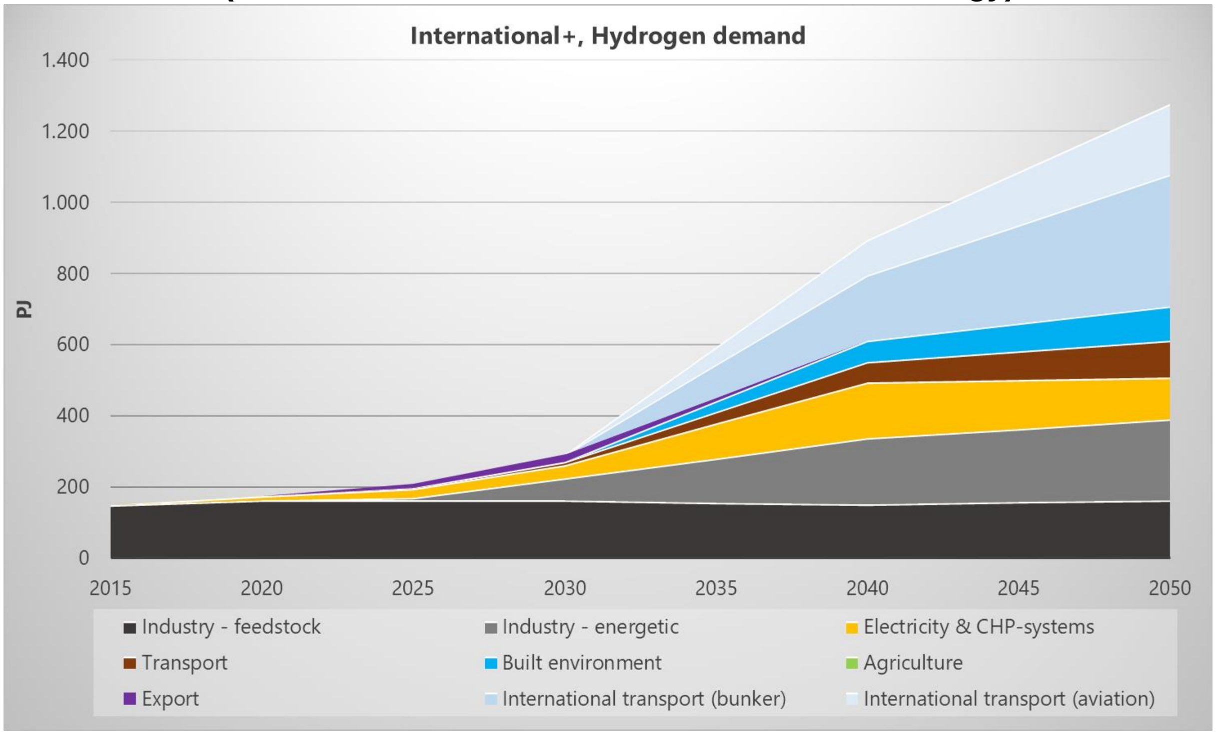

Figure 81. Development in hydrogen demand 2015–2050 International+ scenario

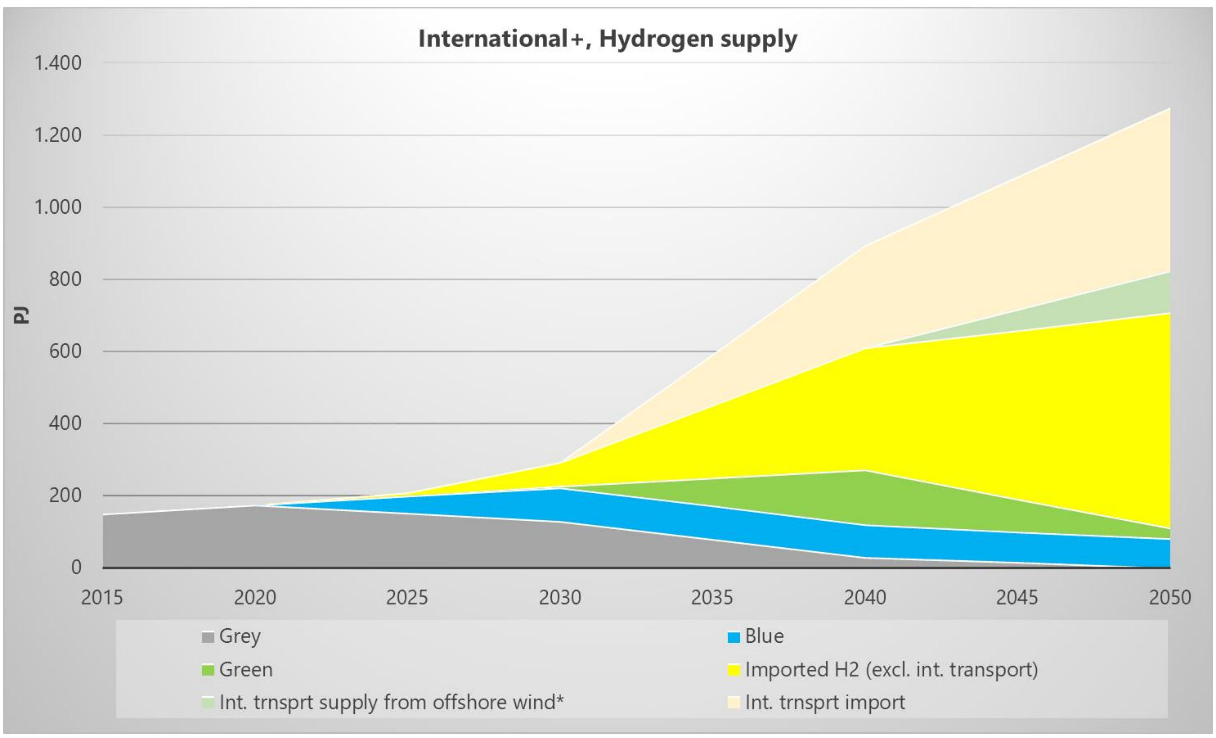

Figure 82. Development in hydrogen supply 2015–2050 International+ scenario

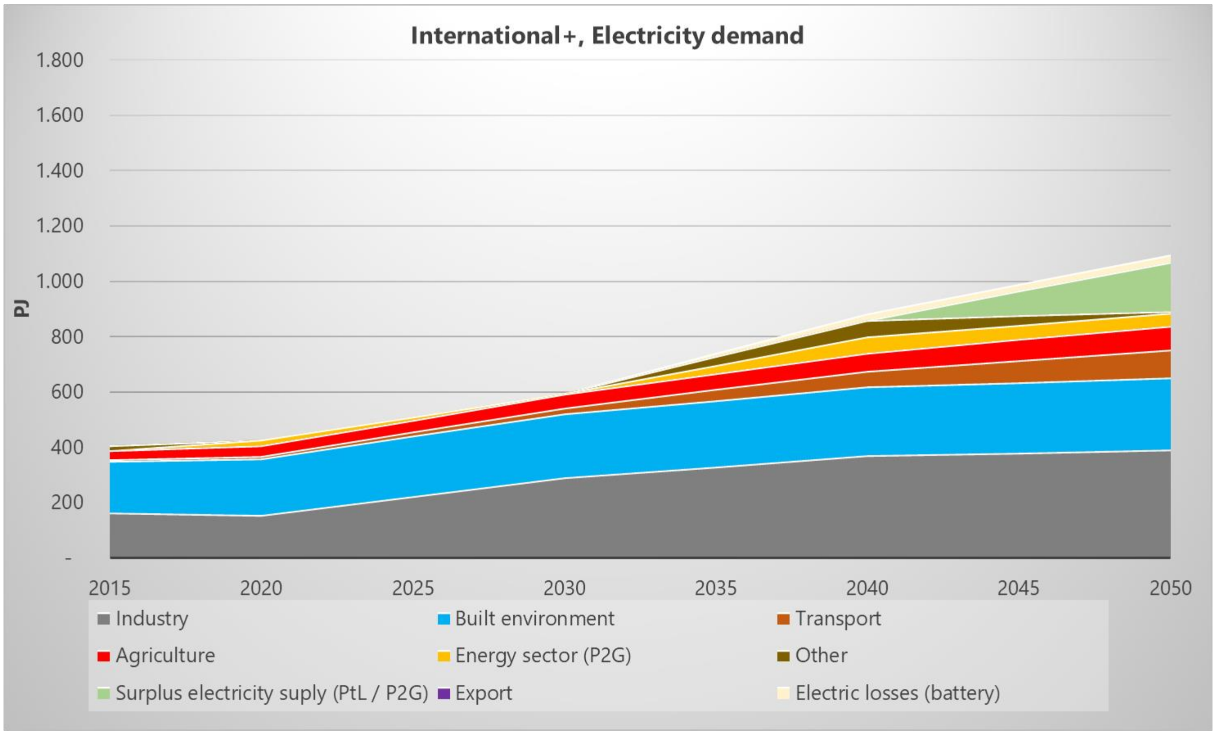

Figure 83. Development in electricity demand 2015–2050 International+ scenario.

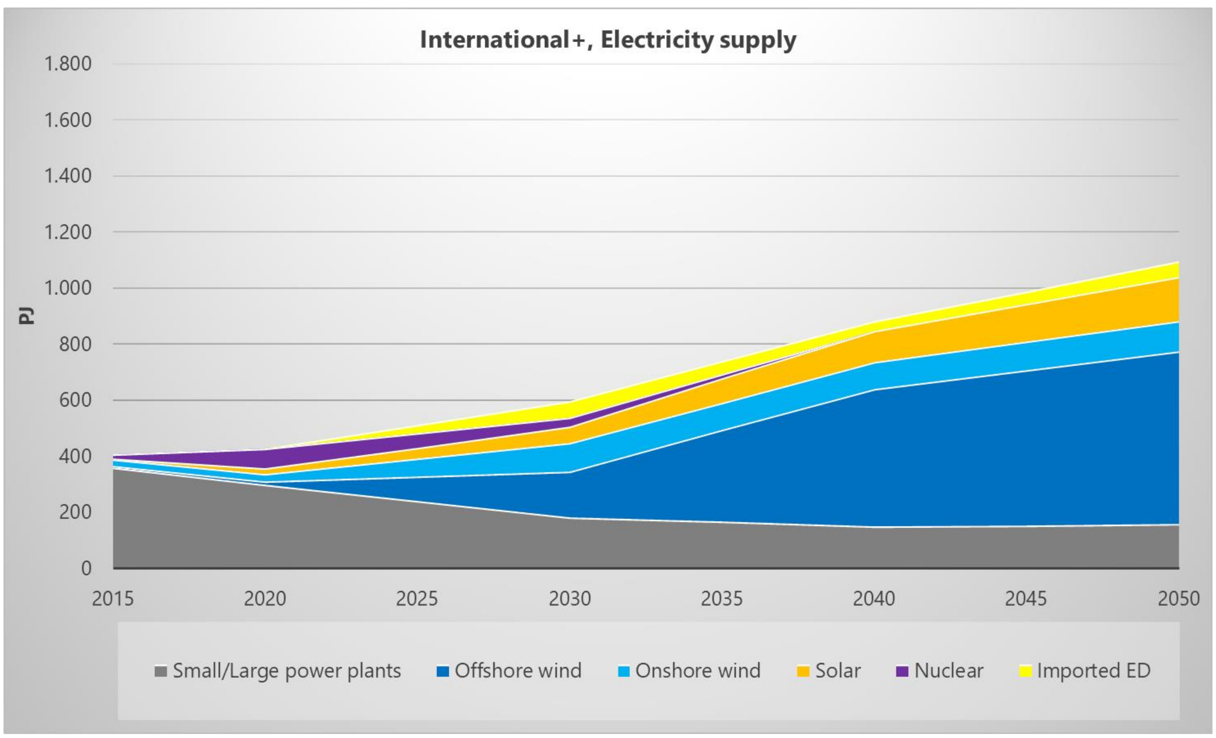

Figure 84. Development in electricity supply 2015–2050 International+ scenario

National+ (national with additional electrification)

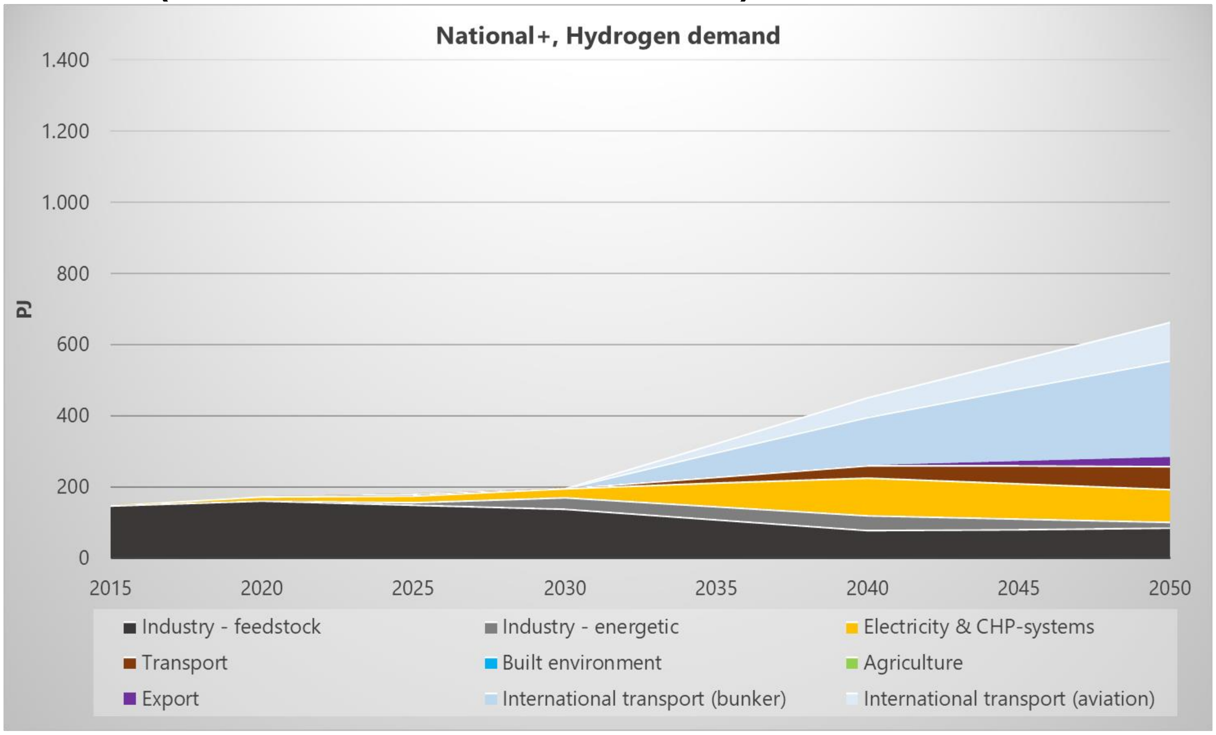

Figure 85. Development in hydrogen demand 2015–2050 National+ scenario

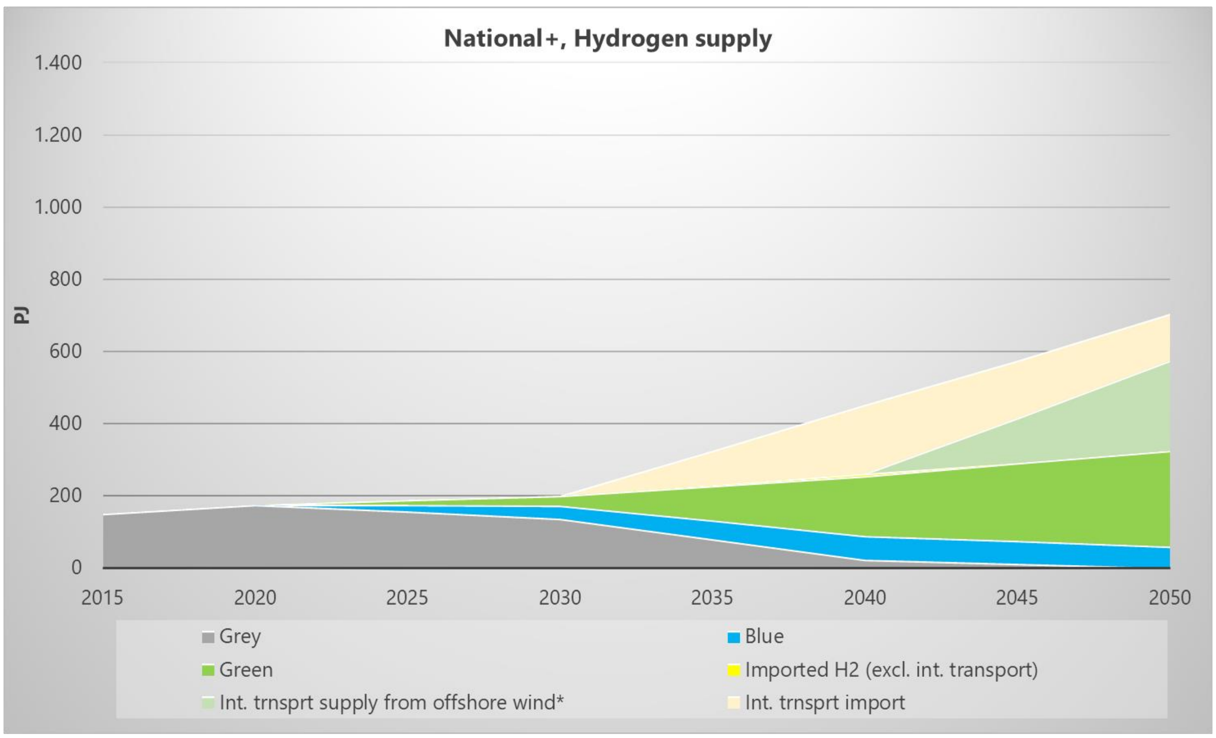

Figure 86. Development in hydrogen supply 2015–2050 National+ scenario

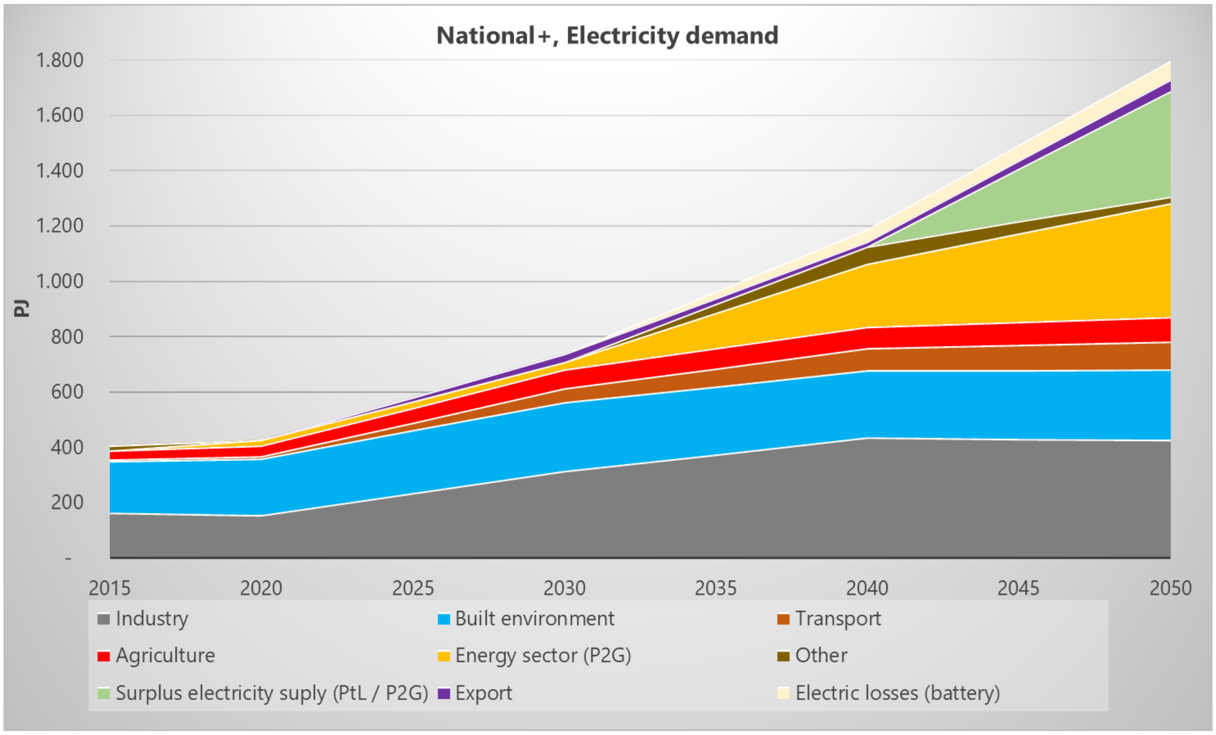

Figure 87. Development in electricity demand 2015–2050 National+ scenario.

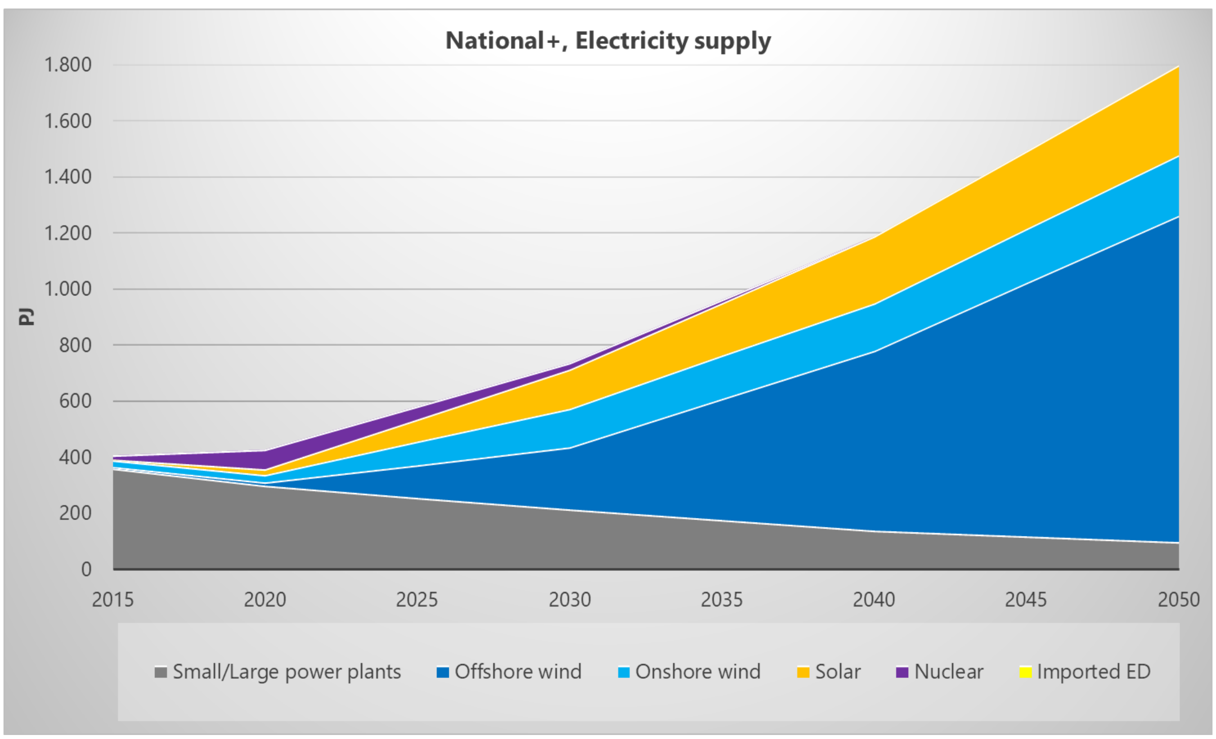

Figure 88. Development in electricity supply 2015–2050 National+ scenario

C. Tables with key results flexibility analysis and electrolysis optimisation for all solutions, scenarios, and variants

Table 21: Overview of key results flexibility analysis and electrolysis optimisation Regional scenario

Regional scenario			Potential solution				
Flexibility source	**Attribute**	**Unit**	**Landfall focused on Maasvlakte**	**Landfall focused on Eemshaven**	**Coupled electrolysis**	**Anti-congestion electrolysis**	**Offshore electrolysis**
Import and export of electricity	Import volume	TWh	10.1	10.1	11.7	10.9	-
	Peak import	GW	12.0	12.0	12.2	12.0	-
	Export volume	TWh	17.6	17.6	15.8	16.7	-
	Peak export	GW	14.8	14.8	14.8	14.8	-
	FLH	hour/year	1876	1876	1857	1866	-
G2P (large)	Capacity	GW	11.6	11.6	11.3	11.3	-
	Energy volume	TWh	19.5	19.5	21.1	20.0	-
	FLH	hour/year	1680	1680	1868	1769	-
G2P (small)	Capacity	GW	16.6	16.6	16.9	16.9	-
	Energy volume	TWh	3.2	3.2	3.8	3.5	-
	FLH	hour/year	193	192	223	208	-
Batteries	Peak charge	GW	37.4	37.4	36.9	37.5	-
	Peak discharge	GW	31.9	31.9	29.8	30.2	-
	Capacity	GWh	260	260	254	255	-
	Energy volume	TWh	37.6	37.6	37.4	37.3	-
Electrolysis	Capacity	GW	19.7	19.7	20.3	20.5	-
	Energy volume	TWh	62.7	62.7	69.1	65.9	-
	FLH	hour/year	3184	3184	3403	3209	-
Curtailment	Capacity	GW	34.9	34.9	33.2	32.8	-
	Energy volume	TWh	7.1	7.1	6.4	6.5	-
	FLH	hour/year	205	205	193	199	-

[1] *All capacities/volumes (W/Wh) are expressed in electrical units.*

Table 22: Overview of key results flexibility analysis and electrolysis optimisation National scenario

National scenario			Potential solution				
Flexibility source	**Attribute**	**Unit**	**Landfall focused on Maasvlakte**	**Landfall focused on Eemshaven**	**Coupled electrolysis**	**Anti-congestion electrolysis**	**Offshore electrolysis**
Import and export of electricity	Import volume	TWh	8.8	8.8	13.4	11.8	14.1
	Peak import	GW	12.2	12.2	12.2	12.2	12.6
	Export volume	TWh	19.2	19.2	13.6	15.4	13.0
	Peak export	GW	14.8	14.8	14.8	14.8	14.8
	FLH	hour/year	1893	1893	1829	1833	1831
G2P (large)	Capacity	GW	13.1	13.0	12.4	12.1	12.1
	Energy volume	TWh	20.6	20.6	26.4	22.9	26.8
	FLH	hour/year	1570	1577	2124	1900	2218
G2P (small)	Capacity	GW	15.9	16.0	16.7	17.0	17.0
	Energy volume	TWh	2.6	2.7	4.1	3.6	4.5
	FLH	hour/year	166	168	246	213	266
Batteries	Peak charge	GW	35.9	35.9	34.2	34.8	34.2
	Peak discharge	GW	34.9	34.9	28.5	29.1	27.6
	Capacity	GWh	264	264	242	239	241
	Energy volume	TWh	35.3	35.3	34.6	34.2	34.4
Electrolysis	Capacity	GW	23.3	23.3	24.9	25.4	26.5
	Energy volume	TWh	74.5	74.5	94.7	87.2	101.9
	FLH	hour/year	3203	3203	3802	3436	3846
Curtailment	Capacity	GW	35.4	35.4	30.4	29.6	28.8
	Energy volume	TWh	7.8	7.8	5.5	5.8	5.2
	FLH	hour/year	221	221	183	195	181

[1] *All capacities/volumes (W/Wh) are expressed in electrical units.*

Table 23: Overview of key results flexibility analysis and electrolysis optimisation European scenario

European scenario			Potential solution				
Flexibility source	**Attribute**	**Unit**	**Landfall focused on Maasvlakte**	**Landfall focused on Eemshaven**	**Coupled electrolysis**	**Anti-congestion electrolysis**	**Offshore electrolysis**
Import and export of electricity	Import volume	TWh	18.0	18.0	20.7	19.7	-
	Peak import	GW	14.8	14.8	14.8	14.8	-
	Export volume	TWh	8.8	8.8	6.9	7.6	-
	Peak export	GW	14.8	14.8	14.6	14.8	-
	FLH	hour/year	1810	1810	1869	1845	-
G2P (large)	Capacity	GW	11.9	11.9	12.0	11.9	-
	Energy volume	TWh	36.3	36.3	39.9	37.9	-
	FLH	hour/year	3045	3044	3336	3172	-
G2P (small)	Capacity	GW	16.0	16.0	16.0	16.0	-
	Energy volume	TWh	7.4	7.4	8.2	7.6	-
	FLH	hour/year	464	464	513	473	-
Batteries	Peak charge	GW	19.7	19.7	19.4	19.8	-
	Peak discharge	GW	25.3	25.3	23.2	23.6	-
	Capacity	GWh	182	182	173	172	-
	Energy volume	TWh	21.2	21.2	20.6	20.6	-
Electrolysis	Capacity	GW	7.5	7.5	8.6	8.9	-
	Energy volume	TWh	18.6	18.6	28.7	24.2	-
	FLH	hour/year	2465	2465	3315	2737	-
Curtailment	Capacity	GW	21.9	21.9	19.6	19.3	-
	Energy volume	TWh	4.8	4.8	3.9	4.0	-
	FLH	hour/year	220	220	201	209	-

[1] *All capacities/volumes (W/Wh) are expressed in electrical units.*

Table 24: Overview of key results flexibility analysis and electrolysis optimisation International scenario

International scenario			Potential solution				
Flexibility source	**Attribute**	**Unit**	**Landfall focused on Maasvlakte**	**Landfall focused on Eemshaven**	**Coupled electrolysis**	**Anti-congestion electrolysis**	**Offshore electrolysis**
Import and export of electricity	Import volume	TWh	17.6	17.6	20.2	19.2	-
	Peak import	GW	14.6	14.6	14.8	14.6	-
	Export volume	TWh	9.1	9.1	7.2	7.9	-
	Peak export	GW	14.8	14.8	14.2	14.8	-
	FLH	hour/year	1807	1807	1855	1832	-
G2P (large)	Capacity	GW	12.2	12.2	11.7	11.6	-
	Energy volume	TWh	35.7	35.7	38.5	36.3	-
	FLH	hour/year	2931	2931	3281	3131	-
G2P (small)	Capacity	GW	14.8	14.8	15.3	15.3	-
	Energy volume	TWh	6.4	6.4	7.8	7.3	-
	FLH	hour/year	433	433	513	478	-
Batteries	Peak charge	GW	18.7	18.7	18.4	18.8	-
	Peak discharge	GW	25.0	25.0	22.9	23.3	-
	Capacity	GWh	179	179	167	167	-
	Energy volume	TWh	20.3	20.3	19.7	19.6	-
Electrolysis	Capacity	GW	7.6	7.6	8.6	8.9	-
	Energy volume	TWh	19.0	19.0	28.8	24.4	-
	FLH	hour/year	2493	2493	3339	2750	-
Curtailment	Capacity	GW	21.2	21.2	19.2	18.8	-
	Energy volume	TWh	4.7	4.7	3.9	3.9	-
	FLH	hour/year	221	221	202	207	-

[1] *All capacities/volumes (W/Wh) are expressed in electrical units.*

Table 25: Overview of key results flexibility analysis and electrolysis optimisation variants

Variants			**National+ extra electrification**		**International+ additional offshore wind**	
Flexibility source	**Attribute**	**Unit**	**Anti-congestion electrolysis**	**Offshore electrolysis**	**Anti-congestion electrolysis**	**Offshore electrolysis**
Import and export of electricity	Import volume	TWh	11.4	11.4	18.3	21.6
	Peak import	GW	13.2	13.2	14.2	14.8
	Export volume	TWh	15.8	15.8	8.6	6.5
	Peak export	GW	14.8	14.8	14.8	13.3
	FLH	hour/year	1832	1832	1812	1903
G2P (large)	Capacity	GW	14.1	13.8	11.5	11.7
	Energy volume	TWh	28.3	28.1	34.0	40.1
	FLH	hour/year	2008	2035	2967	3413
G2P (small)	Capacity	GW	16.0	16.3	15.4	15.4
	Energy volume	TWh	4.0	4.3	6.6	8.1
	FLH	hour/year	251	263	430	526
Batteries	Peak charge	GW	35.4	35.4	18.6	18.5
	Peak discharge	GW	34.9	34.9	23.3	21.9
	Capacity	GWh	273	273	166	162
	Energy volume	TWh	36.3	36.3	19.3	19.4
Electrolysis	Capacity	GW	20.6	20.6	16.0	17.4
	Energy volume	TWh	60.3	60.3	55.2	73.5
	FLH	hour/year	2920	2921	3445	4229
Curtailment	Capacity	GW	34.2	34.2	18.4	17.4
	Energy volume	TWh	7.2	7.2	4.0	3.5
	FLH	hour/year	211	211	215	203

[1] *All capacities/volumes (W/Wh) are expressed in electrical units.*