Netbeheer Nederland

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2030-2050 Integrated Infrastructure Outlook

Foreword

Making the Netherlands climate-neutral by 2050 is a major challenge, but it can be done. To this end, this outlook outlines four climate-neutral energy systems and development paths for flexibility resources and energy infrastructure.

The objective of the Integrated Infrastructure Outlook is to develop the kind of insight into the energy infrastructure, flexibility resources and system integration that is needed to be able to build a reliable, effective and robust climate-neutral energy system by 2050.

This infrastructure outlook is intended as input for network operators to analyse the long-term impact of various developments on the energy infrastructure and identify, at an early stage, relevant factors during the transition towards a climate-neutral energy system.

This second edition of II3050 can, therefore, also serve as a guideline for various stakeholders such as market parties and provide government bodies with information as input for their policy-making processes. Certain results from this outlook have already been used as input for the National Energy System Plan and other national programmes, such as the *Programma Energiehoofdinfrastructuur* (PEH) and the *Verbindingen Aanlanding Wind Op Zee* (VAWOZ), which are run by the Dutch Ministry of Economic Affairs and Climate Policy to provide further direction for government policy.

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Main conclusions

Climate neutrality for the Netherlands can be achieved by 2050 with each of the four scenarios presented in this second edition of II3050. This latest edition of the outlook paints an up-to-date picture of the developments that will be needed to reach climate neutrality, with a specific focus on the energy infrastructure. This study is an update to the first edition of II3050. In this report, the emphasis is on the four climate-neutral energy systems, the associated infrastructure needs and the development pathways for this infrastructure. The main conclusions from the first edition of the Integrated Infrastructure Outlook are still valid. At the time, the conclusions drawn were that implementation of the four scenarios will require:

1. considerable expansion of the electricity infrastructure, a hydrogen transport network with nationwide coverage, and creation of infrastructure for heat and CO_2;

2. large-scale flexibility resources for all energy carriers (electricity, hydrogen, green gas, heat), including new forms of flexibility resources alongside the existing ones;

3. significantly more expenditure and space, both for infrastructure and for flexibility resources;

4. careful selection of locations. Smart location choices for flexibility resources and supply and demand development will limit the impact on the energy infrastructure;

5. greater speed. The current lead times for network modifications are creating bottlenecks due to the time it takes for permits to be issued and land to become available, and delays in planning permission and the availability of material. The availability of sufficient qualified staff should be taken into account in making strategic choices;

6. a long-term perspective. The choices made for a new integrated energy system are key for an efficient transition towards a reliable and climate-neutral energy supply. A long-term perspective is also important to be able to identify and prepare the necessary measures in time, and to subsequently implement them in time as well, in step with increasing demand for them from society.

In the second edition of II3050, several of these conclusions and dilemmas come to the fore even more sharply than in the first edition. On top of that, the outlook goes into greater depth on several topics. The main conclusions are all based on the four scenarios analysed, which present the most realistic playing field possible given the knowledge available today. However, seeing as uncertainty about the future is inherent to any scenario study, the main conclusions presented here have to be viewed in that light. One example of a source of major uncertainty in the scenarios is industry. What industries will there be in the Netherlands in 2050 and how much energy will they need? Another example is the uncertainty about the costs involved in electrolysis, and consequently the price of hydrogen, which will influence both supply and demand.

These main conclusions first and foremost address the scenarios, the energy system of 2050, and the issues involved. Next, the focus shifts to the flexibility resources, i.e. conversion, storage, steering supply and demand, and transmissions to and from other countries. This is followed by the main insights regarding the energy infrastructure. Finally, conclusions on the energy system are drawn from the perspectives of cost, space, feasibility and feedstocks.

Scenarios and the energy system

Challenges in the energy system

For the first time, the II3050 outlook looks not only at the energy system in detail, but also at the carbon issue. In 2050, there will still be a need for plastics, chemicals and (carbonated) foodstuffs. This means that renewable sources of carbon for these products will have to be found in the future, and it also means that CO_2 capture and recycling will be needed in places where fossil carbon is still used. For plastics made from petroleum, for example, this means that they have to be recycled fully after use, or, if that is no longer possible, that the CO_2 will have to be captured during waste incineration and reused as a feedstock. The problem is that circular use of materials and substances can only meet a limited proportion of the carbon demand for production processes. There are also new technologies that can be used to capture carbon from the air (direct air capture), but it is as yet unclear how feasible this is. In the Netherlands, the scarcity of renewable carbon leads to an allocation issue: what use of renewable carbon would be the wisest choice given the many applications that could benefit from it? Where does the use of renewable carbon create the most value? And is that also the choice society makes? See Section 2.3.

The production of synthetic fuels and feedstocks will require renewable carbon, in addition to large volumes of energy. How much synthetic fuel and feedstock the Netherlands will still produce by 2050 remains to be seen. Obviously, the question of whether all or part of today's energy-intensive industry will still exist in the Netherlands, or maintain its current size while becoming sustainable, has a major impact on the extent of the infrastructure and flexibility resources that will be needed, including dispatchable power plants, conversion and storage. Increased production of synthetic fuels and feedstocks will have an adverse impact on the business case for electrolysis and power-to-heat plants (fewer operating hours). The business case for power plants would, however, improve (more operating hours) and more hydrogen storage would be needed to keep the plants running. Extensive production of renewable energy combined with relatively limited manufacturing of synthetic products means, on the other hand, that more electricity would be transported to other countries on an ongoing basis, which would require considerably more infrastructure. The Netherlands will have to weigh the pros and cons of the production of synthetic products and other energy-intensive industrial processes within its borders. See Section 2.3.

Additionally, there is also the ambition to create a zero-CO_2 electricity system by 2035, as announced recently in the 2050 Energy System Outlook. This ambition was not yet incorporated in the 2024 IP scenarios, which are also used in this outlook. How does this ambition impact on II3050? Bringing forward the target of having a fully zero-CO_2 electricity system is expected to require even more rapid scaling up of infrastructure, hydrogen production, imports and storage, renewable energy generation, efficient energy use, and flexibility in the form of conversion, storage and demand response. This will put even greater pressure on costs, space, feasibility and feedstocks during the period through to 2035. In addition, it cannot be ruled out that such an accelerated approach will have an adverse impact on the energy transition in other sectors. See Section 2.3.

Flexibility resources

In the 2024 IP scenarios, demand in the electricity system will, by 2030, exceed the generation capacity for renewable energy at peak times by around 25 GW, which is 1.5 times more than today. Between 2030 and 2050, this figure will increase to 35-50 GW. However, there will be many times when there are surpluses, increasing at peak times from 45 GW in 2030 to 65-95 GW in 2050. In order to be able to respond to these shortages and surpluses, a large and diverse portfolio of flexibility resources will have to be created. This growth of flexibility resources is driven mainly by technologies that have yet to be scaled up to anything like the required extent.

The assumption in the scenarios is that, by 2050, 25-50% of demand from industry will align flexibly with the available (renewable) supply and that other users, such as the transport and mobility sector, will also make smarter use of energy. The capacity of international interconnections will be 2.5 to 3.5 times greater than it is today. In addition, the assumption is that, in a year with a normal weather profile, 15-20 GW in power produced by dispatchable power plants (comparable to now) and 40-70 GW from batteries will be used to prevent shortages. In the 2050 scenarios, surpluses are not only used to charge batteries and for exports, but also utilised for flexible electrolysis (10-25 GW) and power-to-heat units (3-11 GW). On top of that, wind and solar power generation will be reduced in a limited number of situations (maximum of 35-50 GW). See Section 3.3.

After 2030, hydrogen will enable increasing flexibility in the electricity system, as storage and variable hydrogen production from electrolysis allows dispatchable power plants to run at peak times. The role of methane will diminish rapidly after 2030. Over the period through to 2050, the methane system will mainly provide flexibility in meeting demand for heating at peak times, such as through hybrid heat pumps. Collective heating systems require large-scale heat buffers and back-up facilities to cover cold spells. Back-up facilities can take the form of electric, methane or hydrogen boilers. This way, the underlying energy carriers play a key role in creating flexibility in the heat supply. See Section 3.3.

While some of the flexibility resources will be needed for only a limited number of hours per year (dozens to hundreds), they are still crucial in balancing the energy system, especially when it comes to the flexibility that provides extra energy to cover shortages. This shows that the desired number of flexibility resources and the desired security of supply are interdependent variables. See Section 3.3. Furthermore, the geographic spread and integration of flexibility resources within the Netherlands will require careful weighing of various aspects, such as the available space and effective utilisation of the available capacity in the energy transmission infrastructure. This is one of the topics that is addressed in greater depth in the *Programma Energiehoofdinfrastructuur* (PEH). See Section 3.5.

Having to amass a sizeable and diverse portfolio of flexibility resources in under thirty years is a major challenge. And there are also great uncertainties and fluctuations in the utilisation of the various flexibility resources. The expected number of operating hours of a flexibility resource can differ greatly depending on technical and economic features, on the development of other flexibility resources, on weather conditions and on developments in other countries. This is illustrated by two examples. First example: in order to make sure that sufficient power can be supplied even during very rare 'Dunkelflaute' situations, i.e. several consecutive days of unusual darkness and no wind in winter, around 7 GW of additional dispatchable power with limited operating hours would be needed, on top of the flexibility already assumed in the scenario, which includes 18 GW from power plants and dispatchable demand from industry. Second example: if industry turns out to be less flexible in its energy consumption than assumed, up to 10 GW of additional dispatchable power will be needed from other flexibility resources, such as battery storage or power plants (with limited operating hours). See Section 3.4.

Operational and strategic storage

In each of the scenarios that were analysed, energy storage plays a key role in balancing energy supply and demand along different time scales. This concerns both storage for the short to medium term, using batteries and heat, and long-term storage in the form of gases. The operational storage capacity needed for green gas in 2050 is between 1 and 12 TWh, while that needed for hydrogen is between 14 and 29 TWh, based on a year with an average weather profile. Based on the exploratory calculations for all weather profiles, a maximum storage capacity of 30 TWh will be needed for green gas in 2050. The Netherlands currently still has a natural gas storage capacity of more than 143 TWh. For hydrogen, the storage need will increase to a maximum of 60 TWh by 2050. Operational storage is intended to bridge the seasons and for short-cyclical storage. If seasonal green gas storage is primarily done using existing gas storage facilities for, and assuming that empty gas fields can also be used for seasonal hydrogen storage, a maximum of 70 caverns will be needed for green gas and hydrogen combined. Whether or not hydrogen storage in empty gas fields is actually an option is still being looked into. The Netherlands currently has six caverns in use for natural gas storage, and one is being developed for hydrogen. According to the Netherlands Organization for Applied Scientific Research (TNO), a maximum of 60 caverns can be created in the Netherlands by 2050, while Germany also has great potential in terms of existing and new caverns. See Section 5.4.

Alongside operational storage, the second edition of II3050 (II3050-2) examined how much strategic molecule storage capacity will be needed to cope with years with different weather profiles and cover the risk attached to importing energy. Depending on the scenario and weather profile, 35 to 59 TWh in strategic storage capacity will be needed, on top of the operational storage capacity. It may in the long term also be possible to use existing gas storage facilities in combination with a system that converts methane into (blue) hydrogen as a solution for strategic storage. See Section 5.4.

Energy infrastructure

Over the period between 2030 and 2050, network companies will continue to expand the electricity infrastructure and convert, expand and remove natural gas infrastructure. The following conclusions are relevant in this respect:

Electricity infrastructure

The four scenarios from the second edition of II3050 have an impact on TenneT's high-voltage grid to varying degrees. Further infrastructure expansion on top of the network expansions that TenneT has already planned through to 2035 will be needed for all voltage levels (110 kV to 380 kV) and in all regions. In terms of the space needed, expanding the EHV infrastructure will mean that the EHV grid will require between 20% and 33% more space than it currently occupies (in 2023). These are 380 kV overhead high-voltage cables with a length of roughly 1.5 to 2 times the distance between Amsterdam and Maastricht. See Section 5.4.

International transmission has a significant impact on the load on the EHV grid; international transmission depends on the available transmission capacity of networks outside the Netherlands and is influenced by domestic and EU energy policy. See Section 5.4.

Depending on the extent to which existing high-voltage substations can be expanded by adding one or two transformers, all scenarios forecast a need for an average of between 50 and 100 new HV substations (15-30% growth) by 2050, on top of the current number of substations in 2023. See Section 6.4. The capacity for these substations with the regional transmission network operators will at least have to be doubled or even tripled by 2050 to accommodate the increase in the peak load for both generation and consumption. See Section 7.4.

The regional network operators will start work in nearly every single neighbourhood, digging up streets to lay new cables and building new transformer substations. This is because the low-voltage network will have to be expanded by 20-30% in terms of cables compared to the current grid. In addition, the number of medium-voltage and low-voltage (MV and LV) transformer substations will have to be increased by 40-55%. The intermediate MV grid will also have to be expanded by 35-45%. See Section 7.4.

Curtailment of all solar power systems and the shortage-neutral connection of flexibility resources are essential steps in shaping the future grid as efficiently as possible. In this context, 'curtailment' means that extreme peak solar power production will not be fed into the power grid. Static curtailment (50-60%) prevents a need for additional infrastructure to accommodate large supply peaks that occur for a relatively small number of hours per year. 'Shortage-neutral connection' means that connecting flexibility resources will not lead to more capacity being required from the infrastructure. Flexibility resources will then be restricted for only a limited number of hours every year (under 200 hours). Otherwise, the infrastructure would have to be increased by 40-75%, while this additional capacity would, in fact, rarely be used. See Section 7.4.

Methane infrastructure

Despite falling demand and supply, all scenarios foresee that a main transport network with nationwide coverage for methane (currently natural gas, later green gas) will be needed until 2050 at least. This can be provided using the current natural gas infrastructure. Pipelines that are no longer needed can be repurposed for hydrogen transport or, for example, as collector or transport pipelines for green gas. Based on the pipelines available in 2040 and 2050, the two main gas quality categories, i.e. high-calorific and low-calorific gas, can still be maintained alongside each other. See Section 6.4.

The process of methanation, i.e. converting hydrogen into methane, was investigated as a way of simplifying the transition of the built environment to sustainability. This turns out to be a relatively costly alternative and, consequently, a socially undesirable solution on balance. See Section 10.4.

In all scenarios, a significant part of the regional gas grid in particular will fall into disuse: between 20% and 65% of the main low-pressure grid will no longer be needed. Removing this part of the gas grid will be a major undertaking and require a lot of execution capacity. In the International Trade scenario, most of the main low-pressure grid (80%) will continue to be used, but it will largely be repurposed for hydrogen transport. See Section 8.4.

In the scenarios, green gas production is widely dispersed across the country, meaning that green gas is often not produced near where there is demand for gas. Without additional measures in the gas networks, between 200 and 250 boosters will be needed to be able to use all the green gas produced. Combining green gas production with methane demand, expanding the number of network connections, using green gas collector pipelines, and clustering production are all ways to significantly reduce the need for boosters. See Section 8.4.

Other than during the winter months, there is a surplus of green gas in most areas, while there is peak demand during the winter months. That is why storage is needed. When storing on a national scale, boosting to the high-pressure gas grid (HPGG) will be required. This leads to questions about the required gas quality, because there is a difference in the requirements for green gas in the distribution networks and the requirements for the gas quality permitted for underground storage (such as the permitted oxygen and moisture content). See Section 8.4.

Hydrogen infrastructure

For a climate-neutral energy system in 2050, a new hydrogen supply chain will have to be developed from scratch over the coming decades. Key focus points for that are timely development, scale-up, and cost reduction (for electrolysers, for example), sufficient hydrogen storage volume, sufficient hydrogen availability worldwide, and a scale-up of the use of hydrogen for energy or feedstocks. The transport infrastructure required for hydrogen for 2050, on top of the current roll-out plan, turns out to be fairly robust: most of the measures are needed in all scenarios. That is despite major differences between the scenarios in the ratio of hydrogen production to hydrogen imports and in the amount of hydrogen storage required. See Section 6.3.

New hydrogen pipelines will be needed along some sections of the network, mainly to enable additional transport from west to east. Hydrogen compression will be required at multiple locations on the main national hydrogen network. Hydrogen compression can generally be built at existing natural gas compression sites, but this will not be enough. After 2030, hydrogen compression is also expected to be required at several new sites. Transporting hydrogen produced at sea using electrolysis will in all cases, from 2030, require an offshore hydrogen network that is connected to the network on land. See Section 6.3.

In each scenario, roughly 1,850 km of pipeline will have to be converted by 2050, of which 750 km after 2035. There is very little variation between the scenarios, due to the limited variation in the amount of transport capacity needed, but also because repurposed existing pipelines often have large diameters and will be overdimensioned. As early as in 2040, 200 of the aforementioned 750 km in repurposed pipelines will be needed. In each scenario, new hydrogen pipelines with a maximum length of 250 km will be needed after 2035 on top of the repurposed pipelines for the main network. See Section 6.3.

Variations on the scenarios show an additional challenge. Additional hydrogen flows on top of the maximum scenario will require an upgrade of pipelines to Belgium, while there is still transport capacity available for additional hydrogen flows to Germany. The latter will only require one additional compression site. In order to be able to cope with years with more severe weather profiles, approximately 90-150 km of pipeline will have to be upgraded, i.e. built new, and additional compression will be needed. See Section 6.5.

While repurposing parts of the regional natural gas distribution network for hydrogen is possible, it will involve a customised approach for each situation. It is important to make choices as to which industries to switch from methane to hydrogen, because both these gases can use the existing gas grid. It is generally not desirable to have parallel methane and hydrogen infrastructure in the target situation due to the complexity, safety issues, and the additional investments, work and space it would require. See Section 8.4.

Other infrastructure for CO_2 and heat

In order to cut carbon emissions in the Netherlands to below 10 Mt per year by 2050 in the scenarios of the second edition of II3050, CO_2 transport by pipeline to one or more storage facilities below the North Sea bed is one of the important solutions. See Section 9.4.

In the long term (towards 2050 and beyond), the CO_2 network can potentially be harnessed for negative CO_2 emissions or a circular economy, such as by transporting biogenic CO_2 to industrial clusters where it can be used to make products (such as plastics). The Dutch CO_2 infrastructure can be an international hub in this respect. See Section 9.4.

In each of the scenarios for 2050, collective heat grids play a much bigger role in supplying heat in the built environment than they do today. There are, however, differences between the scenarios, with the National Leadership scenario involving the largest transport volumes. Changes on the supply side will necessitate investment in relatively large-scale infrastructures for heat transmission to connect sources to one or more distribution networks. These transmission pipelines will, however, still always be on a regional scale. There is a great need for heat storage in all scenarios, with volumes of 4-11 TWh in 2040 and 3-14 TWh in 2050 for a year with a normal weather profile, whereby the National Leadership scenario involves the largest volumes. See Section 9.6.

Costs, space, feasibility and feedstocks

Costs

In the four 2050 scenarios, the national annual costs involved in the infrastructures for energy exceed today's energy system costs. Even without the energy transition, costs would start to rise considerably. The differences in total costs between the scenarios are minor, but cost composition does differ greatly between the scenarios. Most of the costs (over 50%) will go into modifying buildings, systems and production assets. The costs of infrastructure and flexibility resources (storage and conversion) represent 20-30% of the total costs of the energy system. Additionally, the European Integration and International Trade scenarios involve considerable costs for energy carriers because of the energy imports (20%) in these scenarios. These latter costs are sensitive to price fluctuations in the international market. See Section 11.2.

Space

The *estimation* of the space needed for solar fields and wind capacity differs between the various scenarios. Between 3,800 and 7,200 km^2 of space is needed for offshore wind power generation and between 1,250 and 2,500 km^2 for onshore wind power generation, while between 350 and 580 km^2 of space is needed for solar fields. The estimated space requirements vary between publications and largely depend on the exact indicators used. What is important is that these indicators keep changing over time: this has to be taken into account in comparisons with other – current and future – space requirement calculations. See Section 11.3.

Flexibility resources will require a lot of space in total. In the scenarios, large-scale batteries using today's technology will need 23-33 km^2 of space, which is comparable to the surface area of the municipality of Haarlem (its built-up area and outlying areas cover roughly 32 km^2). This is, in relative terms, a lot of space compared to infrastructure that takes up a comparable amount of space in terms of location and use of space. Compared to the space requirements of the new 110/150 kV substations, these flexibility resources will need 10 to 20 times more space. For onshore electrolysers, the requirement is 3–8 km^2. However, these space requirements for flexibility resources are dispersed over a large number of locations, meaning that regional integration is the primary concern. See Section 11.3.

The national electricity networks will have to be extended, which will require a lot of space. Expansion of the EHV grid will amount to between 320 km and 510 km of additional sections compared to the current EHV grid, which measures roughly 1,500 km. This covers an area of between 32 and 51 km^2. The space taken up by connections to the high-voltage grid (HV, 110/150 kV) will increase by approximately 555-955 km on top of the 4,400 km that this grid currently measures. These additional connections will take up between 19 and 33 km^2 of space. See Section 11.3.

The additional space that regional network operators will need above ground for the various types of stations amounts to between 4 and 6 km^2 (800 to 1,200 football pitches), of which – in most of the scenarios – approximately 1.2 km^2 for transformer substations. In most cases by far, these are areas in the built environment where it is likely to be difficult to find this extra space. Finding this space is a precondition for the success of the energy transition and a tough ask in a country as densely populated as the Netherlands. It mostly involves urban surroundings where, *on average*, one transformer substation will have to be added to every two transformer substations that are already there. See Section 11.3.

Depending on the scenario, laying new low-voltage and medium-voltage cables will require between 260 and 330 km^2 of additional underground space. Between 80,000 and nearly 105,000 km of cable will have to be laid in the ground. This equals 55% to 75% of the total length of all streets in the Netherlands. It will inevitably involve inconvenience for people; some of the routes are complex the cable laying will often require modifications to other infrastructures such as those for telecommunication and water. See Section 11.3.

The space needed for the national transport system for methane and hydrogen in 2050 is comparable to the space currently taken up by the national natural gas transport system, because the development pathway is based on the assumption that most of the existing gas pipelines and substation locations will be reused. For new pipelines and substations, too, the assumption is that these will be laid and built in the same locations as current pipelines and substations. See Section 11.3.

The storage of molecules in 2050, and hydrogen in particular, does have a spatial impact, especially underground. Creating the required caverns for hydrogen storage will lead to additional space having to be freed up temporarily above ground for salt leaching and brine discharge. The spatial impact can be limited if it proves possible to store hydrogen in empty gas fields, in offshore salt caverns, or in existing caverns in Germany. See Section 11.3.

The CO_2 transport infrastructure that may, depending on the scenario, be developed will largely run along the same routes as existing pipelines. The extra space needed is, therefore, minor. Things are different when it comes to the development of heat grids: the transport infrastructure to take heat from the source to the consumer will, in principle, consist of new pipelines, and laying heat distribution networks in districts will involve digging up numerous streets, for which space will be needed. See Section 11.3.

Feasibility

When it comes to electricity, there is the major task of scaling up in the relatively short term, mainly over the period covered by the current investment plans. We, therefore, strongly advise readers of II3050-2 to refer to these investment plans. The efforts for the high-voltage grid will initially be related to ongoing electrification, especially in industry, and to ensuring that regional network operators have access to sufficient capacity. Most of this development will take place up to 2035. Aside from that, work to connect offshore wind power and international connections to the DC network will go on beyond 2040. For regional network operators, the pressure on the low-voltage network will be greatest over the period up to 2035. While the challenge with respect to the medium-voltage network is also considerable, it is spread out over a longer period of time. As regards the regional power grids, the required network expansion is at a pace that is two to three times faster than the current (accelerated) pace. For the national gas infrastructure, too, the main part of the work will have to be done over the period through to 2035. Repurposing gas pipelines for the main infrastructure for hydrogen constitutes the bulk of this work. After 2035, the work will shift to the offshore hydrogen network and to increasing hydrogen storage capacity. See Section 11.4.

The issue that the regional gas networks face is mainly to accommodate the feed-in of green gas in the short term. The bulk of the work for the regional gas networks will be done after 2035, due to the conversion to hydrogen and also the removal of networks in districts that will be switched fully to electricity or heat. See Section 11.4.

Feedstocks

It almost seems inevitable that soaring demand for feedstocks, especially for certain types of metals, will already lead to scarcity and even shortages in the coming years. According to the IEA, global demand for metals such as copper, lithium, cobalt and nickel will exceed supply before 2030. This will affect all parts of the energy system, and battery systems in particular. It will slow down the energy transition and is certain to lead to a (sharp) rise in the costs involved. See Section 11.5.

The top 10 of critical metals is basically the same regardless of the scenario. Lithium, which is used virtually exclusively for battery systems, is top of the list with annual demand over the 2040-2050 period exceeding one quarter of the world's total lithium production in 2020, depending on the scenario. Over the 2030-2040 period, this figure will already be 4% on average every year. After lithium, dysprosium and neodymium are further critical feedstocks. These are needed primarily for wind turbines and battery systems. The scenarios contain very different projections for each of the metals, differing by a factor of up to approximately 1.5. Promoting rethink, reduce, reuse, and recycle (the strategies from the National Circular Economy Programme) can significantly bring down demand, by as much as 90% for some metals. See Section 11.5.

Production capacity for the required materials and equipment needs to be scaled up enormously. Examples are the production of electrolysers, power transformers and wind turbine towers, but also ships for hydrogen or ammonia imports. This is also expected to become a serious bottleneck. Investment will have to be stepped up significantly in almost all areas. It is difficult to get a good idea of the extent of the investment required.
The situation differs for semi-finished and finished products, and the value chains are complex and opaque.
See Section 11.5.

Finally...

The Netherlands can be climate-neutral by 2050. This second edition of the Integrated Infrastructure Outlook for the 2030-2050 period shows what is needed to create the energy system of the future. But it also shows that, on top of the work already being done and the developments that have already been planned, many additional steps need to be taken in the short term to actually achieve climate neutrality by 2050.

Chapter 1

Introduction

Making the Netherlands climate-neutral by 2050 is a major challenge, but it can be done. This outlook outlines four climate-neutral energy systems and their corresponding development pathways for flexibility resources and energy infrastructure. Climate neutrality for the Netherlands not only requires a rapid phase-out of fossil energy, but also a rapid increase in the production of energy from renewable sources. This involves not only a large-scale transformation of industry in terms of the energy and feedstocks used, but also the roll-out of more and more charging infrastructure for electric vehicles and replacement of all fossil-fuel vehicles with zero-emission vehicles. In the built environment, climate neutrality means insulating the majority of houses and other buildings and switching to a sustainable heat supply through heat grids in large parts of the Netherlands, including for the horticulture sector. Entirely new facilities will also be needed for production of synthetic aviation and shipping fuel, as well as for flexibility resources and storage to ensure sufficient energy supply throughout the year. All these developments require a large-scale overhaul of existing infrastructure or the building of new infrastructure.
This report is all about exploring the development pathways for flexibility resources and infrastructure.

The overhaul of the existing energy infrastructure between today and 2050 has to ensure that future supply and demand of renewable energy can be balanced with a high level of reliability at all times. This way, the infrastructure will enable a climate-neutral energy system. Given the major importance for society, national and regional network operators jointly took the initiative for a second edition of the Integrated Infrastructure Outlook for the 2030-2050 period (II3050-2). A second edition became necessary mainly in view of the rapid developments in policy and the energy landscape over the past years, including internationally. This report constitutes an update to the first II3050 edition from 2021 (II3050-1) and goes into greater depth on certain matters. The first update of the scenarios, the II3050 scenarios, was published in June 2023.

Certain results from this outlook have already been used as input for the National Energy System Plan and other national programmes, such as the *Programma Energiehoofdinfrastructuur* (PEH) and the *Verbindingen Aanlanding Wind Op Zee* (VAWOZ), which are run by the Dutch Ministry of Economic Affairs and Climate Policy to provide further direction for government policy.

The objective of the Integrated Infrastructure Outlook is to develop the kind of insight into the energy infrastructure, flexibility resources and system integration that is needed to be able to build a reliable, effective and robust climate-neutral energy system by 2050. The outlook therefore outlines development pathways for flexibility and infrastructure, along with future-proof developments and important decision points. With this in mind, relevant stakeholders were involved and the outlook ties in with regional developments in energy generation from renewable sources, how demand may develop in different sectors, and targets from the Climate Agreement.

This infrastructure outlook is intended as input for network operators’ analysis of the long-term impact that various developments will or may have on the energy infrastructure and to help them identify, at an early stage, relevant factors during the transition towards a climate-neutral energy system. This second edition of II3050 can, therefore, also serve as a guideline for various stakeholders such as market parties and provide government bodies with information as input for their policy-making processes. The Integrated Infrastructure Outlook focuses specifically on the 2030-2050 period, i.e. the period largely beyond network operators’ current investment plans. Unlike these investment plans, this outlook does not define specific infrastructure measures or the associated investments.

The outlook is based on the assumption that the climate ambitions for 2030 and 2035 will be realised and that the investment plans will be implemented. The network operators’ investments through to 2035 are detailed in the various 2024 investments plans drawn up by the network operators, as published in November 2023.

1.1 Approach for the final II3050 report

The study that led to the final report of this II3050-2 was conducted in three phases. The first phase involved updating the four climate-neutral energy scenarios for 2050. The second involved mapping the impact of these scenarios for 2050 on the infrastructures. The third phase was devoted to outlining the development pathway between 2030 and 2050.

- **Phase 1: Climate-Neutral Energy Scenarios for 2050**

In the first phase, the four climate-neutral energy scenarios were developed. This phase was wrapped up in June 2023 with the publication of a report entitled ‘The Energy System of the Future: the II3050 Scenarios'. These scenarios were developed by experts from the network operators, which involved broad consultation of stakeholders that included companies, government bodies, science institutions, and trade associations.

It is unknown what society will look like thirty years from now and how technology will develop. Nor is there certainty on the choices that are yet to be made in the energy transition. This is why four scenarios have been worked out, with each one describing what a climate-neutral energy system could look like in 2050, assuming highly divergent infrastructure needs. These scenarios were subsequently analysed in terms of their regional impact: energy supply and demand, as well as all the flexibility resources, were plotted on a map of the Netherlands. This is necessary to be able to perform the infrastructure analyses: the choice of location for supply, demand and flexibility determines to a great degree what infrastructure will be required. This makes the scenarios a tool to analyse infrastructure needs given the certainties and uncertainties as they are today.

- **Phase 2: Impact on infrastructures**

In the second phase, the focus was on analysing the impact that the scenario developments will have on the energy infrastructure for 2050 and on analysing the changes to the infrastructure needed to prevent bottlenecks. This began with an analysis of energy supply and demand on an hour-by-hour basis. This analysis shows when supply and demand are not balanced and, consequently, what degree of flexibility is needed. The question that follows is how to ensure that the energy supply side, through the effective use of flexibility resources, can always meet the requirement of energy balance: keeping the lights on, keeping houses warm, keeping businesses running, and ensuring optimum use of the available supply of energy from renewable sources. To address this question, the analysis focused on the potential contributions of the various flexibility resources, such as conversions between energy carriers, storage of heat, electrons, or molecules, and import or export. The final step in this phase consisted of conducting calculations for the infrastructure for electricity, methane, hydrogen, heat and CO_2, the subsequent analyses of which show where the bottlenecks are and what causes them. These analyses also provide an idea of possible solutions, showing implications in terms of costs, space, feasibility and resources. Feasibility focuses mainly on the required human resources and lead times for the modification and expansion of the infrastructure. The impact in terms of costs, space and resources is shown for complete energy value chains, from supply to demand including infrastructure.

- **Phase 3: Infrastructure development pathways between 2030 and 2050**

The third phase, which was completed in September 2023, addressed the overarching objective of II3050: to outline development pathways for infrastructure, including identifying where measures are needed, where choices have to be made, and when the key decision points are (i.e. when choices have to be made by, given the time it takes to develop infrastructure). Bottlenecks may be caused by factors such as the government being too late in making decisions, engineering staff shortages, lack of physical space, or overly long lead times for infrastructure modifications.

1.2 Input from stakeholders and relationship with adjacent projects

Commonalities and differences between II3050 and investment plans

II3050 and other outlooks, exploratory studies or visions on energy systems are not used as a basis for investments in infrastructures. The process of drawing up investment plans (IPs) always involves detailed research to be able to make the right specific infrastructure choices. The focus for the outlook in II3050 is, therefore, on analysing and considering possible developments and their potential impact in the long term. The outlooks offer perspective and a basis for assessment of the investment plans from the investment planning process against the scenario scope. Assessment of the investment plans for the short to medium term against the development pathways for the long term tells us how future-proof they are. II3050 seeks to determine the extent of the future infrastructure challenge based on different assumptions and explores possible development options. The insights from this outlook will help network operators meet the challenge of guaranteeing a reliable energy system in the longer term as well.

1.3 Document arrangement

Each chapter starts with the conclusions in the first section, followed by a brief description of a number of methodological aspects and – in closing – the results. The appendices provide further depth, tables and figures that, for reasons of readability, were not included in the body of the final report for II3050-2.

The processes and methods used in the first edition of II3050 have been kept the same in the second edition of II3050 where possible, partly for the purpose of comparability and consistency. The paragraphs describing these methods and processes are therefore identical to those in the first edition.

This report consists of three parts:

1. Scenarios and the energy system

The first part goes into greater depth on the scenarios and how the energy system works. Besides summarising the climate-neutral energy scenarios for 2050 and their regional breakdown, this part addresses several system issues and the role of flexibility resources in the energy system.

2. Infrastructure up to 2050

The second part describes the impact of the scenarios on the infrastructure in 2050 and the development pathways to get us there. While a distinction is made between national and regional infrastructure, between the infrastructure for electricity, methane and hydrogen, and between other infrastructure for CO_2 and heat, this part does also specifically look at an integrated approach for all these infrastructures combined.

3. Impact on costs, space, feasibility and feedstocks

The third part goes into the impact of the scenarios and the infrastructure developments on the overarching topics of costs, space and feasibility, and looks at the resources situation in relation to the transformation of the energy system.

Part 1

Scenarios and the energy system

Chapter 2

Climate-neutral energy scenarios for 2050

This chapter summarises and elaborates on the climate-neutral energy scenarios that were presented in ***The Energy System of the Future: the II3050 Scenarios (Netbeheer Nederland, June 2023)***.

Section 2.1 goes into the scenario framework, what has changed compared to the first edition of II3050 and the main points of each scenario, with an overview of the scenario quantification. Section 2.2 looks at the regional impact and the link to the energy infrastructure. This chapter ends with several key system issues in Section 2.3 to add further depth to the scenarios, looking at carbon needs, production of synthetic feedstocks and fuels, and a zero-CO_2 electricity system in 2035.

Conclusions on system issues

For the first time, II3050 looks not only at the energy system in detail, but also at the carbon issue. In 2050, there will still be a need for plastics, chemicals and (carbonated) foodstuffs. This means that renewable sources of carbon for these products will have to be found in the future, and it means that CO_2 capture and recycling will be needed in places where fossil carbon is still used. For plastics made from petroleum, for example, this means that they need to be recycled fully after use, or, if that is no longer possible, that the CO_2 will have to be captured during waste incineration and reused as a feedstock. A downside to this is that circular use of materials and substances can only meet a limited proportion of the carbon demand for production processes and that the circular processes require a lot of energy and space. There are also new technologies that can be used to capture carbon from the air (Direct Air Capture), but it is as yet unclear how feasible this is. In the Netherlands, the shortage of renewable carbon leads to an allocation issue: what use of renewable carbon would be the wisest choice given the many applications that could benefit from it? Where does the use of renewable carbon create the most value? And is that also the choice society makes? See Section 2.3.1.

Besides large volumes of energy, the production of synthetic fuels and feedstocks will require renewable carbon. How much synthetic fuels and feedstocks the Netherlands will be producing in 2050 remains to be seen. Obviously, the question of how much energy-intensive industry – having become sustainable – will still exist in the Netherlands, has a major impact on the extent of the infrastructure and flexibility resources that will be needed, including dispatchable power plants, conversion and storage. Increased production will have an adverse impact on the business case for electrolysis and power-to-heat plants (fewer operating hours). The business case for power plants will, however, improve (more operating hours) and more hydrogen storage will be needed to keep the plants running. Extensive production of renewable energy combined with relatively limited manufacturing of synthetic products means, however, that more electricity will be transported to other countries on an ongoing basis, which will require considerably more infrastructure. The Netherlands will have to weigh the pros and cons of production of synthetic products and other energy-intensive industrial processes within its borders.
See Section 2.3.2.

Additionally, there is also the ambition to create a zero-CO_2 electricity system by 2035, as announced recently in the 2050 Energy System Outlook. This ambition was not yet incorporated in the 2024 IP scenarios, which are also used in this outlook. How does this ambition impact on II3050? Bringing forward the target of having a fully zero-CO_2 electricity system is expected to require even more rapid scaling up of infrastructure, hydrogen production, imports and storage, renewable generation, efficient energy use, and flexibility in the form of conversion, storage and demand response. Over the period through to 2035, this will put even greater pressure on costs, space, feasibility and feedstocks. In addition, it cannot be ruled out that such an accelerated approach will have an adverse impact on the energy transition in other sectors. See Section 2.3.3.

2.1 The climate-neutral energy scenarios for 2050

The Netherlands is currently working hard to build the sustainable and climate-neutral energy system of the future. This is a complex transition that involves countless changes in the economy and society. The II3050 scenarios describe four different visions for the future and transition pathways for the energy system, whereby each scenario has a different impact on the energy infrastructure. This means that the scenarios help provide clarity on the infrastructure challenge and how it relates to society's energy system choices that have yet to be made, and are, therefore, still uncertain. In making these choices, it will obviously be helpful to have a clear idea of the association between energy system choices and the infrastructure challenge. The scenario framework is centred not only on the major energy system choices, but also on the main uncertainties in the energy and feedstock transition.

The scenario framework from the first edition of II3050 has largely been maintained in this second edition of II3050. It has, however, been recalibrated based on insights from the past period (including the new climate targets). The scenarios differ from each other in the extent to which the government controls developments and makes choices or allows scope for the free operation of market forces in the energy market. Equally, the energy transition can be organised either on a more domestic (national or regional) scale or on an international scale. In addition, the various sectors' choices as to what technologies and energy carriers they use affects what the energy system will ultimately look like.
The scenarios are made up of a combination of these factors. This leads to the following four scenarios: Decentral Initiatives (DEC), National Leadership (NAT), European Integration (EUR), and International Trade (INT).
The scenarios are detailed further in Figure 1.

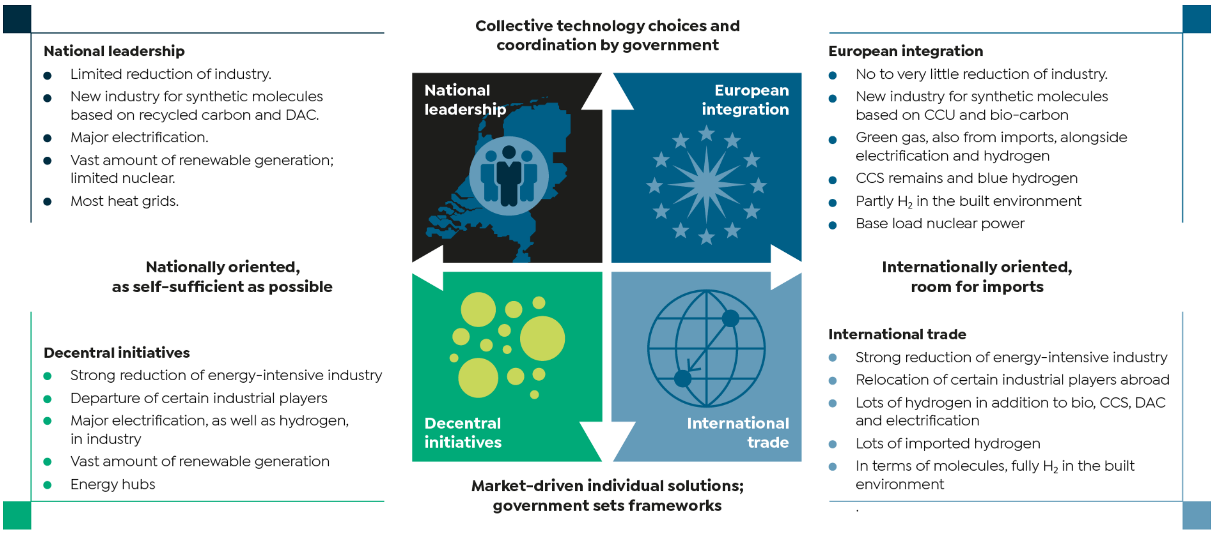

Figure 1: *II3050-2 scenario framework: the features and assumptions of the four scenarios for climate neutrality. Besides the features listed here, a large number of aspects of the energy system are considered to be changeable. These are specific energy system choices or major uncertainties in terms of demographics, the economy and the environment, social developments, technology and political or governance aspects. For full and extensive details of the scenarios, see the interim report:* ***The Energy System of the Future: the II3050 Scenarios (Netbeheer Nederland, June 2023)****.*

2.1.1 Changes in the scenarios

Since publication of the first edition of II3050 in April 2021, a large number of developments have occurred within a short time span that affect the transition. The following developments were taken into account in updating the II3050 scenarios:

- The EU presented its Green Deal with the Fit for 55 programme.
- The Dutch national greenhouse gas emission reduction targets were tightened significantly, going from 49% emission reduction at the time of the 2019 Climate Agreement to at least 55% with an ambitious policy programme to reduce emissions by 60%.
- The government has decided to keep the Borssele nuclear plant open for longer and to build new nuclear plants.
- The government intends to develop and bring to the shore 10 GW of additional offshore wind power by 2030.
- Industry has made cluster-based plans for the transition to sustainability, the so-called Cluster Energy Strategies (CES), which feed into a national programme for the energy transition in industry (PIDI/NPVI/MIEK).
- The Russian invasion of Ukraine and resulting war has sent shock waves through the European energy market. This has affected awareness of a number of issues and the associated sense of urgency, including awareness of the importance of security of supply and, with that, the importance of more ambitious plans for greater self-sufficiency and to accelerate the move towards sustainability (REPowerEU), with prolonged impact on import terminals, gas storage, and the production of energy from renewable sources by consumers and companies.

Incorporating feedback on II3050-1 and adjacent policy processes

The scenarios from II3050-1 generated feedback. The following points from this feedback have been incorporated into this second edition of II3050:

- Go into greater depth on market segments and planning processes. This includes provincial system studies, sectoral plans such as the Dutch National Charging Infrastructure Agenda (NCIA), Regional Energy Strategies (RES), Cluster Energy Strategies (CES), Dutch Transition Visions for Heating (TVH), Offshore Wind Landfall Foresight Study (OWLFS), National Hydrogen Programme (NHP), etc.
- Abandon the predefined general growth or shrinkage projections for industry, mobility and other sectors as a key point of differentiation between the scenarios. Instead, specific input has now been incorporated into the scenarios.
- Go into greater depth on flexibility: gain a clearer idea of the various possible ways to resolve the hour-to-hour imbalance between energy supply and demand using flexibility resources.

- Get fresh perspectives (external experts) on board. This is to challenge the network operators' scenario storylines and prevent tunnel vision.

- Increase stakeholder involvement: take input from sector representatives into account more and create scope for discussions of interim results by organising a large number of stakeholder sessions, supplemented with sessions focusing on specific sectors/topics and one-on-one interviews with experts.

- Go into greater depth on industry: improve the data backing up the modelling of the transition for industry by collecting specific input from the fourteen largest industrial companies (G14) and six industry clusters (C6).

Updates to network operators' investment plans (2024 IP scenarios)
The network operators have updated their scenarios for the 2025-2035 period for the purposes of their investment plans. The 2024 IP scenarios outline the possible developments through to 2035 and form the starting point for the second edition of II3050.

- The 2024 IP scenarios paint a picture of what the further transition towards 2050 could look like. Within that transition, the period between 2030 and 2040 is a crucial phase during which timely system choices will have to be made and infrastructure development pathways will have to be charted towards a fully climate-neutral Netherlands.

- The regional breakdown of the scenarios was updated to ensure they tie in with the various planning processes and the working methods that network operators currently use for things such as integrated programming or preparing investments.

2.1.2 Scenarios in outline

Brief descriptions of the scenarios. For more detailed information, see ***The Energy System of the Future: the II3050 Scenarios (Netbeheer Nederland, June 2023).***

The storylines of the four scenarios sketch a picture of the Netherlands; how society will change and how decisions on energy are made. An energy flow chart in the form of a so-called Sankey diagram subsequently shows the main energy flows and conversions. This shows for the main energy flows or energy carriers the sectors in which they are used and how these energy flows or energy carriers relate to each other. In the charts, energy mostly flows from the left (primary energy sources) to the right (the demand sectors). The thickness of the connecting lines shows the amount of energy flowing over a full simulated year. The line reflects the total volume and not the capacity.[1] Energy losses are also shown. Finally, statistics are shown for widely used parameters, such as energy use, production of energy from renewable sources, flexibility and the impact on greenhouse gas emission reduction.

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[1] In this report, we use the term 'volume' to denote an annual quantity of energy (in joules, for example). By 'capacity', we mean energetic power (such as watts). Both units are of crucial importance for the functioning of the energy system and for security of supply.

Decentral Initiatives scenario (DEC)

The Netherlands targets regional action by supporting private-sector business cases for climate-neutral technologies. Citizens and local communities have a large degree of autonomy and make their own choices in the energy transition. Some citizens choose the most economical solutions, while others are guided by idealistic motives. Consumers and companies are incentivised in various ways to make sustainable choices. Local governments do this through, for example, information and financial incentives. Numerous local initiatives emerge from progressive citizen collectives and companies, making the most of the available local sources. Onshore solar and wind power generation have grown enormously. Industry transitions towards more use of bio-based and circular feedstocks. Owing to the large-scale availability of renewable energy (as variable supply), there is limited acceptance of CCS. Additionally, there is limited focus on the transition of the energy-intensive basic industry and on energy sources for that industry. As a result, part of that industry ceases operations in the Netherlands. Heating in the built environment is provided using a mix of technologies and from various locally available sources, such as geothermal heat, heat pumps, ground-coupled heat exchangers, green hydrogen and green gas.

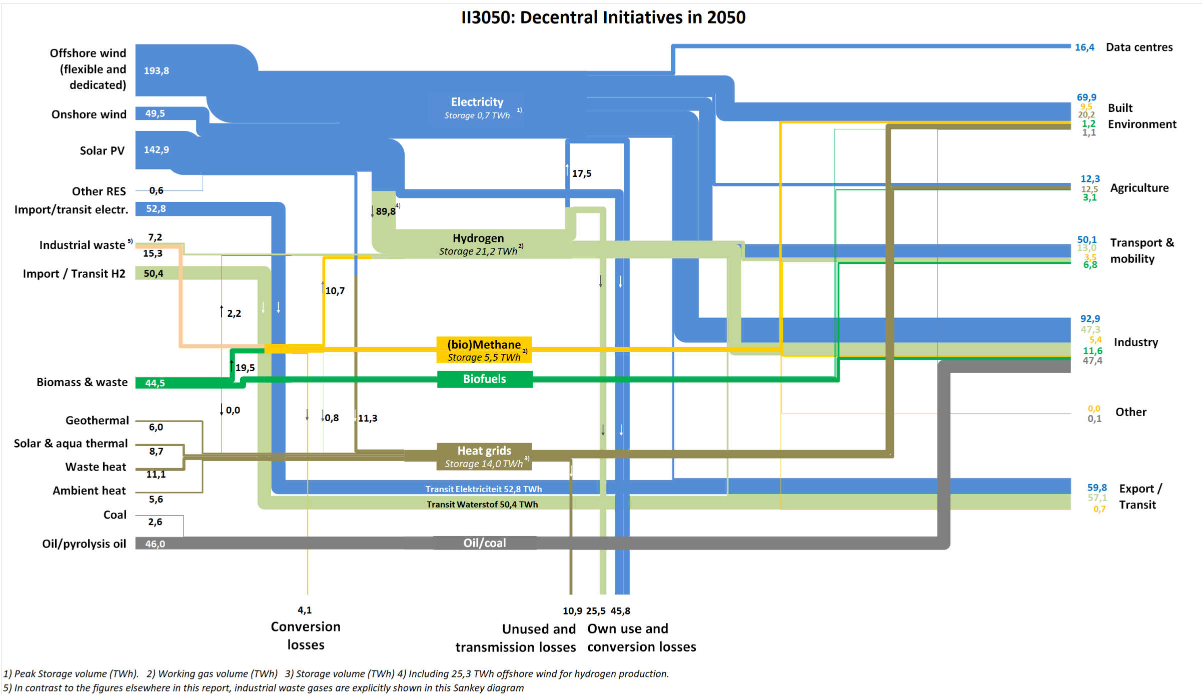


Figure 2: *Energy flows in the DEC scenario*

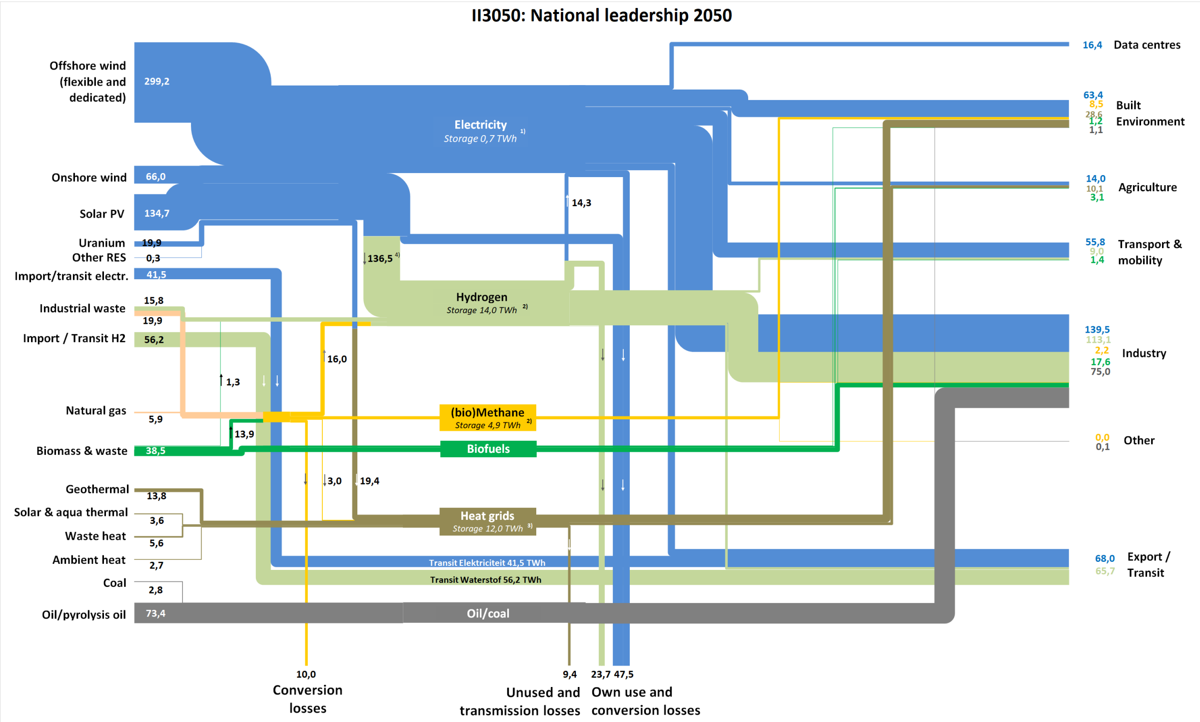
Table 1: *Key energy-system figures in the Decentral Initiatives scenario, in 2050*

Energy use (final total incl. non-energetic)		Flexibility	
Reduction in final energy	44%	Batteries	70 GW / 0.7 TWh
% renewable energy	86%	Power to gas; H_2 storage	33 GW / 11 TWh
Degree of self-sufficiency	94%	Power to heat; Heat storage	11 GW / 13 TWh
Share of electrification	61%	Interconnection	18.8 GW
Share of hydrogen	15%	Dispatchable power	20 GW
Share of biomass	10%		
Energy production from renewable sources		**CO_2 and carbon (total incl. LULUCF)[2]**	
Offshore wind	45 GW	Emission reduction by 2040	83%
Solar PV	183 GW	Emission reduction by 2050	96%
Onshore wind	15 GW	Carbon use by industry	20 Mt C

2 greenhouse gas-equivalent emissions from Land Use, Land-Use Change and Forestry

National Leadership scenario (NAT)

The Netherlands targets an energetically efficient system within the scope of what is possible in the Netherlands and works on a national level to determine the energy mix, including what sources are used and the extent of energy generation within the Netherlands. In doing so, government bodies choose the technologies that will be used in the Netherlands. To this end, the Dutch government draws up obligatory policy and regulations, while also participating financially in projects that are deemed to be of national importance. The government promotes the development of new industries, including for synthetic fuel production, and incentivises electrification of existing industry. In the built environment, government coordination through a district-based obligational approach drives the development of heat grids that run mainly on residual heat, geothermal heat and flexible electrical sources, such as power-to-heat plants. Large-scale national energy supply projects are launched, including projects to make the most of the potential of offshore wind power and several projects for flexible nuclear plants. Additionally, green hydrogen plays a key role in balancing the electricity system, for the supply of high-temperature heat in industry, and as a feedstock.



1) Peak Storage volume (TWh). 2) Working gas volume (TWh). 3) Storage volume (TWh,4) Including 63,4 TWh offshore wind for hydrogen production.
5) In contrast to the figures elsewhere in this report, industrial waste gases are explicitly shown in this Sankey diagram

Figure 3: *Energy flows in the National Leadership scenario (NAT).*

Table: 2: *Key energy system figures in the National Leadership scenario in 2050.*

Energy use (final total incl. non-energetic)		Flexibility	
Reduction in final energy	26%	Batteries	60 GW / 0.7 TWh
% renewable energy	84%	Power to gas; H_2 storage	45 GW / 14 TWh
Degree of self-sufficiency	89%	Power to heat; Heat storage	11 GW / 11 TWh
Share of electrification	56%	Interconnection	18.8 GW
Share of hydrogen	23%	Dispatchable power	18 GW
Share of biomass	6%		
Energy production from renewable sources		**CO_2 and carbon (total incl. LULUCF)**	
Offshore wind	72 GW	Emission reduction by 2040	82%
Solar power	173 GW	Emission reduction by 2050	96%
Onshore wind	20 GW	Carbon use by industry	27 Mt C

European Integration scenario (EUR)

The Netherlands targets an integrated and efficient European energy system: countries mutually align their energy policy and use each other's energy sources. Europe works on a joint energy policy and wants to be more independent. Green gas is produced on a large scale in Europe and, consequently, used in various sectors. There is strong growth in solar and wind energy combined with significant use of nuclear energy. The potential for offshore wind power in the North Sea is harnessed well in collaboration with other countries that border the North Sea. Industry becomes more sustainable through electrification and the use of European biomass and hydrogen as a fuel and feedstock. CCS is used on a large scale, including for energy generation with negative emissions (BECCS[3]) and for blue hydrogen production, but also for CO_2 capture from fossil sources. Besides large volumes of renewable feedstocks/molecules, supplemented with feedstocks from recycling (pyrolysis oil), small volumes of new fossil feedstocks are used. CO_2 from surrounding countries is also stored in the Netherlands. Efforts to move the built environment towards sustainability revolve around district-based courses of action and there is tight coordination of the development of cross-regional heat grids. The combination of heat grids and hybrid heat supply in buildings provides a moderate peak in electricity demand during cold spells. Significant expansion of pan-European charging infrastructure networks and high-speed rail networks ensures radical electrification of transport and mobility.

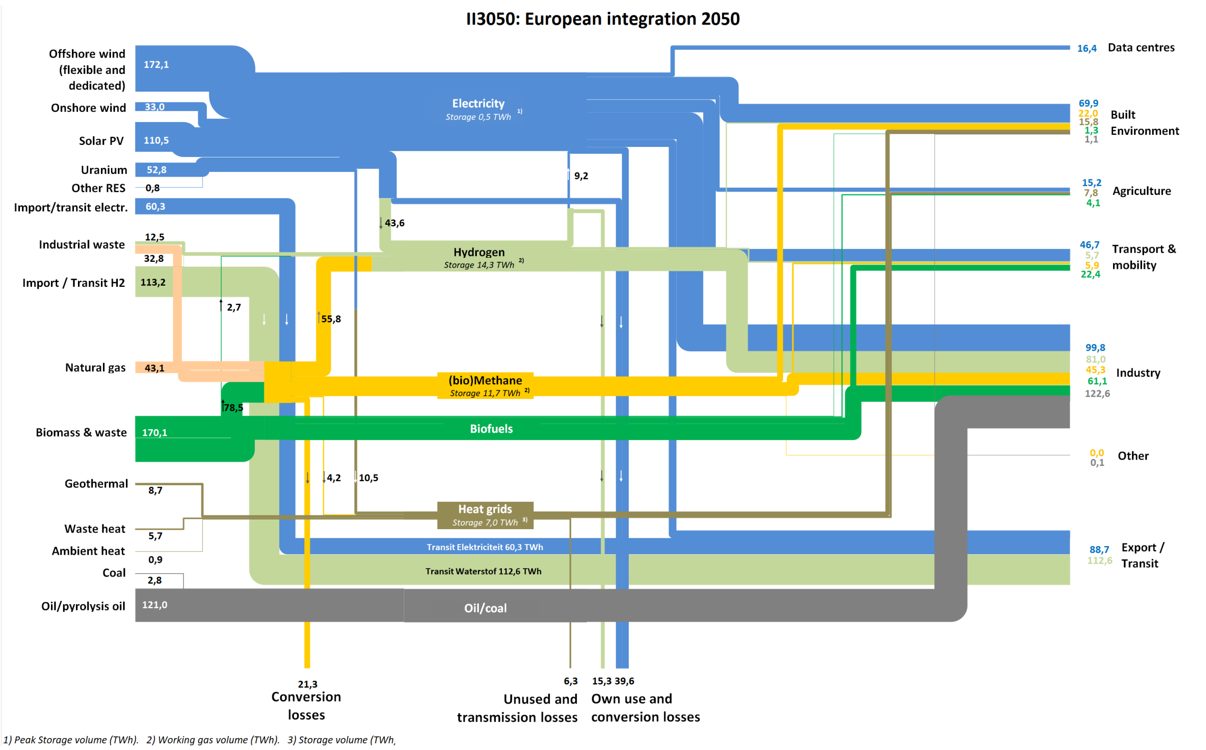


Figure 4: *Energy flows in the European Integration scenario (EUR)*

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3 Bio-energy with CCS

Table 3: *Key energy system figures in the European Integration scenario in 2050.*

Energy use (final total incl. non-energetic)		Flexibility	
Reduction of final energy	14%	Batteries	39 GW / 0.5 TWh
% renewable energy	74%	Power to gas; H_2 storage	16 GW / 14 TWh
Degree of self-sufficiency	46%	Power to heat; Heat storage	6 GW / 7 TWh
Share of electrification	42%	Interconnection	28.8 GW
Share of hydrogen	15%	Dispatchable power	19 GW
Share of biomass	27%		
Energy production from renewable sources		**CO_2 and carbon (total incl. LULUCF)**	
Offshore wind	38 GW	Emission reduction by 2040	80%
Solar PV	126 GW	Emission reduction by 2050	96%
Onshore wind	10 GW	Carbon use by industry	51 Mt C

International Trade scenario (INT)

The Netherlands targets development of its economy by making the most of international worldwide energy and feedstock supply chains. Making strategic, maximum use of international energy and feedstock markets, the Netherlands scours the global market for options with the lowest cost. Global free trade plays a key role in this respect. The market is stimulated through supporting general incentives, subsidies and CO_2 pricing. Partly because of this, Dutch companies, too, can do their bit to make the supply chain sustainable. Hydrogen and other climate-neutral energy carriers are imported from countries with relatively favourable conditions for the production of these resources. The Netherlands becomes a transit country for hydrogen and hydrogen products. Individual transition pathways are the preferred method for making the built environment sustainable, with less use of green gas but extensive use of hybrid heat supply combined with hydrogen. Industry becomes more sustainable through electrification and the use of hydrogen, also as a feedstock. Due to the advent of global trading chains, part of the energy-intensive industry relocates abroad. Instead, more semi-finished products are imported for further processing in the Netherlands. The Netherlands also commits to green hydrogen production using offshore wind power. However, due to the high energy imports, the Netherlands has to produce less itself.

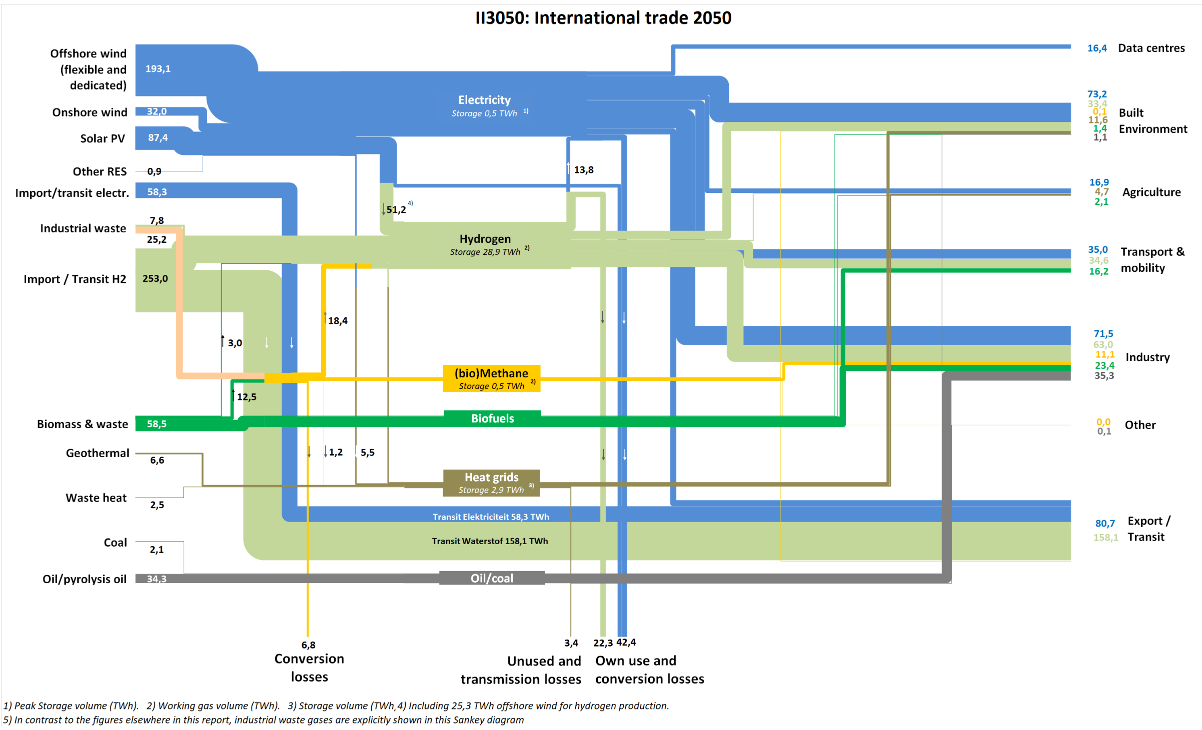

Figure 5: *Energy flows in the International Trade scenario (INT).*

Table 4: *Key energy system figures in the International Trade scenario in 2050.*

Energy use (final total incl. non-energetic)		Flexibility	
Reduction in final energy	35%	Batteries	41 GW / 0.5 TWh
% renewable energy	68%	Power to gas; H_2 storage	18 GW / 29 TWh
Degree of self-sufficiency	72%	Power to heat; Heat storage	3 GW / 3 TWh
Share of electrification	47%	Interconnection	28.8 GW
Share of hydrogen	29%	Dispatchable power	15 GW
Share of biomass	12%		
Energy production from renewable sources		**CO_2 and carbon (total incl. LULUCF)**	
Offshore wind	46 GW	Emission reduction by 2040	83%
Solar power	100 GW	Emission reduction by 2050	96%
Onshore wind	10 GW	Carbon use by industry	38 Mt C

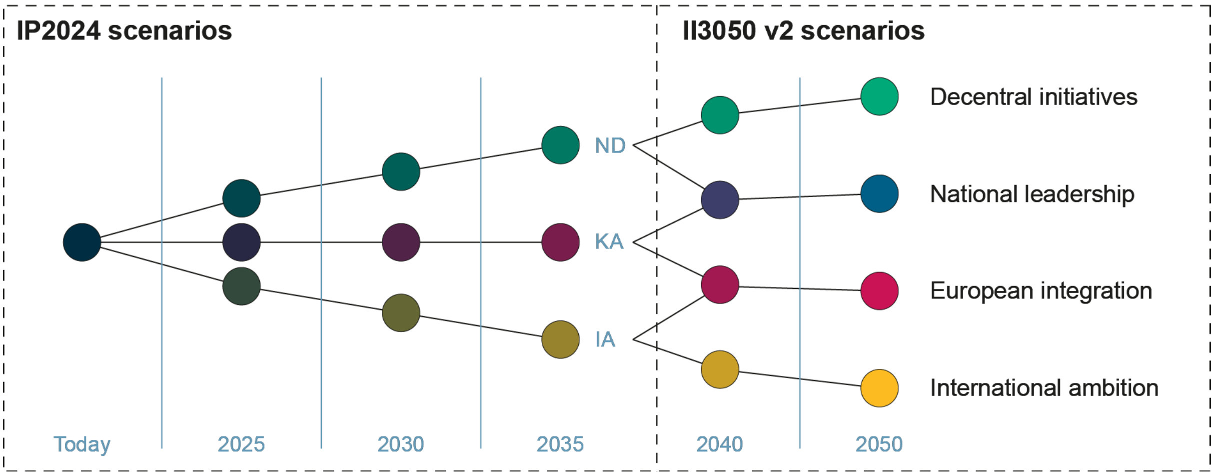

Figure 6: *Interrelationship between the scenarios for 2024 IP and the final pictures for II3050-2.*

The detailed scenarios are also included in the Energy Transition Model (ETM); see Appendix B.

2.1.3 Scenario quantification table

Table 5 provides the main indicators and outcomes from the scenarios, using 2019 as the relevant 'reasonable normal' reference year (pre-COVID, pre-Ukraine war). The figures for 2030 were calculated in the scenarios used in the 2024 IP.[4] In the 2024 IP, the scenarios are called Climate Ambition (KA), National Driver (ND), and International Ambition (IA). The figures for 2035 and 2040 are provided in Appendix A.

Table 5: *List of the main indicators of II3050-2.*

			2019	2030			2050			
			Ref.	KA	ND	IA	DEC	NAT	EUR	INT
Demand	Electricity demand (final and flexible)[5]	TWh	119	184	233	170	364	433	339	269
	of which Built environment	TWh	56.0	52.1	52.3	52.5	69.9	63.4	69.9	73.2
	of which Mobility	TWh	2.4	18.5	25.6	12.8	50.1	55.8	46.7	35.0
	of which Industry	TWh	41.3	54.1	63.5	47.5	92.9	139.5	99.8	71.5
	of which Agriculture, IT, energy	TWh	19.0	25.8	30.6	24.4	32.4	33.8	39.4	39.1
	of which Flexible: P2X and storage	TWh	0.0	33.2	61.4	32.7	118.3	140.1	83.5	50.6
	Methane demand (final and flexible)	TWh	374	238.8	209.1	235.7	18.6	15.5	120.6	12.0
	of which Built environment	TWh	109	73.5	67.7	82.0	9.5	8.5	22.0	0.1
	of which Mobility	TWh	1	0.0	0.0	0.3	3.5	0.0	5.9	0.0
	of which Industry	TWh	104	88.5	73.8	82.0	4.4	3.8	87.4	10.6
	of which Agriculture	TWh	10.5	4.5	2.2	4.6	0.0	0.0	0.0	0.0
	of which Flexible: power plants and peak boilers	TWh	150.5	72.2	65.3	66.7	1.1	3.2	5.3	1.3
	Hydrogen demand (final and flexible)	TWh	0.0	47.8	47.7	60.8	102.2	159.4	114.1	173.6
	of which Built environment	TWh	0.0	0.0	0.0	0.0	0.0	0.0	4.1	33.4
	of which Mobility	TWh	0.0	3.7	2.1	7.9	13.0	9.0	5.7	34.6
	of which Industry	TWh	0.0	44.1	43.3	48.0	47.3	113.1	81.0	63.0
	of which Agriculture	TWh	0.0	0.0	0.0	1.2	0.0	0.0	0.0	3.5
	of which Flexible: power plants and peak boilers	TWh	0.0	0.0	2.3	3.6	41.9	37.4	23.3	39.2
Production	Wind power	GW	4	31	32	31	60	92	48	56
	of which onshore	GW	3.5	9.1	10.3	7.5	15.0	20.0	10.0	10.0
	of which offshore (electrical)	GW	1.0	21.5	21.5	21.5	37.0	52.0	38.0	38.0
	of which offshore (hydrogen)	GW	0.0	0.6	0.0	2.0	8.0	20.0	0.0	8.0
	Solar PV	GW	6.2	59.3	76.1	42.1	183.1	172.6	126.3	100.0
	of which onshore and offshore	GW	0.7	19.6	24.6	14.3	58.0	58.0	35.0	35.0
	of which buildings and homes	GW	5.5	39.7	51.5	27.8	125.1	114.6	91.3	65.0
	Other renewable	GW	1.0	1.2	0.9	0.8	0.2	0.1	0.2	0.3
	Green gas	TWh	1.7	19.7	9.7	24.4	19.5	13.9	78.5	12.5
	Natural gas extraction	TWh	278	40.6	40.6	40.6	0.0	0.0	0.0	0.0
	Green hydrogen	TWh	0.0	12.5	25.8	18.8	89.8	136.5	43.6	51.2
	Blue hydrogen	TWh	0.0	50.5	49.3	50.1	20.1	33.1	71.0	29.2
	Hydrogen imports	TWh	0.0	22.3	1.8	49.9	50.4	56.2	113.2	252.8
	Hydrogen exports	TWh	0.0	37.1	28.7	57.4	57.1	64.7	112.6	157.8
Flexibility Gas	Methane storage	TWh	unknown	36.4	33.4	37.4	5.5	4.9	11.7	0.5
	Hydrogen storage	TWh	0.0	0.9	3.1	2.0	21.2	13.6	14.3	28.9
Plants	Nuclear	GW	0.5	0.5	0.5	0.5	0.0	3.0	8.0	0.0
	Coal (incl. co-firing)	GW	4.0	0.0	1.6	0.0	0.0	0.0	0.0	0.0
	Gas (natural/green)	GW	20.1	16.3	14.7	14.5	0.0	0.0	0.0	0.0
	Hydrogen	GW	0.0	0.0	1.4	1.9	20.0	15.0	11.0	15.0
Flexibility Electricity	Power-to-gas	GW	0.0	3.0	7.6	3.6	25.0	25.0	16.0	10.0
	Power-to-heat	GW	0.0	3.3	5.1	2.5	10.9	11.1	6.2	3.2
	Batteries incl. EV	GW	0.0	12.3	19.3	8.3	70.3	59.7	38.6	40.6
	Demand response (industry)	GW	0.0	1.7	2.0	1.5	7.7	10.2	3.9	3.1
	Interconnection (E)	GW	5.9	12.8	12.8	12.8	18.8	18.8	28.8	28.8
Totals	Total renewable power	GW	15.2	101.4	119	83.4	266.3	304.7	184.6	174.2
	Total power plants	GW	24.6	16.8	18.2	16.9	20.0	18.0	19.0	15.0
	Total dispatchable power	GW	5.9	33.0	46.7	28.6	132.7	124.8	93.4	85.7
Emissions	Indication of residual emissions	Mt CO_2eq	183	96	91	96	9.0	9.9	8.9	8.8
	Indication of reduction compared to 1990	%	20%	58%	60%	58%	96%	96%	96%	96%

4 IP scenario abbreviations: KA: Climate Ambition, ND: National Driver, IA: International Ambition The 2024 IP scenarios and storylines are part of the development pathway towards the four II3050 scenarios.

5 The table provides the total annual energy demand for each scenario. This annual volume is the sum of the final energy demand from the various sectors and the use of the energy carrier in question for flexibility purposes, including conversion and storage. Final energy demand in the sectors has a certain profile that has to be supplied; the flexible part of demand is energy used for conversion. The Sankey charts provide further details of this.

2.2 Scenario regional breakdown by infrastructure

In order to be able to make any assertions about the future infrastructure, the national scenarios will first have to be translated in terms of their impact on specific locations in the Netherlands, i.e. regionalised. Regionalising the scenarios will add greater depth to them and make them more specific.

Like with the national scenarios, regionalisation requires several choices to be made. These choices have been derived from the scenarios. The choices for the assumed spatial impact of supply and demand are explained in Section 2.2.1. Next, Section 2.2.2 goes into the choices regarding the locations of flexibility resources at the system level, in conjunction with the impact on current infrastructures. Finally, Section 2.2.3 addresses the uncertainties involved in regionalisation.

The process of regionalisation is explained briefly below, whereby the focus is mainly on the link to the infrastructure.

2.2.1 The regionalisation process and the link with the infrastructure

Each scenario parameter that describes supply of or demand for electricity, methane or hydrogen is regionalised at the district level. The scenario report describes the assumptions underlying this regionalisation by sector and category [Reference: https://www.netbeheernederland.nl/dossiers/toekomstscenarios-64].[6] Starting at the district level, a link has been made for each energy carrier to the connections to the specific infrastructure of regional and national network operators to give nationwide coverage.

An example for the electricity infrastructure: a substation serves ten districts.
Electricity demand and supply for each scenario parameter in these ten districts is allocated to this substation.
The main point of departure for the electricity infrastructure is the substations, while the coverage areas served by gas receiving stations are used for methane, and hydrogen transport is based on the shortest distance.
This regionalisation for II3050-2 is unique because it has nationwide coverage and is the same for all network operators. Figure 7 illustrates the regionalisation based on the scenario parameter of onshore wind power.

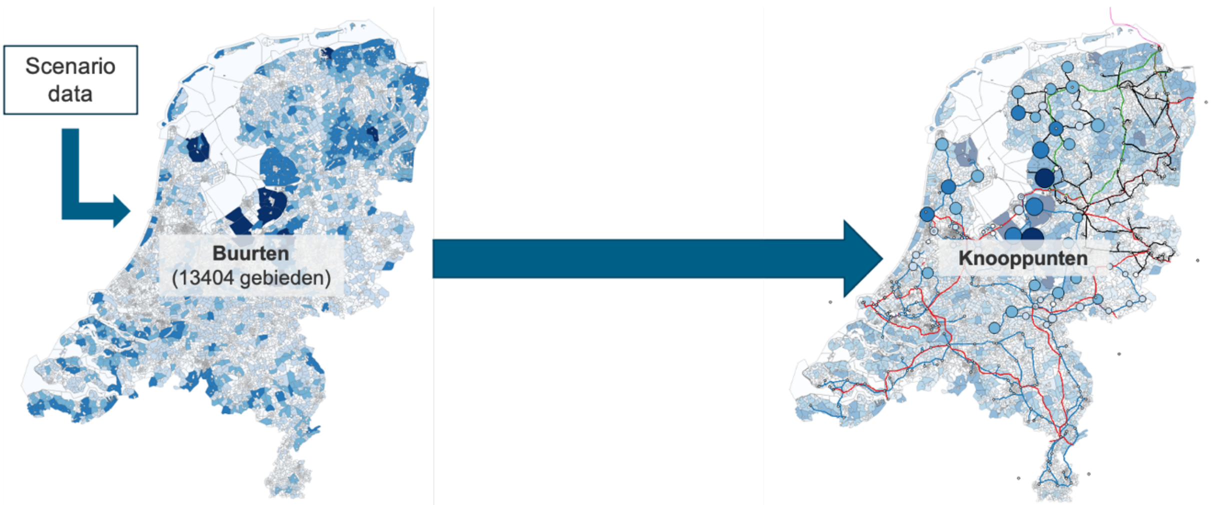

Figure 7: *Regionalisation, example of onshore wind power from districts to hubs*

6 Addition to the scenario report: The regionalisation of green gas production for major sites has been defined based on Gasunie's list of projects, while for smaller sites it is based on energy demand from agriculture.

2.2.1 Regionalisation of flexibility resources

Like in II3050-1, II3050-2 distinguishes between two types of flexibility resources: process flexibility resources and system flexibility resources.

- Process flexibility resources: flexibility resources in a specific process at an end user or connected behind the electricity meter, such as demand side response or hybrid heating in industry. This process flexibility is expected to be in the same districts as where there is demand or a need for energy from these end users.

- System flexibility resources: flexibility resources that fulfil an independent role in the energy system, meaning that where the resource is located is not directly linked to where the end user is located. This is the case with large-scale batteries and electrolysers, for example, which operate on a national level. These flexibility resources can be installed at different places in the country. In II3050-2, the location of these flexibility resources was chosen by looking at the balance between supply and demand for electricity at the substation level. Electrolysers, for example, are installed in areas with extensive surpluses, dispatchable power plants in areas with extensive shortages, and batteries in areas with high demand and supply peaks. This regionalisation is different for each scenario because the regional balance of supply and demand differs per scenario.

2.2.2 Uncertainties in regionalisation and next steps

Top-down regionalisation of the national scenarios adds greater depth to the scenarios. This does mean, however, that more limitations will come to the surface as this top-down approach zooms in more on a local level. Actual local choices depend on far more factors, which are also interrelated. By making these choices nonetheless, the calculations for the networks can be made at the lowest level. The basic assumption is then that the uncertainties in the top-down method will average out at the higher levels. This is why results are not presented at the district level in this study, but rather at higher levels, such as per substation.

The end results are affected not only by changes in the scenario assumptions, but also by the choice for a different regionalisation. One example of this clearly comes to the fore in Chapter 8. How much of the gas grid can be removed depends on the dispersal of central heating boilers and hybrid heat pumps over the Netherlands in 2050. Even with the same number of central heating boilers and hybrid heat pumps, different regionalisations can have a very different impact on the regional gas infrastructure.

2.3 Greater depth on scenarios

The remainder of this chapter will address three key principles and uncertainties of the scenarios. The need for carbon for feedstocks will be looked at in greater detail. Then this chapter will go into the production of synthetic feedstocks and fuels and how variants on the scenarios impact production volumes in the Netherlands.
This chapter will close with an explanation of the impact of a zero-CO_2 electricity system in 2035.

2.3.1 In depth: Carbon needs for feedstocks

The energy transition and feedstock transition are interlinked

The climate transition needs an energy transition, but also a feedstock transition. Carbon is one of the important feedstocks for which a solution is needed. In the current energy system, carbon, chemically bound in hydrocarbons such as coal, oil, and gas, plays a crucial role. On the one hand, carbon is used for energetic applications such as heating, transport, industrial processes, power production, and large-scale energy storage. On the other hand, it is an important building block for a wide range of feedstocks, chemical products, and goods, including plastics, building and insulation materials, and lubricants. This carbon currently mainly comes from fossil energy, a significant proportion of which is used for non-energetic purposes. Sustainable solutions are needed to meet the need for carbon. Instead of fossil carbon from petroleum, for example, renewable carbon will have to be utilised.

For the first time, II3050 looks not only at the energy system in detail, but also at the carbon issue. Carbon needs for production processes in industry have been mapped for each scenario. And an overall carbon balance for the Dutch economy has been established, including import and export flows.

Considerations on the use of renewable carbon in case of scarcity

While ‘fossil carbon’ is available in abundance, ‘renewable carbon’ is scarce, and will be in 2050. Renewable carbon means carbon from renewable sources, from the short carbon cycle. Biomass is one example of such a renewable source. However, there is much less biomass available than would be needed to cover current fossil carbon use for feedstock and energy applications. Recycled (fossil) carbon is renewable when it is not emitted to the atmosphere when burnt; the cycle must be closed. But the available recycled carbon is also nowhere near enough to cover carbon demand either. Finally, carbon can also be captured directly from the air using technological aids in a process called ‘direct air capture’. This process is and is expected to continue to be both energy-intensive and space-intensive, and costly as a result.

In the Netherlands, the scarcity of renewable carbon leads to a kind of distribution issue: what use of renewable carbon would be the wisest choice given the many applications that could benefit from it? Where does the use of renewable carbon create the most value? And is that also the choice society makes?

One thing to bear in mind is that renewable carbon should preferably be used for applications for which no other sustainable alternative is available. This may be to use renewable carbon as a feedstock for industry, but also for specific energetic use in sectors, processes or areas where no alternatives are available (such as part of international transport). The use of renewable carbon would then have to be avoided in applications where alternatives *are* available (such as for heating in homes when a heat grid or electric solution is available).

Specifically as regards green gas, in some parts of industry, carbon from green gas adds value to the process because it is a feedstock. Carbon from green gas does not add value when used for heating in the built environment or industry because the carbon is then simply emitted into the air through chimneys. At the same time, there is still a need for gaseous energy carriers for homes that are hard to make sustainable and for high-temperature processes in industry. The question is, however, what gas that would be. Is the difference in value added indeed a decisive factor in choosing where to supply green gas and where to supply hydrogen?

The availability of carbon will ultimately also affect the choice of solutions in the energy system. The implication is that the policies for a circular economy and circular carbon chains will have to be designed to closely align with climate policy and energy transition policy.

Carbon balance for the National Leadership scenario

The National Leadership scenario is the one with the greatest need for carbon carriers because this scenario has the most extensive synthetic molecule production. What does the carbon balance look like in 2050 according to this scenario?

By 2050, the use of carbonaceous energy carriers will have diminished sharply in the Netherlands. Due to electrification and the use of hydrogen, the energy system will use non-carbonaceous energy carriers on an increasingly large scale. Carbonaceous energy carriers will be replaced by new carbonaceous energy carriers, such as biomass and pyrolysis oil, only to a limited degree. However, there are exceptions: certain industries and international aviation and shipping will continue to need carbon for production processes and carbonaceous synthetic fuels and biofuels respectively, as the most promising renewable alternatives to fossil kerosene, diesel and bunker oil. Carbon will, however, shift from fossil sources to a biogenic source, or it will be recycled from waste or captured from the air using direct air capture.

The amount of carbon needed for products will also decline, partly as a result of the transition to a circular economy. It will, however, drop far less sharply than the use of carbon for energy. In 2050, there will still be a need for plastics, chemicals and (carbonated) foodstuffs. This means that renewable sources of carbon for these products will have to be found in the future, and it means that CO_2 capture and recycling will be needed in places where fossil carbon is still used. For plastics made from petroleum, for example, this means that they will have to be recycled fully after use, or, if that is no longer possible, that the CO_2 will have to be captured during waste incineration and reused as a feedstock. A downside to this is that circular use of materials and substances can only meet carbon demand for production processes to a limited degree and that the circular processes themselves require a lot of energy and space.

The graph below shows the remaining carbon flows in 2050 for the National Leadership scenario. Only those carbon flows that are related to the energy system are shown here. Carbon flows for agriculture, livestock farming, waste disposal, land use and other purposes are not included.

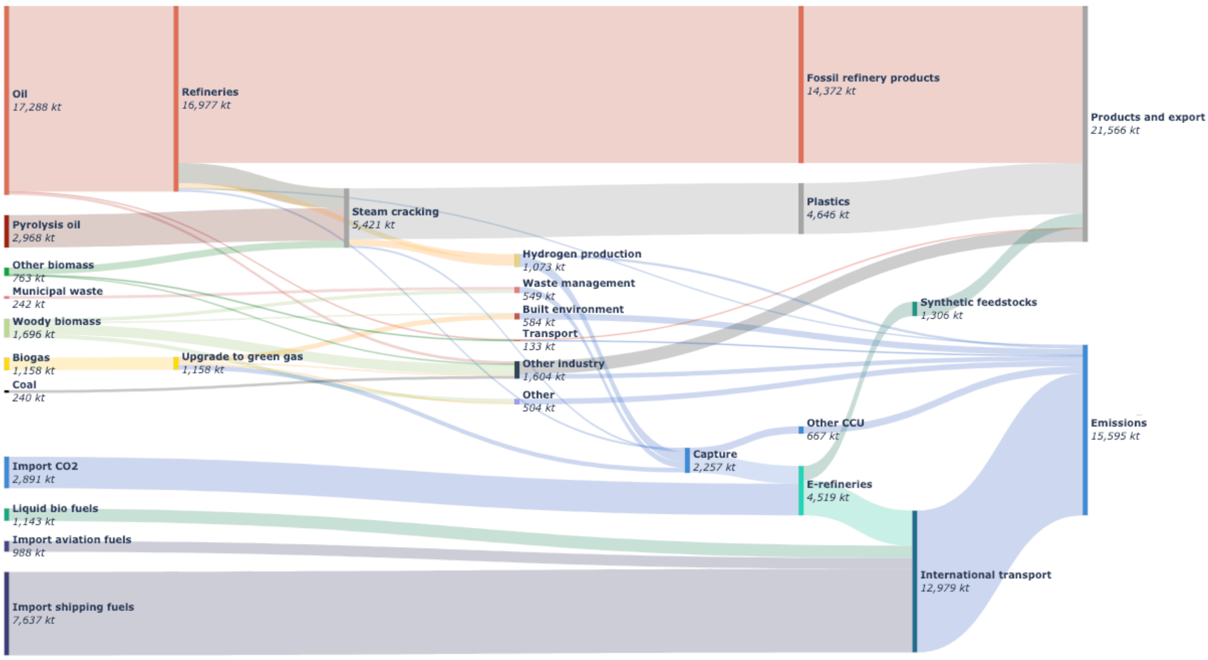

Figure 8: *Carbon flows for the National Leadership scenario in 2050*

Total carbon (C) use is 37 Mt (megatons).[7] Of this amount, 3 Mt is emitted entirely within the borders of the Netherlands and 13 Mt from international transport partly within and partly beyond the borders of the Netherlands. The 3 Mt in emissions comes almost completely from biogenic origins and is spread over all industries. Limited volumes of carbon are, for example, emitted from the use of green gas in the built environment and various forms

7 A separate C atom is about 3.7 times lighter than CO_2. Converting the full 37 Mt of C into CO_2 would, therefore, amount to roughly 140 Mt of CO_2.

of biomass in industry. A total of 4.3 Mt of the 13 Mt in emissions from international transport comes from synthetic fuels (3.2 Mt) and biofuels (1.1 Mt) produced in the Netherlands. The remaining 8.7 Mt comes from imported (sustainable) aviation and shipping fuel.[8]

Carbon is needed for the synthetic fuels produced in the Netherlands. This carbon comes partly from the capture of biogenic CO_2 from industry and waste processing. However, there is not enough renewable CO_2 available in the Netherlands to meet demand from e-refineries in full, which is why it is assumed that 2.9 Mt of renewable carbon will be imported. This carbon can come from the capture of biogenic carbon or from direct air capture in other countries.

Besides the 16 Mt of carbon emitted, 21 Mt is captured in products. 14 Mt of carbon is used by the fossil refinery sector. The scenarios for II3050-2 are based on the assumption that while the fossil refinery sector will shrink by 2050, 30-70% of the current fossil petrol, diesel and other oil product production will continue for exports to outside Europe. This assumption resulted from talks with parties from industry. In addition, 4.5 Mt of carbon will be used for the production of plastic. Two thirds of that will be derived from (recycled) pyrolysis oil, and the other carbon will come from biomass (0.75 Mt) and fossil naphtha from petroleum (1.6 Mt) from the fossil refinery industry. Finally, 3 Mt will still be used for other products, such as chemicals, building materials and synthetic feedstocks.

Dilemma: fossil refinery industry and international transport

Talks with parties from across the industry showed that oil refineries expect that 30-70% of the current production will still be in place in 2050 in the climate-neutral energy scenarios. This will then be production for exports to other parts of the world and/or for international transport, as the European transport system will have largely been decarbonised by then and there will be almost no demand for petrol, diesel and other oil products. The question is how desirable this is and to what extent the Netherlands and industry in the Netherlands can be held responsible for emissions elsewhere (scope 3). There is already debate ongoing about this in society and this will only intensify in the years to come. If global trade flows and global tourism continue, there will continue to be a great need for fuels for international transport. It is still uncertain whether renewable alternatives such as ammonia, biofuels and synthetic fuels will be available in sufficient quantities in time.[9] If the refinery industry continues to be a major industry (30-70% of current volumes), there are two possible situations:

- A situation where the Netherlands exclusively uses renewable fuels for its own international transport needs. These fuels can be made only partially in the Netherlands due to the scarcity of carbon, hydrogen and electricity. This means that there will be a need to import large volumes of renewable fuels that are produced elsewhere. Simultaneously, the fossil refinery industry will export both fossil kerosene and shipping fuel, and the associated emissions, to other countries. This means that while the Netherlands is climate-neutral on paper, it will still contribute to major emissions elsewhere in the world. This situation is depicted in Figure 8.

- A situation where the Netherlands continues to use the fossil kerosene and shipping fuels produced here to the extent that production from sustainable, renewable sources proves to be insufficient. This means that international transport will not be climate-neutral by 2050. The shipping and aviation industries will then still be using fossil fuels in part. This situation is not shown in the figure, but it can be visualised because the incoming flow of ‘aviation and shipping fuel imports’ is linked to the outgoing flow of ‘fossil refinery products’ made from oil.

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8 This is based on the assumption that demand for fuels for international transport in 2050 will be the same as today, and that this demand will be met fully by carbonaceous energy carriers. The Netherlands is currently an important bunkering hub for shipping fuels in particular. Whether this will still be the case in 2050 remains to be seen. Aside from that, some of the demand for bunker fuel may be covered by non-carbonaceous energy carriers such as hydrogen, ammonia and electricity. See footnote in Section 2.3.2.

9 The IEA World Energy Outlook 2022 assumes that 45% of kerosene could be bio-kerosene, and synthetic fuels made using hydrogen could account for around 25% at most. For global shipping, the assumption is that 45% could be powered by ammonia, and that biofuels and hydrogen could cover approximately 20% of demand.

Both situations are problematic and touch on bigger issues, such as the fact that there are not enough sustainable alternatives available for some sectors to cover the volumes they are expected to need for their operations. There is also the ethical and economic issue of how society wants to approach emissions outside the Netherlands that 'originate' in the Netherlands. Both situations mean that the scope 3 emissions will not have reduced to zero by 2050. This contradicts the targets set by a number of major companies in the industry to bring those emissions down to zero.

2.3.2 In depth: synthetic feedstock and fuel production and the system impact

For international transport over very long distances, and then international aviation and shipping in particular, the expectation is that there will still be a great need for fuels with high (volumetric) energy density in 2050; higher energy density than non-carbon alternatives such as electricity and hydrogen can currently offer given the available technology. Part of these fuel needs can be met by biofuels, but biofuels are insufficiently available to cover demand in full. Part of these needs could be met by synthetic fuels made from hydrogen, electricity and carbon at so-called 'e-refineries'. This is an important new purpose for carbon. Section 2.3.1 goes into the need for carbon for feedstocks for industry, and the products derived from it.

Talks with parties from across the industry also showed that, in the storylines of the National Leadership and European Integration scenarios, companies see opportunities for significant production of synthetic feedstocks and fuels in the Netherlands after 2040, for international transport and for the manufacturing of various products in the chemical industry. It is still uncertain how big this market will ultimately be and whether this industry will develop in the Netherlands as well. In the National Leadership scenario, these plans have been included only to a limited degree because they require large quantities of the available hydrogen, electricity and carbon.

The expected production volumes and energy demand from synthetic production are described in the scenario report. The level of production of synthetic products included in the National Leadership and European Integration scenarios equals one third of the total need for synthetic products. This section will go into the system impact and network impact for two alternatives and compare them to the basic version of the scenarios. Both for the National Leadership scenario and for the European Integration scenario, there is an alternative version without any synthetic molecules and a version with a more ambitious goal for the amount of synthetic molecules.[10]

Findings

Of the scenarios in II3050-2, the **basic versions** of the National Leadership and European Integration scenarios show that there can be sufficient electricity and hydrogen available in the Netherlands to be able to integrate the assumed synthetic molecule production levels into the energy system. Carbon, however, will have to be imported.

With higher synthetic fuel production levels, i.e. the **'high' variation** on the scenarios, bottlenecks arise at various places in the energy system. As a result, this version seems a less logical option from the perspective of the energy system, compared to the production levels assumed in the basic version of the scenarios.

For example, extensive additional dispatchable power will have to be created, namely between 4 and 11 GW, including at dispatchable power plants and in hydrogen storage, so as to prevent shortages in the electricity system. On top of that, there will be less electricity 'left over', leading to significantly fewer operating hours for flexible companies, electrolysers and power-to-heat plants, thus making the business case for these technologies less attractive. This seems to result in a large hydrogen import demand, partly on the back of this because domestic production goes down. There will in any event be a major shortage of renewable carbon, meaning that carbon will have to be imported or new technologies such as direct air capture will have to be developed (whereby

[10] See the scenario report for more background information on the data collected from industry and the interpretation and processing of that data.

it should be noted that the scenarios do not take the energy used for that into account). Integrating the additional demand for power and hydrogen leads to major bottlenecks in the electricity and hydrogen infrastructure. This is further explained in chapters 5 and 6.

If this synthetic fuel production industry does not develop in the Netherlands, the **'none' variation** on the scenarios, the findings change. If the Netherlands, in this version, generates just as much renewable energy at sea and on land as is assumed in the basic version of the scenarios, while also building the same amount of electrolysis capacity, there will be electricity and hydrogen surpluses. If no other activity emerges that uses this surplus energy, the Netherlands might become a (major) net exporter of electricity and perhaps hydrogen as well.

Analysis of the system impact of the modelled scenario variations for synthetic fuels

In the variations analysed, supply and demand in other industries have been kept as constant as possible compared to the base scenarios. However, the capacity of flexibility resources has been adjusted in certain respects to ensure the system is balanced in each variation on the scenarios. This mainly concerns the number of hydrogen peak plants needed to meet peak demand for electricity.

The production of synthetic fuels and feedstocks leads to substantial additional demand for electricity, hydrogen and carbon. This additional demand is felt in the energy system. Figure 9 below shows the change in the main system elements for the scenario variations.

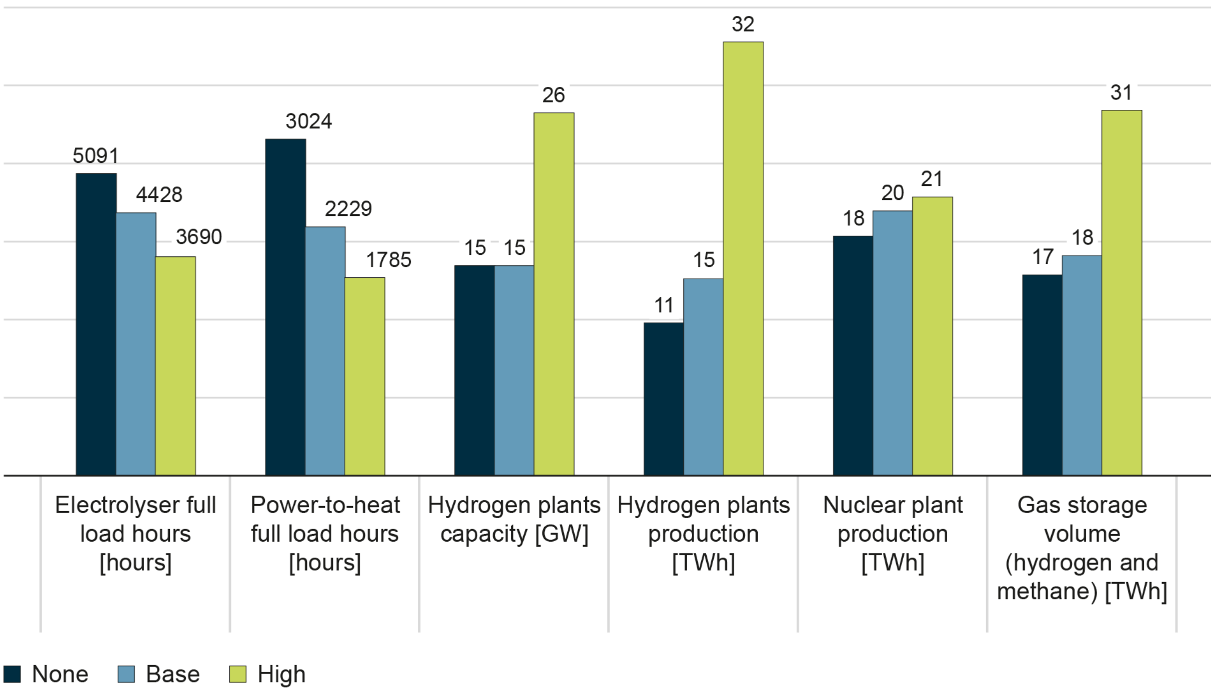

Figure 9: *Utilisation of flexibility resources in the National Leadership scenario*

Flexible users (electrolysers and power-to-heat plants) have considerably fewer operating hours in the version with high synthetic production, compared to the version without synthetic production. Flexible supply from hydrogen plants, on the other hand, has higher production levels. This is caused by the high, largely inflexible electricity demand from e-refineries, which makes surpluses a much rarer occurrence and shortages more common. Hydrogen plants produce three times more electricity in the high scenario than in the scenario without synthetic production and twice the volume produced in the base scenario. This leads to greater storage needs in the hydrogen system: hydrogen has to be kept in reserve to be able to keep power plants up and running. The required storage volume in the high scenario is over 80% greater than in the scenario without production.

The European Integration scenario shows a comparable picture, albeit that the relative differences are smaller than in the National Leadership scenario, because the scale of synthetic production is also smaller in the 'high' scenario for European Integration. Here, too, there is a significant reduction in the number of operating hours for demand flexibility resources, an increase in dispatchable power production to cover shortages, and a rise in the gas storage volume needed to facilitate this.

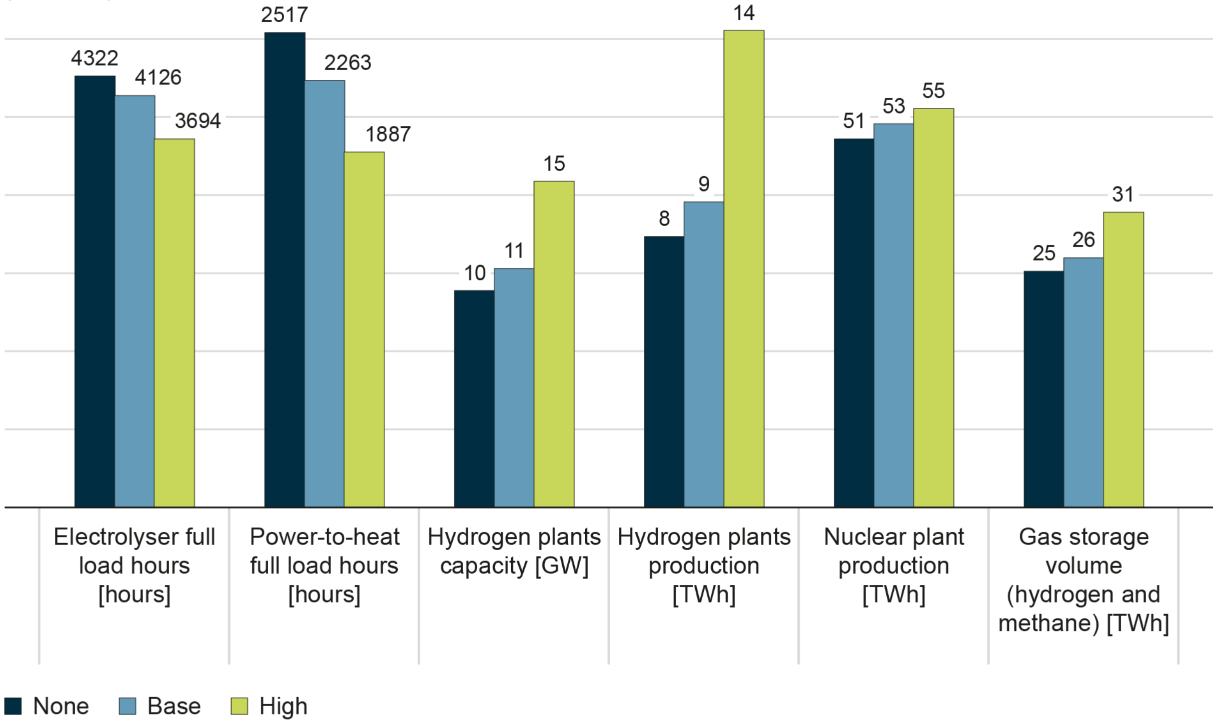

Figure 10: *Utilisation of flexibility resources in the European Integration scenario*

In the National Leadership scenario with high synthetic production, electricity demand is 125 TWh, hydrogen demand 155 TWh and carbon demand 20 Mt CO_2-eq higher than in the version without synthetic production. For the European Integration scenario, the differences are 50 TWh, 65 TWh and 8.5 Mt CO_2-eq respectively.

For the sake of reference: in the basic version of the National Leadership scenario, final use of electricity totals 290 TWh and hydrogen 120 TWh. In the European Integration scenario, final use of electricity totals 255 TWh and hydrogen 90 TWh. In the modelling, the higher demand for electricity and hydrogen in the versions for e-refinery, and the effects that has on flexibility resources' operating hours, has an effect on the net import/export of electricity and hydrogen. The figure below illustrates the differences between the scenarios.

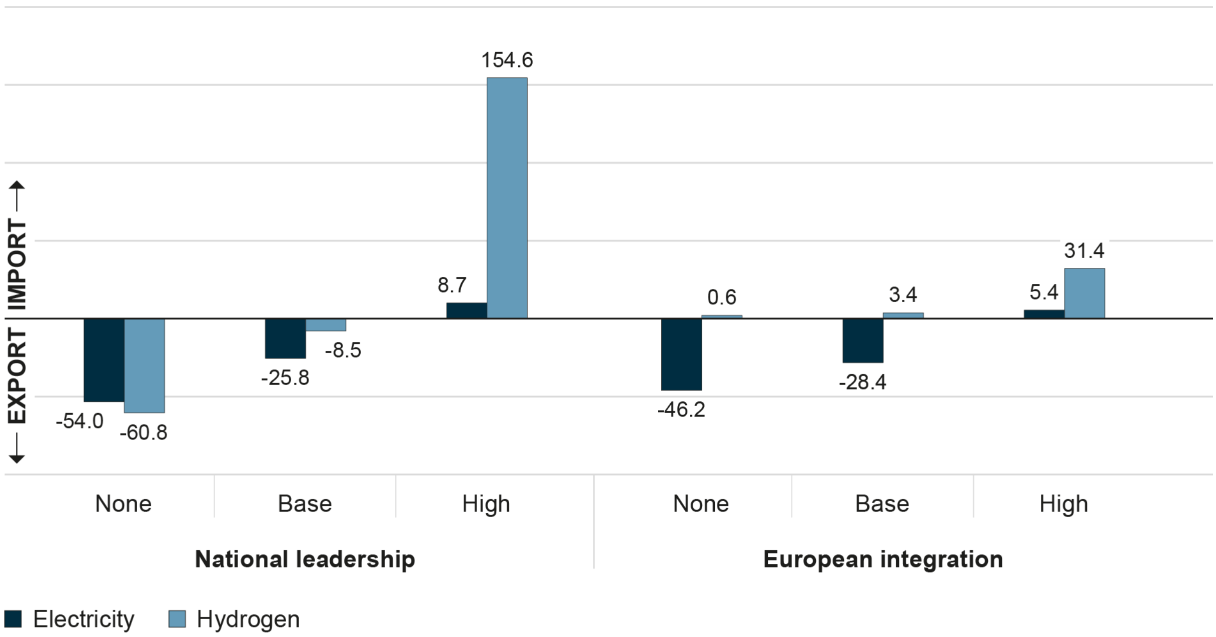

Figure 11: *Effects of the scenario variants on surpluses (negative) and shortages (positive) of electricity and hydrogen*

In the National Leadership scenario without synthetic production, a surplus of both electricity and hydrogen will arise on an annual basis because this scenario overdimensions generation compared to demand. Supply and demand are synchronised in the base scenario. In the 'high' version, on the other hand, we see shortages arise. These shortages are limited for electricity (9 TWh) and much greater for hydrogen (155 TWh). Direct hydrogen demand from the routes with synthetic production is significantly higher in this scenario. At the same time, there is considerably more use of the higher installed capacity of hydrogen plants, which means that fuel is needed for these hydrogen plants, while installed electrolysis capacity is used less, which means less domestic supply of hydrogen.

The European Integration scenario shows the same effects, albeit on a smaller scale, because of the smaller scope of the assumed production of synthetic molecules and because part of the hydrogen needs can be met using blue hydrogen.

Besides this impact on electricity and hydrogen, (renewable) carbon is also a key requirement for the production of synthetic fuels and feedstocks. II3050-2 does not contain an extensive analysis of how the Netherlands can provide this carbon. The options are the following:

- Import it. From Finland, for example, which has a large supply of biomass and, consequently, relatively ample availability of renewable carbon.
- Generation using direct air capture (DAC) technologies. This process is expected to require considerable volumes of heat to release CO_2 from the adsorption medium, as well as electricity for moving air.
- Use from CO_2 emitted from the production of (blue) hydrogen from methane. To close the carbon cycle, this methane must come from a biogenic source (green gas), because the carbon will ultimately be emitted into the atmosphere again when the synthetic fuel is used.

The need for carbon (see Section 2.3.1.) is a key issue in the development of the climate-neutral energy system with climate-neutral feedstocks and material supply chains. Given the many uncertainties that still exist in this respect, it is important that follow-up studies be performed on this topic, focused on technological innovation and making policy more concrete.

2.3.3 In depth: implications of a zero-CO_2 electricity system by 2035

A zero-CO_2 electricity system by 2035
The Spring Memorandum on Climate and the draft National Energy System Plan (NESP) both include the policy intention to accelerate the transition of the electricity system to a completely zero-CO_2 system: '*Zero-CO_2 electricity will in the future be the backbone of the energy system. To achieve climate neutrality by 2050, the electricity system will have to be a zero-CO_2 system as early as by 2035*.'

This policy intention is not included in the scenarios for the 2024 Investment Plans and II3050-2 because these scenarios were developed and adopted prior to publication of the Spring Memorandum on Climate. However, this policy measure is of such importance that a qualitative reflection on the potential impact has been included in this report. Given that the policy intention would primarily have an impact on the developments between today and 2035, this reflection is focused on the Climate Ambition (CA), National Driver (ND) and International Ambition (IA) IP scenarios. In the second edition of II3050, too, these scenarios are used for the period from today to 2035.

Energy production from renewable sources
The scenarios already assume a major increase in energy production from renewable sources over the coming 10-15 years. By 2035, as much as 80-90% of all energy produced will already come from wind and solar sources. The expectation is that, even with a climate-neutral electricity system by 2035, capacities will be within the bandwidth of the ND scenario. However, the ND scenario then ceases to be defined as a 'supporting scenario' and becomes a 'policy reference scenario', i.e. the development direction described in the ND scenario is more likely to be chosen than that of the CA scenario.

Dispatchable power plants
The difference is greater with dispatchable power plants. In the scenarios, these plants will still largely be powered by natural gas in 2035. In a climate-neutral electricity system, alternatives to natural gas will have to be used in these plants. The options are the following:

- CCS at existing (gas-fired) power plants: due to the low number of operating hours and the relatively low CO_2 levels in the combustion gas, CCS at existing gas-fired power plants is unlikely. The use of pre-combustion CCS is a more attractive option, but it requires power plants to be converted to hydrogen, as well as a suitable pipeline network for CO_2 and possibly hydrogen. Another option is to keep coal-fired power plants open, i.e. reverse the decision to close them, and to equip them with CCS facilities. Residual emissions from CCS will then have to be offset by negative emissions. One way of doing this is by co-firing biomass in combination with CCS.

- Low-CO_2 hydrogen: given the scarcity of green hydrogen in 2035 and the intended use in industry, the use of blue hydrogen in particular will be an option. Imported ammonia would also be an option. The benefit of blue hydrogen is that it brings emission reductions that do not directly limit the possibilities in other industries (contrary to the use of green gas or green hydrogen).

- Green gas: green gas can easily be used in existing gas-fired power plants. The use of green gas in the built environment is, however, also important as a way to reduce emissions in the short term and will be stimulated by the government by setting an annual compulsory share of green gas in the total energy mix.

- Biomass: the burning of biomass in combination with CCS is also possible, because it enables major reductions and negative emissions, which will also be necessary in the long term.

- Nuclear plants: building nuclear plants quicker and building more of them (such as SMRs) is also an option, albeit unlikely due to the lead times in the nuclear supply chain.

Impact on electricity prices, energy users, and the business case for flexibility.

With this policy intention, zero-carbon dispatchable production will increasingly determine the market price. This zero-CO_2 dispatchable power comes with considerably higher costs. Cost could double or be even higher. Besides hours when there will be a surplus of electricity, with prices dropping to nil or even going negative, the hours of shortages will be a lot more costly – depending on what technology is used to set the marginal price. If hours with high prices end up being substantially more costly than with the current policy, peak prices could quite conceivably be in line with the peak prices of 2022. Higher peak prices drive up average prices and thus affect all energy users.

Demand flexibility is likely to see its business case improve as many companies that currently still operate 24/7 will not want to assume the higher costs. The development and application of flexibility could, therefore, be higher than assumed in the scenarios, or become more likely – given that the scenarios are already optimistic about the flexibility contribution. The other side of the coin is that companies may not be able to bear these costs, and end up closing down or relocating abroad. Not all energy users have the same scope to be more flexible in their energy demand. The extent of these effects and whether this risk will be offset by mitigating policy is not clear at this point.

Infrastructure

The policy intention also has an impact on the infrastructure. This impact is as follows for electricity, hydrogen and CO_2:

- Electricity: if the zero-CO_2 dispatchable power plants are generally located in the same places as the power plants assumed in the scenarios, the additional impact on TenneT's high-voltage grids will be limited.

- Hydrogen: a lot will change for hydrogen. The cost implications of the design of the national transport network and possible branch pipelines to hydrogen plants will have to be calculated again. In addition, the volumes and required storage capacity in salt caverns will also be much greater in the short term. Over periods with little wind and sunshine, dispatchable power will have to be available for many days on end. It is unclear whether sufficient hydrogen storage capacity can be created in salt caverns. The consequences for the required levels of hydrogen storage and transport will be assessed in a follow-up study to II3050.

- CO_2: the impact on the development of CO_2 infrastructure depends greatly on which of the options and associated locations are chosen. When opting to use existing power plants and equipping them with CCS or developing biomass with CCS, CO_2 infrastructure will be required on site at these power plants. When using blue hydrogen, CO_2 infrastructure at the industrial clusters is the preferred option.

Conclusion

The National Energy System Plan announced that the specifics of a zero-CO_2 electricity system will be worked out further over the coming period. Not until there is more clarity on these specifics will it be possible to actually quantify the impact of the measure.

Recommendations for further developments:

- In order to ensure that a zero-CO_2 electricity system actually reduces total greenhouse gas emissions, it is essential that rights be actually removed from the market. Accelerating efforts in one industry within the ETS will, after all, only mean that emissions are moved elsewhere.

- In the scenarios, the electricity industry is already largely zero-CO_2 by 2035. Does it make sense for the transition as a whole to put additional effort into lowering emissions in the electricity industry by a few more percentage points when you can achieve comparable reductions elsewhere with less effort?

- Pay attention to the effect that this intervention has on market prices, and with that on the affordability of electricity and the attractiveness of electrification, the impact on end users, and the security of supply.

- After all, security of supply becomes a bigger challenge with a large share of weather-dependent electricity in the electricity mix. In the current development pathway, the availability of sufficient dispatchable power is, therefore, by no means a given. It is important to take this situation properly into account in each intervention in the remaining dispatchable power.

Chapter 3

Analyses of the energy system and flexibility

3.1 Conclusions and recommendations

A large and diverse portfolio of flexibility resources is needed to match supply and demand in a climate-neutral energy system.

- In order to match supply and demand over both short and longer periods of time, there is a major need for flexibility resources in each of the scenarios. Flexibility is needed both for each energy carrier separately and between all the energy carriers analysed: electricity, hydrogen, methane and heat.

- The projected flexibility need requires a mix of existing and new technologies. This is required on the one hand for the short to medium term (e.g. supply and demand response, battery storage, and heat buffers), and on the other hand for the long term (e.g. in the form of combined power-to-gas, gas storage and gas-to-power). Various forms of flexibility will be required and will complement each other.

- By 2050, demand in the electricity system will exceed the amount of power generated from renewable sources at peak times by 35-50 GW, which is 2-3 times higher than today. These shortages will have to be covered by flexible resources. The scenarios assume that 25-50% of industrial demand may adapt flexibly to the amount of renewable energy available. The capacity for international interconnections will be 2.5-3.5 times greater than it is today. In addition, 15-20 GW of power produced by dispatchable power plants - comparable to today's power plant fleet - and 40-70 GW from batteries may be needed in a year with a normal weather profile to prevent shortages. Furthermore, there will regularly be surpluses, which at peak times can be up to 65-95 GW. These surpluses are not only used to charge batteries and for exports, but also utilised through flexible electrolysis (10-25 GW) and power-to-heat units (3-11 GW). Production will sometimes also be (maximum of 35–50 GW).

- In the hydrogen and methane systems, storage plays a key role in flexibly balancing supply and demand. In a year with an average weather profile, the required gas storage capacity is between 20 and 30 TWh. Hydrogen storage provides flexibility to the electricity system by integrating variable hydrogen production from electrolysis and keeping sufficient volumes of hydrogen in storage to operate dispatchable power plants at peak times. Methane, and in some scenarios hydrogen as well, plays a flexible role in the heat supply as hybrid heat pumps switch from electricity to gas on cold days.

- Collective heating systems require large-scale heat storage and back-up facilities to bridge cold spells. Back-up facilities can take the form of electric boilers or methane or hydrogen boilers, making these energy carriers a key flexibility provider for the heat supply.

While some of the flexibility resources will be needed for only a limited number of hours per year (dozens to hundreds), they are still crucial in balancing the energy system. With the way the market is currently organised, it is not a given that these flexibility resources will be profitable and that the market will make the necessary investments in sufficient back-up capacity.

- There are great uncertainties and fluctuations in the utilisation of the various flexibility resources. The expected number of operating hours of a flexibility resource can differ greatly depending on the development of other flexibility resources, on weather conditions and on developments in other countries. These uncertainties lead to major investment risks.

- Given these fluctuations, the question arises of how much security and robustness has to be built into a future sustainable energy system, and what kind of costs would be acceptable in doing so. Building back-up capacity and energy storage facilities makes the energy system less sensitive to fluctuations and can bring greater stability and security of supply. This is particularly important for socially relevant processes such as the heat supply in the built environment.

- During adverse conditions, cold spells, periods with little wind and sun, and unexpected asset outages, more flexibility assets will be required than assumed in the base scenarios. The variation is particularly large for certain 'last resort' flexibility resources of the energy system. Under the most unfavourable conditions that have been analysed, 2.5 to 3 times more hydrogen and methane storage capacity might be needed than in the base scenarios. For dispatchable power plant capacity, this is 1.4 times more, and for the need for back-up and buffering for heat grids, it is 4 times more.11 These assets are needed during cold spells and 'Dunkelflaute' situations, i.e. prolonged periods with little solar and wind power generation. In order to maintain sufficient levels of supply in the electricity system, the scenarios require a lot of flexibility, provided partly by hydrogen storage, to be able to operate dispatchable power plants.

- A dilemma is that irregular or unexpected situations can quickly lead to a need for major (peak) capacities in the range of 5-15 GW to balance supply and demand, but these situations occur only for a limited number of hours. As a result, only a small part of the demand volume cannot be covered in these cases (around 0.1-0.2% of annual demand and a few tens of hours per year). This means major investments that are difficult to recoup in a normal market.

- What also should be considered in this respect is to what extent these additional investments outweigh alternatives such as accepting that certain users, both on the demand and the supply side, will reduce their production or consumption in certain situations – either voluntarily stimulated by market incentives or by being shut down.

There is still great uncertainty as to what the optimum portfolio of flexibility resources in the future energy system will look like and how best to distribute these resources geographically across the country. This is a complex issue that requires further attention.

- The energy system and the flexibility mechanisms are a complex system with numerous interdependencies within and between energy carriers. Choices for one aspect of the energy system can have major consequences for other aspects, meaning that system choices and flexibility resources cannot be viewed in isolation.

- The use of flexibility resources such as conversions, hybrid applications, peak and back-up facilities, and storage will increasingly lead to collaboration and links between different energy carriers. Flexibility is a key driver for this energy system integration.

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[11] This is based on the assumption that there must not be any hours when not enough electricity is produced to meet demand. When assuming a higher acceptable limit of, for example, 6 hours, the required dispatchable power can turn out considerably lower.

- If the available capacity of a particular flexibility resource is greater or less than what is assumed in the base scenarios or even lacking altogether, this results in numerous changes to the energy system. The implications of a number of variations on the National Leadership scenario have been analysed in this study. In variants with less industrial demand response, up to 10 GW of additional dispatchable power is needed, albeit with limited operating hours (< 300 hours). Greater interconnection capacity can bring down electricity prices, but also reduce operating hours for domestic electrolysis and power-to-heat due to increasing competition for domestic production. The variants with less battery storage capacity come with higher electricity prices and more extensive use of alternative supply flexibility, such as hydrogen plants, industry demand response, and imports. Only a limited number of variants have been assessed. To gain a better understanding of the interplay between flexibility resources, further research is required.

- Besides the impact on the energy system, other key considerations in determining the required flexibility resources and infrastructure are the choices on where to develop flexibility and what (local) behaviour incentives to use. Choosing those locations smartly and including local incentives (during a limited number of hours per year) to balance supply and demand will enable a smarter use of assets and help to tackle network congestion.

3.2 Introduction

A reliable and safe energy system requires a balance between supply and demand at all times. This requires not only transport networks, but also various forms of flexibility. Flexibility is provided by resources in the energy system that can be steered to respond to imbalance in the supply of and demand for an energy carrier. Flexibility can be provided by energy storage, conversion between different energy carriers, transferring energy to and from other countries, and the controlled adjustment of energy production and demand.

In the future energy system, energy supply is largely made up of weather-dependent wind and solar power generation. In what form and at what times energy is needed will also change. The combination of the developments in supply and demand will lead to new challenges in keeping the energy system balanced at all times.

This study includes a quantitative assessment of how the need for flexibility will develop in the Dutch energy system over the period to 2050, taking the base scenarios and their variants as starting points. It looks at how to provide this flexibility through a combination of various flexible assets and what factors play a key role in making this happen.

This chapter will focus on the flexibility topics and analyses that are new compared to the first edition of II3050. It provides an overview of the required flexibility capacities and calculated operating hours in the updated base scenarios (3.3), in-depth analyses of the influence of weather conditions and alternative flexibility portfolios (3.4), and a consideration of the effect of flexibility on a regional level (3.5). Background information about the calculation method used, the available flexibility technologies and the (hourly) use of flexibility resources is provided in Appendix D.

3.3 Flexibility analysis results

II3050-2 uses a new calculation method for the deployment of flexibility resources compared to the first edition. Where the first edition determined the use of flexibility resources by looking at surpluses and shortages on an hour-by-hour basis, the second edition uses a method in line with the current European market model where (hourly) prices determine which flexibility resources are used and when. See Appendix D.1 for a detailed explanation of the new calculation method.

Even though a new calculation method was used and the scenarios have been revised, II3050-2 still predicts, like the first edition, that a large and diverse portfolio of flexibility resources will be needed to balance supply and demand. This is mainly because the underlying driver of the need for flexibility has remained unchanged: the energy transition will increase the imbalance between supply and demand due to the significant growth in weather-dependent wind and solar power generation, which does not always match the demand for energy.

The table below shows the installed capacities and the number of operating hours per flexibility resource for all energy carriers and the base scenarios in II3050-2. The installed capacities were used as input for the model, and the hours of operation were calculated using the Energy Transition Model. In doing so, various preconditions were considered.

- The starting point is the non-controllable production and demand in the scenarios, which determine the balance or imbalance for each energy carrier.
- Supply of and demand for all energy carriers must be fully balanced at all times throughout the year modelled.
- The flexibility volumes are based on what is needed to balance the energy system in a year with an average weather profile and under normal conditions. In order to balance the energy system both in case of more challenging weather conditions or unforeseen events, additional capacity is needed. This will be explored further in Section 3.4.
- The utilisation of each flexibility technology needs to be plausible and stay within a realistic bandwidth. This was assessed by looking at economic indicators, such as the number of operating hours per year.
- The storylines of the various scenarios determine the required degree of self-sufficiency versus imports from other countries.

Due to the broad scope of the energy system, the associated complexity and the fact that II3050 is intended to be an exploratory long-term study, the analysis did **not** take the form of an **optimisation** but was simply a **simulation**. This means that the flexibility volumes in the base scenarios (see Table 6) can be considered **one possible way to meet** the expected flexibility need. This is why II3050-2 focuses extensively on the uncertainty with respect to flexibility and the impact of various conceivable developments, both on the quantities and the technical and economic characteristics.

			2019	2030				2040				2050
Category	**Technology**		**Ref**	**KA**	**DEC**	**NAT**	**EUR**	**INT**	**DEC**	**NAT**	**EUR**	**INT**
Power plants	**Nuclear**	**GW**	0.5	0.5	0	1.5	4.0	0	0	3.0	8.0	0
		full load hour	7630	4860	0	6264	6172	0	0	6606	6597	0
	Coal	**GW**	4	0	0	0	0	0	0	0	0	0
		full load hour	4465	0	0	0	0	0	0	0	0	0
	Methane	**GW**	20	16	7	6	6	4	0	0	0	0
		full load hour	3662	1779	1134	1200	1072	1471	0	0	0	0
	Hydrogen	**GW**	0	0	11	9	9	11	20	15	11	15
		full load hour	0	0	1109	1056	1102	1205	874	978	835	922
	E-boilers	**TWh**	0	0	1	1	0	0	4	4	0	0

Back-up heat grid	**Gas boilers**	**TWh**	1	0	1	3	3	2	1	3	4	6
Supply response	**Curtailment**[12]	**GW**	0	31	43	49	41	34	47	40	36	48
		TWh	0	15	8	11	9	9	5	9	7	13
Flexible demand for electricity	**DSR in industry**	**GW**	0	2	5	5	3	3	8	10	4	3
		full load hour	0	84	559	558	627	707	301	451	605	627
	Power-to-gas	**GW**	0	3	15	17	9	8	25	25	16	10
		full load hour	0	5513	3964	4346	4117	3801	3909	4428	4126	3916
	Power-to-heat	**GW**	0	3	10	10	5	4	11	11	6	3
		full load hour	0	1819	1145	1295	911	712	954	1550	1265	888
Storage	**Battery storage**	**GW**	0	12.3	42.4	42.0	29.2	24.7	70.3	59.7	38.6	40.6
		TWh storage volume	0	0.1	0.4	0.5	0.3	0.3	0.7	0.7	0.5	0.5
		Charging cycles	0	103	94	92	90	86	93	96	86	85
	Hydrogen storage	**TWh storage volume**	0	1	11	9	10	15	21	14	14	29
	Methane storage	**TWh storage volume**	0	36	13	14	20	15	6	5	12	1
	Heat storage	**TWh storage volume**	0	8	11	11	5	4	14	12	7	3
Import/export	**Electricity**	**GW**	7.8	12.8	14.8	14.8	14.8	14.8	18.8	18.8	28.8	28.8
		TWh net import	3	-10	-13	-30	-23	-12	-7	-26	-28	-22
	Hydrogen	**GW**	0	10	15	15	15	15	20	20	25	25
		TWh net import	0	-15	8	-31	27	69	-7	-8	1	95
	Methane	**GW**	106	105	100	100	100	100	95	95	90	90
		TWh net import	99	182	46	45	53	48	-1	2	43	0

Table 6: *Overview of flexibility quantities and usage in the base scenarios*

All of the scenarios project a need for a large and diverse portfolio of flexibility resources in 2050 to balance supply and demand for all energy carriers. Growth of the flexibility resource portfolio is driven mainly by technologies that have yet to be scaled up.

By 2050, demand in the electricity system will exceed the amount of power generated from renewable sources at peak times by 35-50 GW, which is 2-3 times higher than today. These shortages will have to be covered flexibly. The scenarios assume that 25-50% of industrial demand may adapt flexibly to the amount of renewable energy available. The capacity for international interconnections may be 2.5-3.5 times greater than it is today. In addition, 15-20 GW of power produced by dispatchable power plants - comparable to today's power plant fleet - and 40-70 GW from batteries may be needed in a year with a normal weather profile to prevent shortages. There will also regularly be surpluses, which at peak times can be up to 65-95 GW. These surpluses are not only used to charge batteries and for exports, but also utilised through flexible electrolysis (10-25 GW) and power-to-heat units (3-11 GW). Production will sometimes also be reduced (maximum of 35–50 GW). Not all these flexibility resources will be available at all times and some of the capacity can be used both for surpluses and for shortages, such as batteries and interconnection capacity. In 2030, flexibility resource capacity is expected to still be relatively limited

[12] Contrary to other flexibility resources, curtailment does not require a physical asset, as it constitutes an operational intervention in energy production from renewable sources. The figures shown do not include so-called 'overplanting' of solar power (structural limitation of peak production).

and most of the technologies used will be the ones that have already reached an advanced state of development today. Methane plants and battery storage will be the main resources used to cover shortages, while surpluses will primarily be dealt with by exporting energy or temporarily reducing production, with a growing role for conversion into hydrogen and heat. By 2040, the full range of the flexibility resource portfolio will already be needed, but with lower capacities than in 2050, because power generation from renewable sources and electrification will not have reached full maturity by 2040.

In 2030, hydrogen will still show limited development in terms of flexibility. However, first steps are taken for using electrolysis (3 GW) and storage (1 TWh). In the years to 2040, there will be a significant growth in the need for storage, the supply of power-to-gas and the capacity of dispatchable hydrogen-powered power plants. After 2030, hydrogen will play an increasing role in balancing the electricity system. Hydrogen storage provides flexibility to the electricity system by integrating variable hydrogen production from electrolysis and keeping sufficient volumes of hydrogen from storage available to operate dispatchable power plants at peak times.

The role of methane will diminish rapidly after 2030. By 2040, methane will still play a role in balancing the electricity system through methane plants, while by 2050 the methane system will primarily provide flexibility in meeting demand for heat at peak times, both for heat grids and for individual homes through hybrid heat pumps.

Collective heating systems require buffering and back-up facilities to bridge cold spells. In addition to (large-scale) heat buffers, these back-up facilities can, come in the form of electric boilers or methane or hydrogen boilers, making the underlying energy carriers a key source of flexibility for the heat supply.

Figure 12 illustrates the role of flexibility in the electricity system in 2050 in the National Leadership scenario. The graph shows a residual load duration curve. For every hour of the year, an analysis was performed to determine the extent to which power generation from wind and solar would be able to meet basic demand. The hours were subsequently sorted from hours with the greatest shortages to hours with the greatest surpluses (black line). The coloured areas show how these shortages and surpluses are covered by deploying flexibility resources.

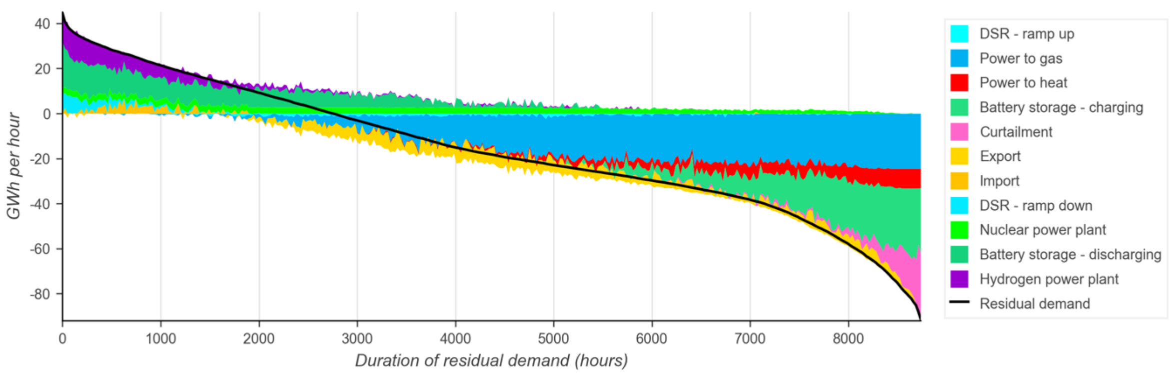

Figure 12: *Residual demand and deployment of flexibility in the electricity system.*

By 2050, there will be shortages for just under 3,000 hours per year: base electricity demand during those hours will be greater than the available wind and solar production. Shortages will be alleviated using power generated by hydrogen plants, power from batteries, demand side response (DSR) in industry, power imported from other countries, and nuclear power. During roughly 6,000 hours, however, there will be surpluses, i.e. more power generation than demand. Flexibility resources will ensure that every hour of the year is balanced. Surpluses are converted into hydrogen using power-to-gas and/or into heat using power-to-heat technologies, used to charge batteries, or exported to other countries, while production will temporarily be curtailed when surpluses mount.

During some hours, especially in the middle section of Figure 12, flexibility resources are deployed both to meet additional demand and to feed additional power into the grid. As a result, the flexibility resources do not cover the area between the horizontal axis and the residual demand line exactly, but they stick out both above and below this area. This is because flexibility resources do not only respond to domestic surpluses and shortages, but rather to price incentives. During some hours, for example, it can be economically beneficial to import cheap power from abroad to charge batteries, or to discharge batteries to operate local electrolysers and power-to-heat plants for more operating hours. A detailed description of the (hourly) imbalance and deployment of flexibility resources for all energy carriers, scenarios and years is provided in Appendix D.2 and D.3.

3.4 Flexibility portfolio robustness and variation

In the base scenarios and as already mentioned in the previous section, the chosen portfolio of flexibility resources results from a simulation and not an optimisation. There is still a lot of uncertainty around the development of various flexibility technologies - in terms of technological aspects, costs, acceptance, availability of materials, etc. - and their role in the energy system of the future. Based on what we know now, there are countless possible combinations of flexibility technologies that can lead to a balanced system. Also, the flexibility volumes in the base scenarios were calculated based on a single year with an average weather profile.[13] With more exceptional weather conditions, unforeseen events or adverse developments, the capacities in the base scenarios would not always be enough to keep the energy system balanced at all times. This section will explore how robust the energy system is and how the deployment, i.e. operating hours, of the flexibility resource portfolio changes when the circumstances are different from what is assumed in the base scenarios.

3.4.1 Weather conditions

In the future, the energy system will increasingly be driven by weather conditions. With solar and wind as the main sources of energy, the energy supply varies from hour to hour and there are ‘good’ and ‘bad’ energy years: years with high production from renewables or years with low production from renewables due to extensive or little sunshine and wind respectively, and with varying levels of alignment with demand. Appendix D.4 provides a detailed analysis that calculates the implications of the scenarios from II3050-2 based on the different weather conditions over the past 30 years (1990-2019). The main results will be described in this section, with a specific focus on the National Leadership scenario (2050).

For the primary renewable sources, i.e. solar and wind, the variation in production between good and bad years is a maximum of 15% and 25% respectively. Solar and wind power are not only the most important primary energy sources for the electricity system, they are also an important source for the hydrogen supply through electrolysis, and for the heat supply through power-to-heat technologies. Other energy carriers can be used when shortages arise in the electricity system due to a lack of solar and wind power, such as through dispatchable hydrogen-powered power plants or hybrid heat pumps that switch to methane when electricity is scarce. One consequence is that the volatility of energy production from solar and wind will reverberate across the whole energy system.

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13 The base scenarios of II3050 use weather profiles from 2012, with two adjustments: The temperature has been raised to take the average to 11.8 degrees, which is the expected average temperature in 2050. In addition, the full load hours for onshore wind power and offshore wind power have been increased based on feedback from stakeholders, to 3,200 and 4,750 hours respectively, to factor in expected technological developments. The idea behind this is to create a year with an ‘average’ weather profile in the base scenarios.

The analysis below shows two things. On the one hand, variations in weather conditions mean that flexible system elements such as electrolysers, power-to-heat plants, and imports/exports are used much more in one year than in another (by tens of percentage points). This means that the proprietors of flexibility resources have to operate in a market with a lot of uncertainty and volatility. Whether the current market mechanisms are adequate and whether there will be sufficient possibilities to mitigate risks was not analysed in this study, but certainly requires further attention.

On the other hand, it turns out that a larger number of assets than assumed in the base scenarios will be required for a number of 'last resort' flexibility assets in the energy system. These assets help keep the energy system balanced under varying weather conditions. In the most unfavourable scenario variants that have been analysed, 2.5 to 3 times more hydrogen and methane storage capacity will be needed than in the base scenarios. For dispatchable power plant capacity, this is 1.7 times more, and for the need for back-up and buffering for heat grids, it is 4 times more. On top of that, substantial (peak) capacities and storage volumes will quickly be needed in unusual or unexpected situations to prevent shortages, while these back-up facilities have a limited utilisation rate. There will be many years during which they will not be necessary and even during bad years they will often be utilised for only a few dozen hours. Building these facilities will require large investments that, in a normal market, are unlikely to be recouped, but these facilities do help make the energy system reliable and, therefore, have a value for society.

3.4.1.1 Dispatchable power plants

The operating hours of dispatchable power plants depend greatly on the availability of solar and wind power. When the wind does not blow sufficiently or the sun does not shine, power plants can be used to prevent shortages. Since one year is sunnier or windier than the next, the operating hours of power plants will also vary significantly from year to year. Looking at historic weather conditions over the 1990-2019 period, the operating hours roughly double in years with the most use of power plants compared to years when they are used the least. In years with extensive deployment of power plants, the number of full load hours amply exceeds 1,000, with the International Trade scenario showing the highest value (1,544 full load hours in the year with the 2010 weather profile). In years with little use of power plants, the figure is well below 1,000, with the Decentral Initiatives scenario showing the lowest value (564 full load hours in the year with the 2000 weather profile).
The graph below shows the variation in operating hours for the National Leadership scenario in 2050.

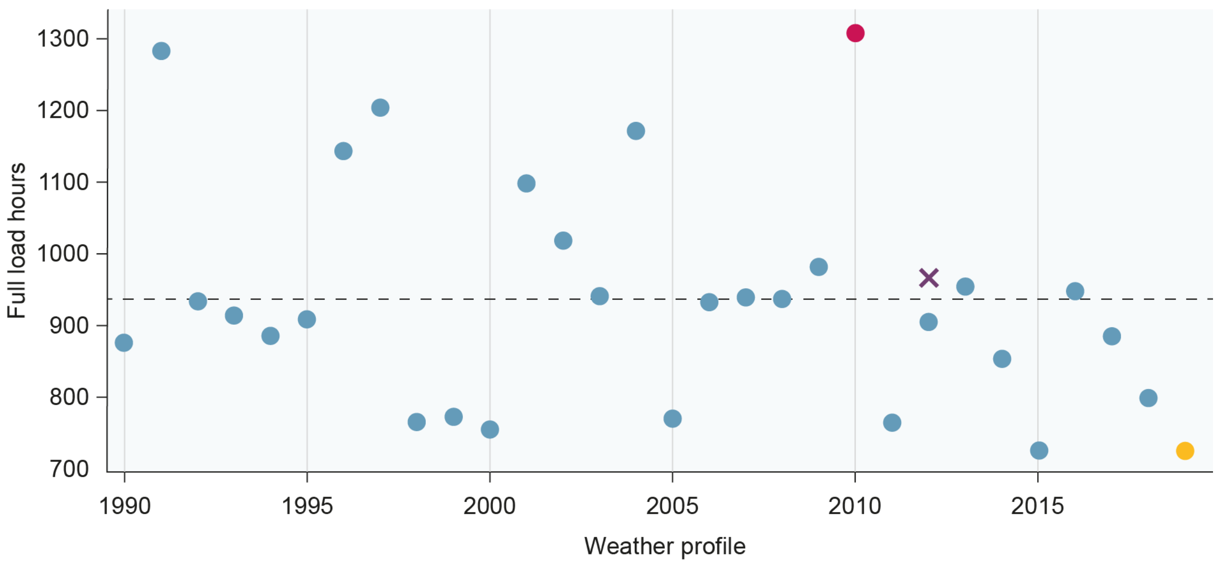

Figure 13: *Number of full load hours of hydrogen plants for the weather profiles from the 1990-2019 period according to the National Leadership scenario in 2050. The yellow dot marks the year with the lowest number of hours, the red dot marks the year with the highest number, and the purple cross indicates the base scenario. The grey dotted line shows the 30-year average.*

The above figures are based on the assumption that the installed capacity of power plants in any year with any weather profile is the same as the assumptions from the base scenarios. The available flexibility resources, which besides power plants also includes storage in batteries, interconnections and demand side response, are not able to prevent shortages in all weather profiles. In the National Leadership scenario, a shortage arises in 10 of the 30 years for which these calculations were made. This means that during those years with their respective weather profiles, there are hours when demand for electricity exceeds supply, meaning that electricity cannot be supplied to some consumers.

In most of the years, these shortages are limited to a few hours or amount only to a reduction in voltage. In three of the years, the shortages are greater, running up to 7.3 GW and totalling 46 hours with shortages. The year with the biggest shortage (2010) was one with a period of 'Dunkelflautes', i.e. several consecutive dark days in winter without wind. Partly given the fact that, in 2050, a large part of the built environment will depend on electricity for heating, this combination of high demand and low generation will result in several dozen hours of shortages. These add up to a volume of 150 GWh. In terms of demand over a whole year, this is a modest amount, representing around 0.05% of final use. In order to prevent shortages in all of the 30 weather profiles, the National Leadership scenario would require 7.3 GW of additional dispatchable power.[14] This comes on top of the 18 GW maximum produced by power plants that are already assumed in the base scenario.

These additional power plants will not be used in most years, which is a key point to consider. And even during the years that they are needed, they will only run for several dozen hours in a year. Investments in the stability and robustness of the energy system are costly and cannot always be recouped in the market.
This again brings up the question of how much security and robustness should be built into a future sustainable energy system, and what costs would be acceptable in doing so.

3.4.1.2 Flexible demand for electricity

Fluctuating production of electricity from renewable sources is cushioned not only by dispatchable power plants, but also by adaptiveness on the demand side. Electrolysers and power-to-heat plants are used more in years with ample production than in years with little production of electricity from renewable sources. The opposite applies in industrial demand response: industry is more likely to reduce or interrupt demand in years with little supply of renewable power, i.e. in years of scarcity.

The graphs below show the variation in the use of electrolysers and industrial demand response between years with different weather profiles for the National Leadership scenario in 2050.

[14] This is based on the assumption that there must not be any hours when not enough electricity is produced to meet demand. When assuming a higher acceptable limit of, for example, 6 hours, the required dispatchable power can turn out considerably lower.

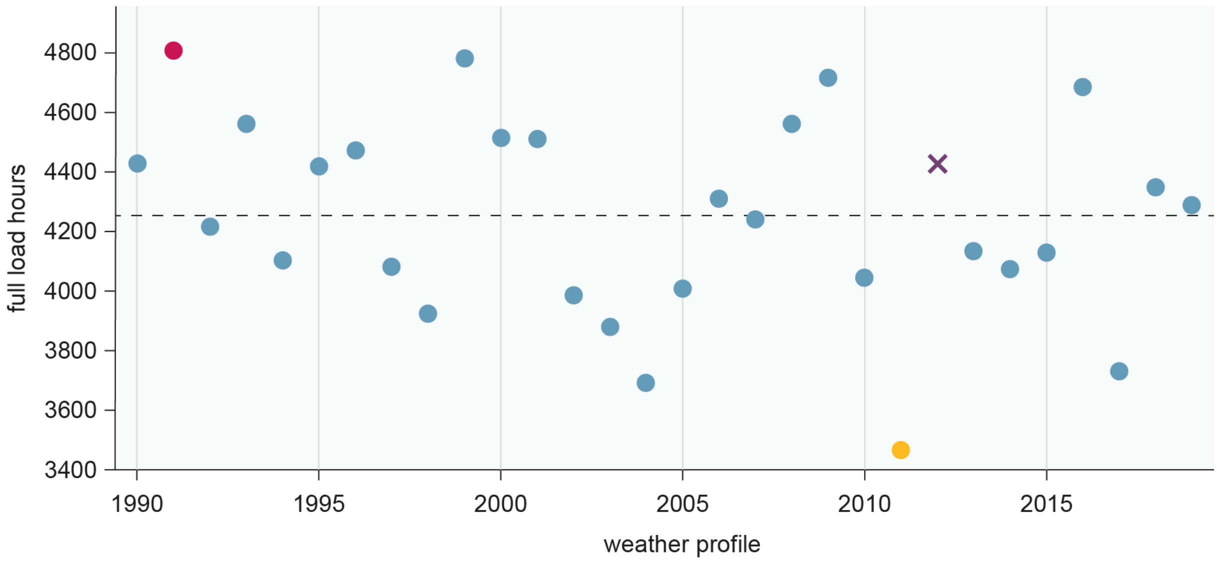

Figure 14: *Number of full load hours of electrolysers for the weather profiles over the 1990-2019 period in the National Leadership scenario in 2050. The yellow dot marks the year with the lowest number of hours, the red dot marks the year with the highest number, and the purple cross indicates the base scenario. The grey dotted line shows the 30-year average.*

Figure 15: *Number of full load hours of industrial demand response for the weather profiles over the 1990-2019 period according to the National Leadership scenario in 2050. The yellow dot marks the year with the lowest number of hours, the red dot marks the year with the highest number, and the purple cross indicates the base scenario. The grey dotted line shows the 30-year average.*

Both electrolysis and demand side response in industry show big differences in operating hours between the various weather profiles. Electrolysis operates for 40% more hours in the highest year than it does in the lowest year. For industrial demand response, the variation is as much as 180%. The other three scenarios show a similar picture, despite the differences in the composition of the production mix and the portfolio of flexibility resources. For example, the difference in full load hours for electrolysis between the lowest year and the highest year is 40%

in the National Leadership scenario, 47% in the Decentral Initiatives scenario, 51% in the European Integration scenario, and 65% in the International Trade scenario.

Electrolysis kicks in during hours when the price of electricity drops below a certain threshold. These can be hours with extensive solar and wind power production, hours with low demand, hours with extensive cheap import options, or a combination of these circumstances. It is not just about averages over a whole year, but also about the balance between supply and demand from hour to hour during the year. The weather profile from 1991 is an interesting example in this context. This is a year when wind and solar power generation is below the multi-year average. Electricity production by hydrogen plants is at the highest level of all the weather profile years and demand response in industry is well above the average. On top of that, hydrogen production from electrolysis is at the highest level of all the weather profile years and power-to-heat production is above average. All of this was caused by a relatively substantial mismatch between production and demand. There is little production during periods of high demand, meaning that extensive balancing is needed through hydrogen plants and demand reduction. And there is extensive production during periods of low demand, creating ample opportunity for electrolysers (and other forms of flexible demand such as power-to-heat technologies) to convert cheap power into hydrogen and heat.

3.4.1.3 Energy storage

Weather conditions also have an effect on the energy system's storage needs. Energy reserves are needed to a greater extent to bridge shortages in years with low production from renewables than during 'good' years. There is a major difference between energy carriers here: where batteries are used relatively constantly over the years, hydrogen use and methane use show major differences between 'good' and 'bad' years.

Figure 16 shows the number of charging cycles of batteries for the weather profiles over the 1990-2019 period in the National Leadership scenario 2050.

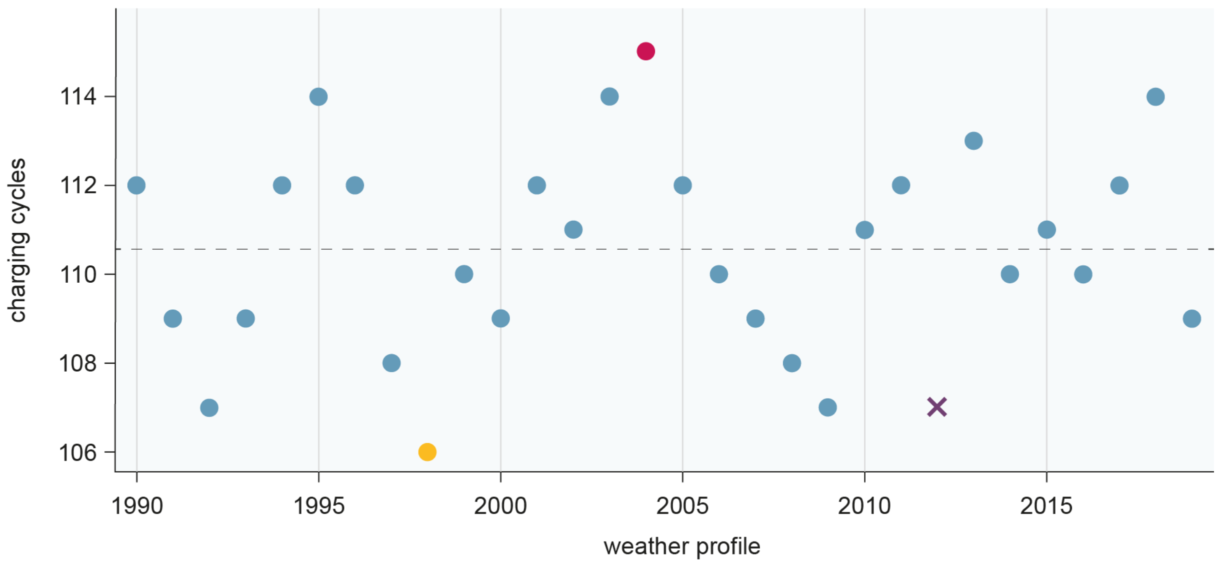

Figure 16: *Number of battery charging cycles for the weather profiles over the 1990-2019 period in the National Leadership scenario in 2050. The yellow dot marks the year with the lowest number of hours, the red dot marks the year with the highest number, and the purple cross indicates the base scenario. The grey dotted line shows the 30-year average.*

The number of battery charging cycles is relatively constant, between 106 and 115 per year. One explanation for this is that batteries are used mainly to cover short-term fluctuations in supply and demand in the electricity system, which occur very frequently throughout every year, regardless of the weather profile. Batteries may be used, for example, at night when there is no solar power, regardless of the weather profile.

The required storage in the hydrogen system shows a different picture. The storage volume required to keep sufficient hydrogen available at all times is three times greater in the year with the most adverse weather profile than it is in the base scenario, and four times greater than in the year with the most favourable weather profile. This is largely related to the flexibility needs in the electricity system. Hydrogen storage makes it possible to flexibly feed the highly variable surpluses in the electricity system into the hydrogen system using electrolysis. Additionally, hydrogen storage enables dispatchable hydrogen plants to produce gigawatts of power over a longer period in times of shortages in the electricity system. This means that fluctuations in the hydrogen system are directly linked to fluctuations in solar and wind power generation.

Figure 17 shows the required hydrogen storage volume for different weather profiles as a result of the imbalance between supply and demand, for the National Leadership scenario. The years where the most (2010) and the least (2018) storage volume is needed are highlighted, as well as an average year (2016) and the basic climate year

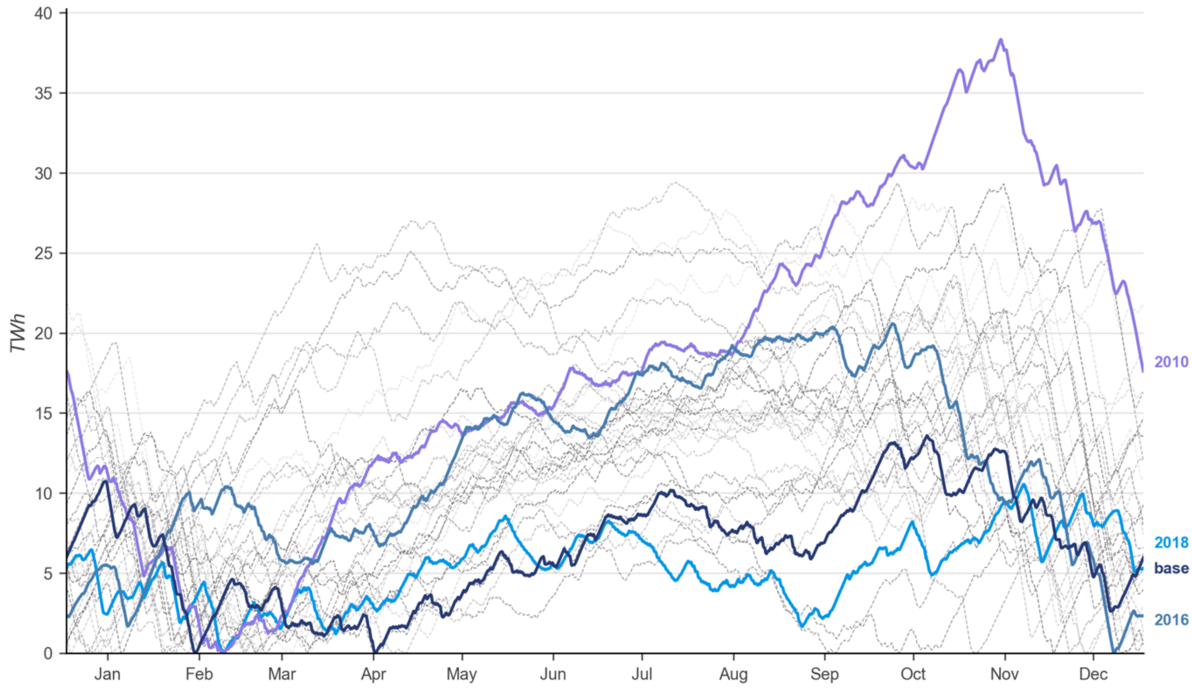

Figure 17: *Change in the amount of hydrogen in storage facilities over the year, for the weather profiles from the1990-2019 period in the National Leadership scenario in 2050.*

During the year when the most storage is needed (2010), there is a period of nearly 10 days with little wind and sunshine available, known as ‘Dunkelflaute’, and hydrogen plants run continuously at full capacity to alleviate shortages. To be able to do so, large volumes of hydrogen have to be kept in reserve to bridge this period.
The required storage volume is, as a result, three times larger than the storage volume in the base scenario.
In the International Trade scenario, where a considerable part of the total heat supply for the built environment is covered using hydrogen, storage needs even rise to above 60 TWh during the year with the most adverse weather profile. Besides fluctuations in solar and wind power generation, temperature fluctuations also have a direct impact on the amount of storage required.

Hydrogen storage facilities show a fairly irregular development over the year, due mainly to the use of electrolysis and hydrogen plants. Methane storage facilities show a classic seasonal pattern in 2050. This is because by 2050 methane will be less closely tied to the electricity system than hydrogen. Methane will be used primarily in industry, in hybrid heat pumps in homes that are difficult to make sustainable, and as a back-up to heat grids. Supply will be steady and consist mainly of fully continuous production of green gas through anaerobic digestion or gasification.

Figure 18 shows the amount of methane in storage facilities during the year for all weather profiles for the National Leadership scenario. The years where the most (2010) and the least (1990) storage volume is needed are highlighted, as is the basic climate year, which is also the average year.

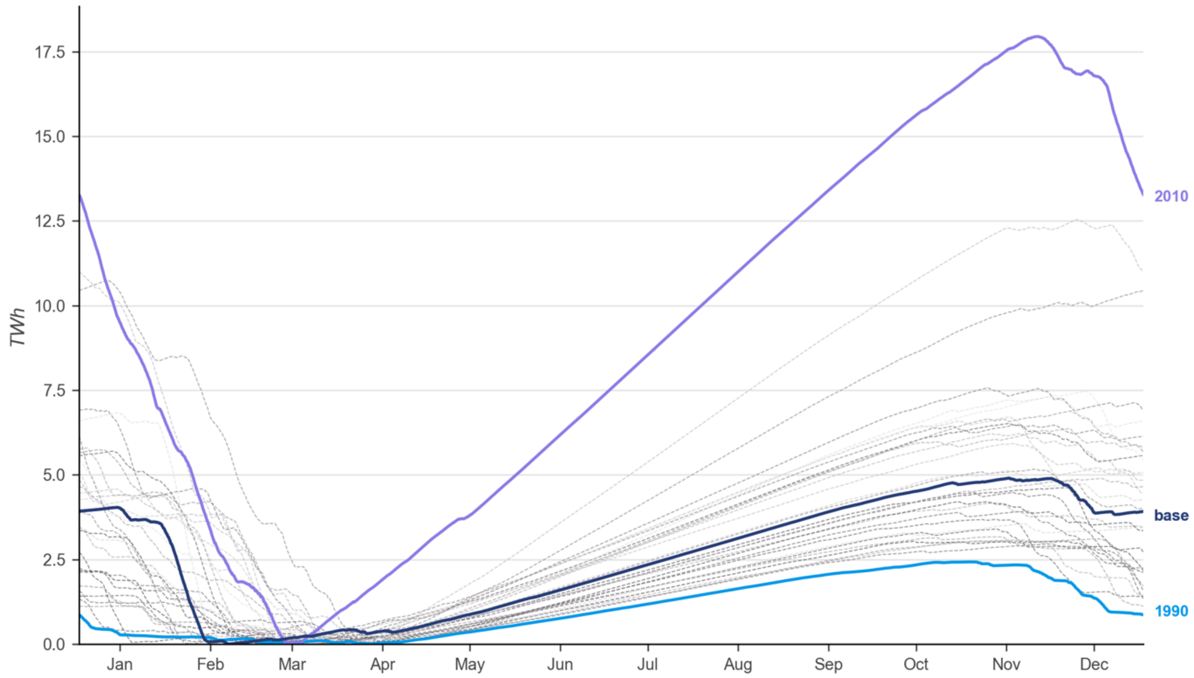

Figure 18: *Changes in the amount of methane in storage facilities over the year for the weather profiles from the 1990-2019 period, in the National Leadership scenario in 2050.*

Methane storage facilities show a classic seasonal pattern, with the highest fill levels around October, extensive demand for methane from the storage facilities over the winter months, and a period after April where storage facilities are replenished. Contrary to hydrogen, demand for methane depends partly on temperatures (demand for heat in the built environment), while supply does not. The weather profile for year 2010 stands out, mainly because this was a year with a very cold winter, with several prolonged periods of sub-zero temperatures.
The average temperature was 2°C lower than in the basic climate year. The large need for storage is caused mainly by two factors. Firstly: hybrid heat pumps in the built environment. These only use gas for heating when temperatures are low. In the 2010 weather profile, consumption is twice as much as in the basic year. Secondly: use of gas as a back-up to heat grids. In the base scenarios, heat sources for collective heat grids - geothermal heat and harnessing residual heat - are set up in a way that allows them to meet demand for heating in a normal year. The low temperatures in 2010 create a shortage of heat of around 15 TWh, which is filled using methane-powered back-up boilers. Figure 19 shows that heat grids also need flexibility and demonstrates the importance of having sufficient options for coping with variations in weather conditions. A further assessment of the required hydrogen and methane storage volumes in the 2030-2050 period is provided in Chapter 6.

3.4.1.4 Back-up heat grids

In the scenarios, heat grids' role in providing the built environment with heating grows significantly, from just 5% of homes connected to a heat grid today to between 10% (in the International Trade scenario) and 30% (in the National Leadership scenario) by 2050. The heat grids of the future are weather-dependent in two ways. Demand for heat is strongly driven by outside temperatures and the supply of heat comes from flexible power-to-heat boilers that convert surplus solar and wind power into heat and, to a lesser degree, solar heat.

The difference in demand for heat between the coldest and hottest weather profile year is just under 40%, with frequent fluctuations of 10% or more year on year. This is comparable to patterns that are currently seen in the temperature-dependent demand for natural gas. The production side is relatively constant: base load demand is assumed to be covered by geothermal heat and residual heat from industry. Alongside that, the production of heat using power-to-heat technologies keeps in step with the availability of wind and solar power.

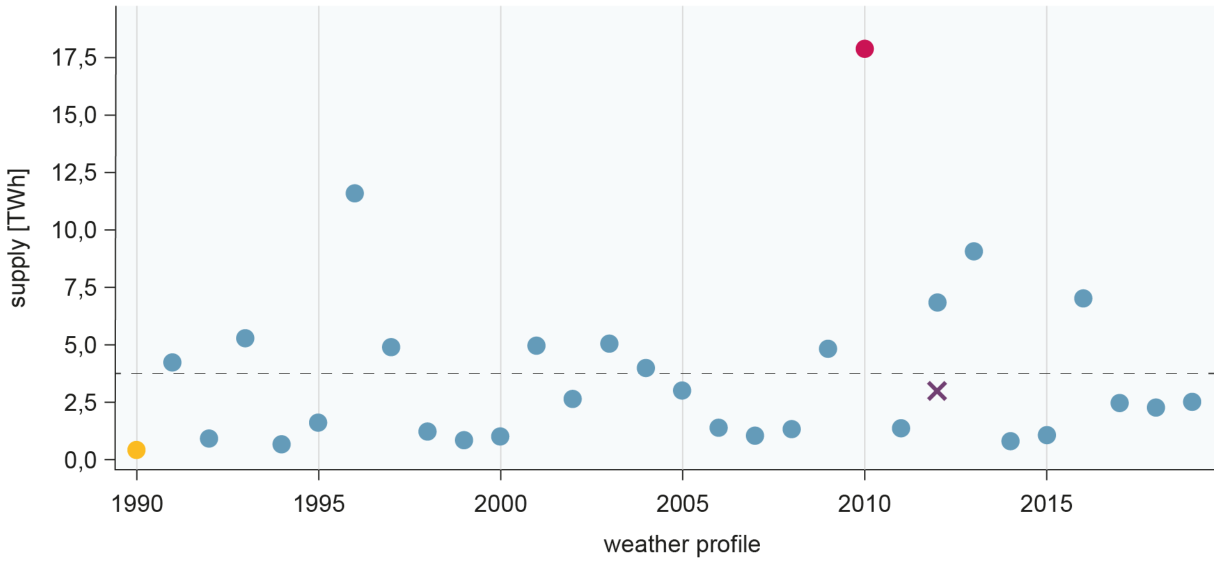

Figure 19: *Heat production by methane-powered back-up boilers for weather profile years from the 1990-2019 period, in the National Leadership scenario in 2050. The yellow dot marks the year with the lowest number of hours, the red dot marks the year with the highest number, and the purple cross indicates the base scenario. The grey dotted line shows the 30-year average.*

In some of the years, using power-to-heat conversion and other heat sources is not sufficient. That is when back-up boilers are needed to prevent shortages. In II3050-2, these back-up boilers are assumed to largely be powered using methane. Figure 19 shows to what extent these boilers are used. There is considerable variation, with several years where the use of back-up boilers exceeds the average by a factor of 2 to 5. The weather profile year 2010 is an outlier, with low temperatures and, consequently, high demand, and little wind and sunshine and therefore little supply from power-to-heat plants. As explained in the previous section on storage, this requires a high degree of flexibility from the methane system, with storage volumes of over 17 TWh needed to keep sufficient methane in reserve. It is quite possible that in the future methane will not be used for this back-up role for heat grids, and that another energy carrier will be used instead, such as electricity, hydrogen or biomass.
In any case, the heat system will need significant volumes of the other energy carriers to alleviate shortages. This is a point to consider in designing the system. High security of supply to cover demand for heat in the built environment is of major societal importance. It is currently subject to strict statutory requirements, such as the requirement that the gas supply must be guaranteed at temperatures down to as low as -17º C. An important

societal issue is, therefore, how to design the heat system of the future. What forms of security should be built in? And what impact will that have on other energy carriers?

3.4.2 Composition of the portfolio of flexibility resources

The composition of the portfolio of flexibility resources chosen for the base scenarios is subject to great uncertainty. There is a considerable chance that interrelationships between future flexible volumes will work out differently than currently foreseen, because there are still many developments ongoing, including in technological and financial areas. This section will analyse how the energy system will behave when assuming more, less or zero capacity of a certain flexibility resource in comparison to the base scenarios, looking at the National Leadership scenario in particular. For each scenario variant analysed, one single flexibility technology is altered and the other assumptions are kept constant.

The following two observations recur throughout the analyses. First of all, the effect on the shortages that arise in the electricity system as a certain flexibility technology is reduced or eliminated altogether is often considerable in terms of capacity but limited in terms of volume. At peak times, shortages arise of several gigawatts of capacity (around 5-15 GW), but these situations occur only for a limited number of hours, meaning that only a small part of demand cannot be met, namely around 0.1 to 0.2% of annual demand and several dozen hours per year.
The same conclusion was drawn in the previous section on weather conditions. Investments in back-up capacity and redundancy are crucial if we want to balance the energy system when facing adverse or unexpected circumstances. Part of these flexibility resources will then be needed for only a limited number of hours per year. With the way the market is currently organised, it is not a given that these flexibility resources will be profitable and that the market will make the necessary investments in sufficient back-up capacity.

There is, of course, an explanation for this combination of large capacity and small volume. Due to the large volumes of energy that will be generated from wind and solar in 2050, the number of hours with shortages will be limited anyway, namely around 30% of the hours in a year. In the National Leadership scenario, shortages of over 25 GW occur in under 10% of the hours. On top of that, there is around 100 GW of supply flexibility in the form of batteries, interconnection capacity, dispatchable power plants, and industrial demand response available to cover shortages. Not all this capacity is available at all times: imports are not available as an option, or only to a limited degree, at times of scarcity in neighbouring countries. Batteries have limited storage capacity and have to be charged first before they can be used. Industry is not always able to reduce or interrupt their demand. Nonetheless, whenever a certain flexibility resource ceases to be available or has reduced availability, shortages can largely be covered by increasing the use of the flexibility resources that *are* available. Only during the hours with the highest peaks, this will not work and all the available flexibility resource capacity will be needed to keep the system up and running.

A second observation is that reducing the use of a flexibility resource or not using it at all has an effect on the energy system that goes beyond merely creating shortages in the electricity system. Flexibility resources affect the hourly electricity price and, with that, also the deployment and operating hours of other flexibility resources. Limiting the use of a flexibility resource not only potentially leads to shortages, but also leads to changes in the operating hours of demand flexibility resources such as electrolysers, or in the times when batteries are charged and used. The energy system with flexibility mechanisms is a complex system with numerous interacting and interdependent variables, for each energy carrier and across the various energy carriers. Choices for one aspect of the energy system can have major consequences for other aspects, meaning that system choices and flexibility resources cannot be viewed in isolation.

3.4.2.1 Demand side response in industry

Industry can play a crucial role in balancing the electricity system by reducing or interrupting their consumption during times of scarcity. In the base scenario, the assumption is that 50% of the peak capacity of industry is interruptible. This is an ambitious assumption, partly because only a very small portion of the total demand for electricity from industry is dispatchable at this point.

The two charts of Figure 20 below show the extent of the shortages that arise in the electricity system when demand side response (DSR) in industry stays below the 50% assumed in the base scenarios. The assumption is that the installed capacities of the other flexibility resources are unchanged. The results are shown for the National Leadership scenario (2050).

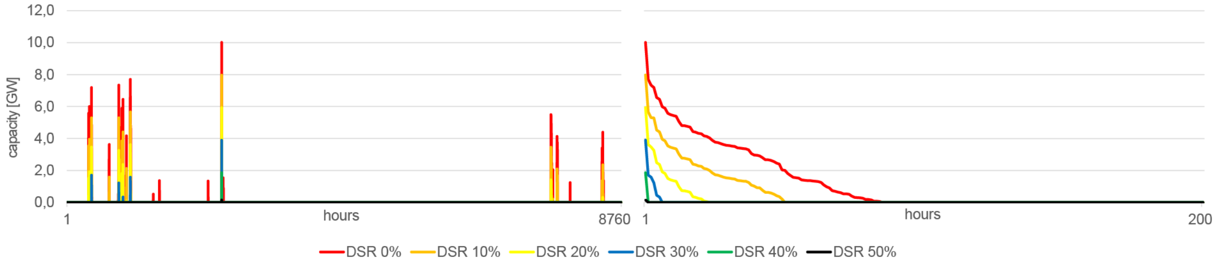

Figure 20: *Hours with shortages when varying the industrial DSR potential (capacity) in the National Leadership scenario in 2050*

In the base scenario (DSR 50%), there are no hours with shortages. If DSR is reduced, both the number of hours with shortages and the associated shortage capacities go up. If industrial demand does not respond flexibly at all (DSR = 0%), the scenario analysed would have shortages of up to 10 GW during a total of 85 hours (1% of the year).

The areas below the curves in the right-hand chart show the volume of electricity that has not been supplied. Even in the most conservative version without flexible industrial demand (DSR = 0%), there is only a maximum shortage of around 245 GW that cannot be covered. This is 0.1% of total demand for electricity.

The capacity may have an impact on the ability to bridge shortage situations, but so does the assumption about the maximum time span during which demand reduction is possible. The two charts of Figure 21 show shortage capacities and hours when varying the maximum connected time span where industrial DSR is available.

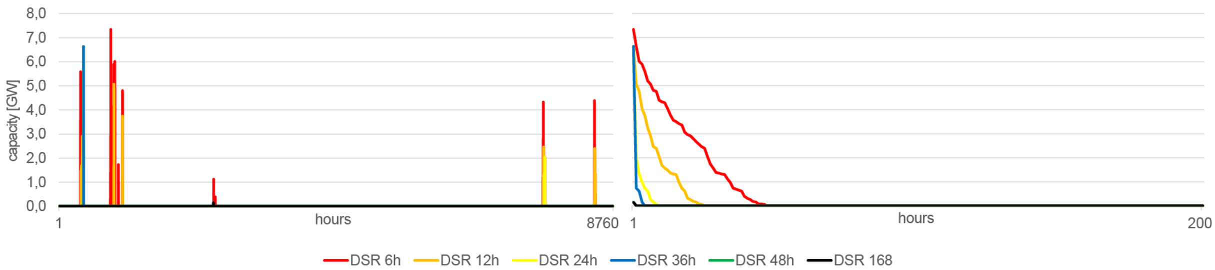

Figure 21: *Hours with shortages when varying the industrial DSR time span (volume) in the National Leadership scenario in 2050*

As the analysis shows, the shorter the period during which demand for electricity in industry can be reduced to the maximum degree, the higher both the potential shortage capacities and volumes, and, consequently, the greater the need for alternative flexibility resources. The maximum is 7.5 GW with the most conservative DSR of 6 hours, which means 47 hours with shortages (< 0.5% of the year) and 125 GWh of volume (< 0.1% of total demand for electricity).

Given that the assumption is that DSR is the most expensive option in the 'merit order' during most hours, limiting DSR has little to no effect on the behaviour of other flexibility resources, such as power plants and batteries.

3.4.2.2 Interconnection capacity

The Netherlands is part of the European energy system with electricity connections to Germany, Belgium, the United Kingdom, Denmark and Norway. Given European market integration, sustainability ambitions and security of supply aspects, further expansion of existing connections and new cross-border connections have been planned for the future. In the longer term, there is still uncertainty about the extent of interconnections between electricity markets. With this in mind, the National Leadership scenario for 2050 was used as the basis to analyse what impact a potentially smaller or larger scope of electrical transfer capacities would have on the domestic need for flexibility.

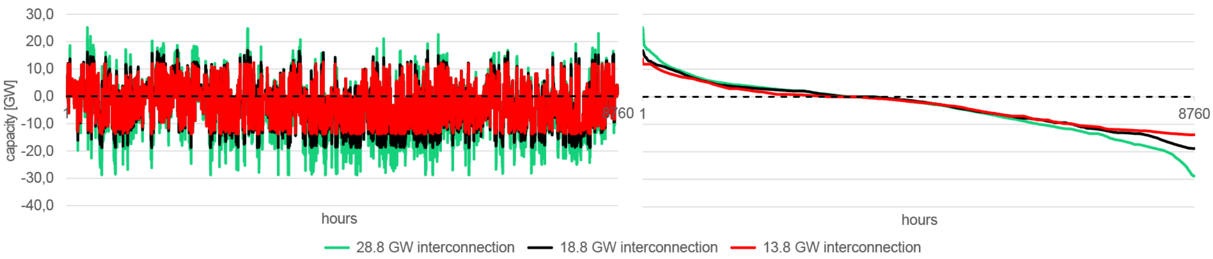

Figure 22: *Market transfers with other countries in the National Leadership base scenario in 2050 and in the variations on that scenario.*

Figure 22 shows, per hour, the total electricity transfer in the base scenario (interconnection capacity of 18.8 GW) and the low (capacity of 13.8 GW) and high (capacity of 28.8 GW) variations on that scenario. Positive values indicate that electricity is imported, while negative values indicate that electricity is exported. In the right-hand figure, these transfers are sorted by size, from large to small. What is instantly clear is that greater maximum transfer capacity leads to increasing use of this capacity. This increase relates mainly to capacity during a few hours, while the volume is reasonably comparable.

Table 7 below shows the system impact of expanding interconnections to 28.8 GW, limiting interconnections to 13.8 GW, and an extreme scenario without any interconnections. The percentage deviation shown here is the deviation from the basic National Leadership scenario in 2050.

Table 7: *System impact of various interconnection levels for the National Leadership scenario in 2050.*

Re	28.8GW	13.8GW	No interconnections
Shortages			
Peak shortage (GW)	0	1	7
Volume (GWh)	0	4	220
Number of hours	0	10	95
Electricity price	- 2%	+ 1%	+ 10%
Operating hours of hydrogen plants	- 1%	+ 7%	+ 23%
Operating hours of electrolysis	- 5%	+ 4%	+ 20%
Operating hours of power-to-heat	- 2%	+ 2%	+ 9%
Curtailment	- 7%	+ 6%	+ 40%

Limiting the interconnection capacity to 13.8 GW leads to minor shortages in the electricity system, for 10 hours and with a maximum capacity shortage of 1 GW. If there are no interconnections at all, the shortages increase significantly, with peaks of up to 7 GW spread over 95 hours. In both variants, the shortage volume, the total amount of electricity that cannot be supplied, is small: 4 and 220 GWh respectively, against a final use of 300,000 GWh (maximum of 0.1%). This is partly because other flexibility resources, such as hydrogen plants, will be used more when interconnections are reduced or become unavailable, with 7% and 23% more operating hours respectively.

Limiting interconnection has an adverse impact on the price of electricity. On average, the price rises by 1% in the variant where interconnections are limited (13.8 GW) and by 10% in the variant without interconnections, while the price actually drops by 2% when upping interconnections to 28.8 GW. This is in line with the expectation that interconnections will lead to a larger and, consequently, more efficient market area. A similar trend is visible for curtailment, reducing electricity production from renewable sources when there are major supply surpluses. Expanding interconnections makes it easier to export surpluses. This means that 7% less curtailment will be needed when expanding interconnections and 6% and 40% more, respectively, when limiting interconnections and when there are no transfers to and from other countries at all.

The operating hours of electrolysis and power-to-heat systems go down when expanding interconnections and go up when limiting interconnections. There are two opposite effects here. On the one hand, better connections to other countries bring more competition at times of ample supply and low prices: besides domestic demand flexibility, foreign parties will also be interested in the cheap power. More interconnections will then lead to fewer operating hours for domestic flexibility resources. On the other hand, domestic demand flexibility can take advantage of times when prices are low in other countries. More interconnections will then lead to an increase in the operating hours. In the scenario variants that were analysed, the first of these two effects dominates: domestic demand flexibility resources operate for fewer hours, on a net basis, when there are more transfers to and from other countries, and vice versa.

What is important to note here is that in the above analysis only the interconnection capacity changes; the other installed capacities are assumed to be the same as in the base scenario. In reality, it is self-evident that significant changes in the available interconnection capacity mean that the wind and solar power production park and the portfolio of other flexibility resources would also be shaped differently. Additionally, the calculation model used does not offer the option of running a complete, integrated European market calculation. The analysis is, therefore, intended primarily to show the sensitivities and variability with alternative flexibility assumptions.

3.4.2.3 Batteries

The base scenarios assume that batteries will develop significantly. By 2050, the total battery capacity may be between 40 and 70 GW. Table 8 below analyses the system impact when limiting battery capacity by 33%, 66% and 100% compared to the base National Leadership scenario in 2050.

Table 8: *System impact of different battery capacities for the National Leadership scenario in 2050*

Re	33% less	66% less	No batteries
Shortages			
Peak shortage (GW)	4	7	13
Volume (GWh)	30	130	630
Number of hours	20	60	145
Electricity price	+ 22%	+ 58%	+ 140%
Operating hours of hydrogen plants	+ 27%	+ 37%	+ 54%
Demand interruption in industry	+ 58%	+ 75%	+ 97%
Net electricity import	+ 14%	+ 25%	+ 40%
Operating hours of electrolysis	- 1%	- 2%	- 6%
Operating hours of power-to-heat	+ 5%	+ 11%	+ 23%
Curtailment	+ 130%	+ 194%	+ 280%

Limiting battery storage leads to major peak shortages in the electricity system, from a maximum of 4 GW with 33% fewer batteries to 13 GW in the scenario without any batteries. Like with the interconnection variants, the shortage volume, i.e. the total amount of electricity that cannot be supplied, is small: 30 to 630 GWh, spread over 20 to 145 hours. Given a final use of 300,000 GWh, this represents 0.2% of annual demand. The explanation is also the same: other flexibility resources, such as hydrogen plants, electricity imports and demand interruption in industry, are used more when there are fewer batteries, so shortages can largely be prevented.

Reduced battery storage has a significant impact on electricity prices. In the scenario with a third less battery storage, the annual average electricity price is 22% higher than in the basic version. When there are no batteries at all, this is even as much as 140%. This is partly because brief shortages cannot be bridged using batteries as often, or not at all. That means that flexibility options with higher marginal costs will have to be used, such as hydrogen plants, industrial demand response, or imports at times when there is also scarcity in other countries, meaning that prices will be high. Price variability also increases when there is less battery storage capacity available. Batteries are charged when prices are low and power from batteries is used when prices are higher. This way, they level out the price curve: they create additional demand in times of ample supply and additional supply in times of great demand. Table 8 shows that reducing battery storage capacity will, on the one hand, lead to an increase in the number of hours with shortages, i.e. hours with major scarcity and very high electricity prices. On the other hand, curtailment will increase sharply, by between 130% and 280%. At these times, there is actually a major surplus of supply and the price of electricity drops to 0. Electricity price peaks and troughs will, as a result, become more frequent and be more extreme.

The operating hours of electrolysis and power-to-heat technologies show a mixed picture. Electrolysis will run 1% to 6% less than in the base scenario, while power-to-heat technologies will be operational 5% to 23% more. This is because of the assumption made in II3050-2 that willingness to pay is higher for electrolysers than for power-to-heat technologies. Batteries ensure that the supply of electricity produced from renewable sources is spread more evenly over time, bringing down the number of times that major surpluses arise and prices are very low. Electrolysis is thus enabled to run more constantly and for more hours, albeit to a limited degree. When it comes to power-to-heat technologies, the assumption is that this flexibility resource will only start running when the price of electricity is very low (< 20 euros per MWh). As described above, less battery storage capacity leads to greater electricity price volatility, meaning that prices will be very low more frequently and that there will be more opportunities for power-to-heat plants to take advantage of these low prices.

The same caveat as with the interconnection variants applies to this analysis. Supply and other flexibility resources were not (re)optimised, and so the resulting energy system in the variants analysed is less well balanced than in the base scenarios. The analysis is, therefore, mainly intended to show the sensitivities and variability with alternative flexibility assumptions.

Cost assessment for dispatchable power plants and industrial demand side response

In the II3050 scenarios, dispatchable hydrogen-powered electricity plants and interrupting demand from industry are the final two options in the merit order whenever shortages arise in the electricity system. This means that these flexibility options are deployed when shortages, and the resulting electricity prices, reach such levels or are so prolonged that other options, such as batteries, are not adequate to alleviate the shortages. This box will further zoom in on the costs of hydrogen plants and demand response.

The costs involved in balancing supply and demand using hydrogen plants vary based on the number of hours of operation and hydrogen prices. The lower the hydrogen prices and the higher the annual hours of operation, the lower the total costs per megawatt hour of electricity supplied. The graph below shows this correlation for various hydrogen price levels and numbers of hours of operation. The measure used is the levelised cost of energy (LCOE), which is a measure of total production costs during the service life of a power plant.

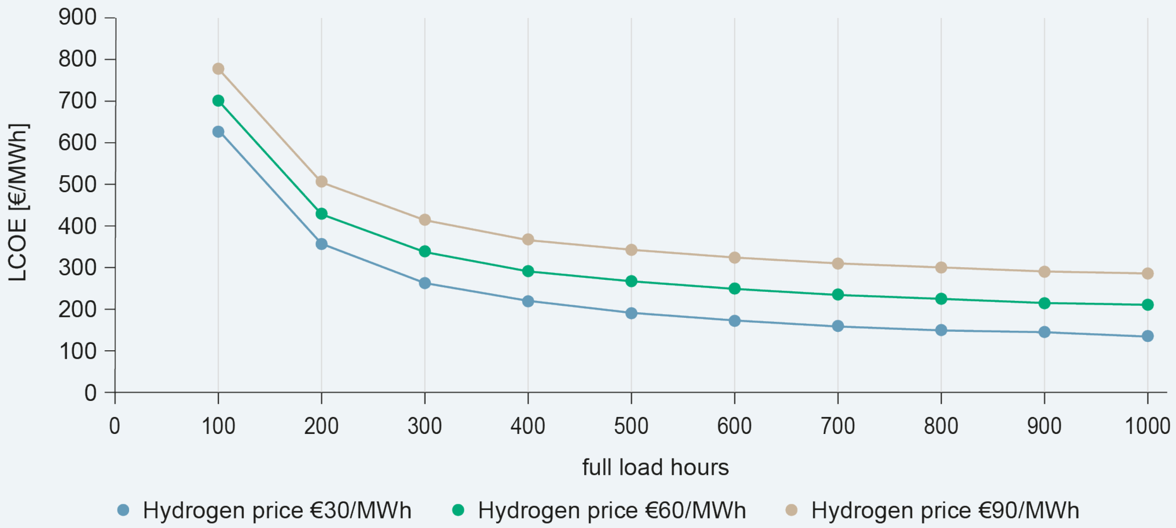

Figure 23: *Levelised cost of energy (LCOE) for hydrogen peak plants with varying hydrogen prices and full load hours.*

At 100 full load hours per year, the costs per megawatt hour produced range from 600 to 800 euros. At 1,000 full load hours, the costs are between 130 and 280 euros. In the National Leadership scenario, hydrogen peak plants run for approximately 850 full load hours (140-290 euros) to produce 12 GW. If the 10 GW of industrial demand response assumed in this scenario were replaced with hydrogen peak plants, hydrogen plants would run for roughly an additional 300 full load hours to produce this additional 10 GW of power. The graph above shows that the total costs of electricity from hydrogen plants range from 250 to 400 euros per MWh at 300 full load hours.

For industrial demand response, it is harder to make such a cost estimate, partly because so little is known as yet about the potential and the implementation of demand response in industrial processes. Industrial processes are very diverse, ranging from steel making to steam cracking to paper manufacture. The costs involved in a demand side response vary greatly from one process to another. TenneT's recent 'Monitoring Leveringszekerheid' (Security of Supply Monitor) publication estimates a cost bandwidth based on the available literature. Assuming 300 full load hours, this bandwidth goes from 20 to 230 euros per MWh, based on current use of DSR in Europe. A 2020 study by DNV GL estimates that there will be just under 2 GW of industrial demand response available in the price range from 0 to 500 euros per MWh in the Netherlands in the year 2035. After that, costs start to rise sharply. In the range between 500 and 2,000 euros per MWh, there will also be around 2 GW available, as well as in the range of 2,000 to 8,000 euros per MWh.

The European Integration and International Trade scenarios assume 4 GW and 3 GW of industrial demand response respectively. Based on the results of the DNV GL study for 2035, it is quite conceivable that such capacities will be attainable in a cost-effective way by 2050, especially if demand flexibilisation becomes a fixture in the design of new business processes. The Decentral Initiatives and National Leadership scenarios project higher capacities, of 8 GW and 10 GW of flexible industrial demand respectively. In the National Leadership scenario, this represents nearly 50% of industry demand capacity (peak capacity of 21 GW). In these two scenarios, there is greater uncertainty as to whether such flexibility capacities are feasible and what it will cost. Further research will be needed to estimate the costs involved in such major flexible capacities in 2050.

3.5 Regional impact

This section will delve deeper into the effects of flexibility on a regional level. As described in Chapter 2, all energy demand, supply and flexibility resources from the base scenarios are broken down by region across the country. Flexibility resources are 'regionalised' based on smart heuristics to make sure there is demand flexibility in areas with frequent surpluses and supply flexibility in areas with scarcity. The regional deployment of all flexibility resources, however, follows a national pattern, meaning that considerable energy transport between the various regions of the Netherlands will continue to be required. This analysis looks at four clearly demarcated geographical areas that are exemplary for the future energy landscape: a rural area, an urban area, an industrial area and a landfall point for offshore wind power. The question: how does flexibility affect the local balance between supply and demand in these areas?

The analysis shows that the local balance of supply and demand can differ greatly between geographical areas. While local flexibility resources help reduce the local imbalance during many hours of the year, there are also times when national price incentives actually cause flexibility resources to add to the local imbalance instead of reducing it, which leads to an additional need for transport. Chapter 8 will further look into how controlling flexibility on a local scale can temper peaks on the grid. This concerns a relatively small number of hours of the year, during which national price incentives are not in line with the local situation. For a detailed analysis of the effect of flexibility on various regional levels and in different exemplary regional areas, see Appendix D.4.

Rural area

Rural areas are areas with villages and small towns, relatively low population density, and space for agriculture and nature. Demand for electricity is, therefore, relatively low and comes mainly from farms, transport and the built environment. On the supply side, wind and solar power generation often significantly exceeds annual demand, by a factor of 1.5 to 2.5. When viewing the situation on an hourly basis, however, the picture changes. Solar power produces major surpluses during a limited number of hours, while there are actually shortages at other times. This is illustrated by Figure 24.

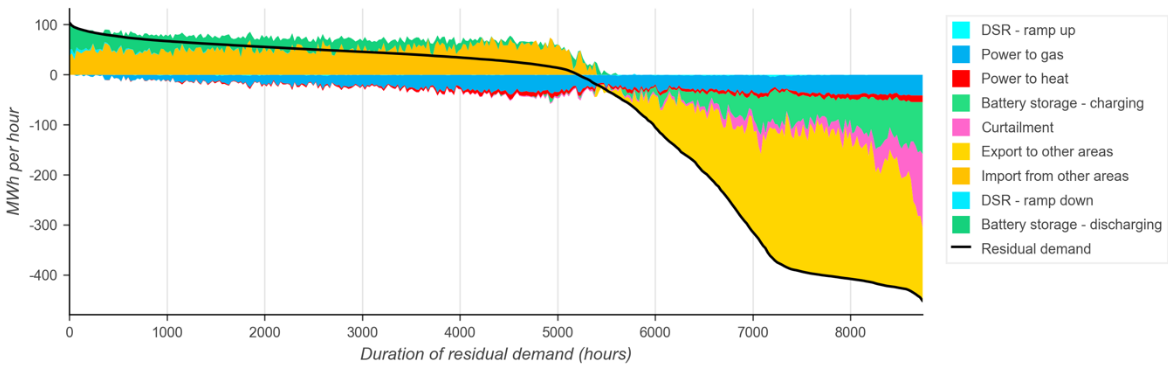

Figure 24: *Residual demand and use of flexibility for a rural area in the National Leadership scenario in 2050.*

The chart shows a residual load duration curve, which was introduced in Section 3.3, for an exemplary rural area. For most of the year, electricity demand exceeds supply (approximately 5,200 hours above 0). This is solved by using power from batteries (green area) and by getting power from other areas (yellow area). The rural area is also home to electrolysers that follow a national deployment profile. These actually add to local shortages at some times, i.e. when the electrolysers are operational while there is insufficient power being generated locally. As a result, additional power will have to be obtained from outside the area (the yellow area above the black line), which means an additional need for transport.

During roughly 3,000 hours, surpluses arise because of the ample space for solar power generation in rural areas. To a limited degree, these surpluses can be used locally by charging batteries (green), operating electrolysers (blue), and converting power into heat (red). During the hours with the highest peaks in generation, some solar power production is shut down (pink). However, due to the limited local demand, most of the surpluses are transported to other areas (yellow area). The resulting need for additional transport dominates compared to transport needs during the other hours of the year.

For the sake of readability, Figure 24 shows a simplified view of the 8,760 hours in a year. The underlying hourly values show that, during the peak hour, roughly 90 MWh of power for this rural area has to be obtained from surrounding areas to meet basic demand. This is after deducting local solar and wind power production and local flexible supply from batteries, power plants and demand response. Without flexible supply, the peak would have hit 111 MW. Therefore, flexible supply reduces the peak shortage by over 20% in this area.

However, there are also hours when local flexibility resources actually add to the shortages. During roughly 900 hours of the year, the local shortage exceeds 90 MWh per hour because local power-to-gas systems, power-to-heat systems and batteries worsen the local imbalance. As a result, more power from outside the area is needed than if there were no local flexibility resources at all. And this, in turn, is because these flexibility resources in the models used here respond to national price incentives and do not take account of the local situation. Limiting demand flexibility during these hours means that 15 GWh of flexible demand cannot be met. This is 3% of the total flexible demand in the area (440 GWh). Chapter 7 will further look into how limiting local flexibility during a limited number of hours can help reduce grid congestion.

Urban area

Cities have high building density, industrial areas, and a lot of passenger and goods transport. There is limited space available for wind and solar farms, but there is great potential for solar power generation on roofs.
This combination of high demand and low supply causes shortages for most of the year. This is illustrated by Figure 25.

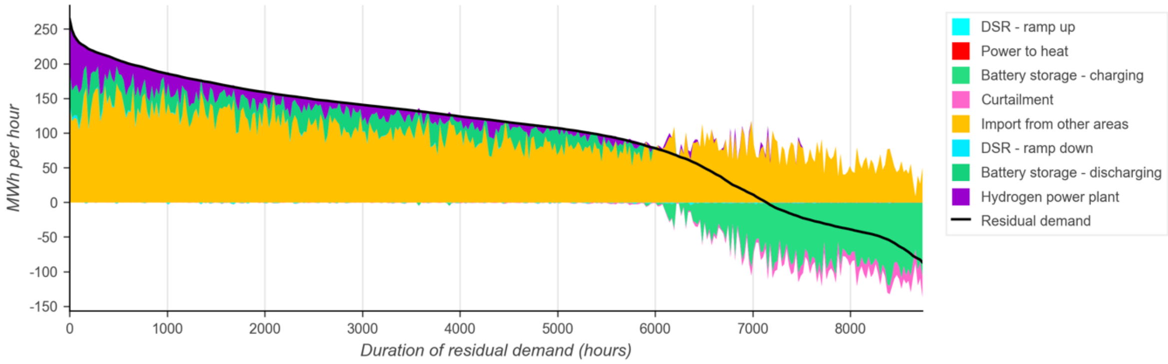

Figure 25: *Residual demand and use of flexibility for an urban area in the National Leadership scenario in 2050.*

The urban area has shortages for roughly 7,000 hours of the year, with surpluses arising only during very sunny hours. During times of shortages, the area relies heavily on imports from other areas (yellow area).
The dispatchable power plants in the city follow a national deployment profile. They help reduce shortages, but they do not always operate when there are shortages because this is not necessary from a national perspective. Batteries also contribute significantly to reducing the shortages, but substantial imports from outside the city are still needed to meet demand. What also stands out is that even when there are surpluses, considerable amounts of electricity are still imported from outside the city. This is because the local surpluses are not enough to charge the batteries to a sufficient degree.

Industrial area

There are five clusters with energy-intensive industry in the Netherlands. The processes of the basic industrial companies based in these clusters require a lot of energy and feedstocks to make steel and fertiliser, for example, and for refinery operations and chemicals. The potential supply of solar and wind power is limited in some of these clusters, while others are located close to an offshore wind power landfall point. Figure 26 below shows a cluster that is not located near an offshore wind power landfall point. As a result, it has to meet the lion's share of its demand for power using power generated in other areas.

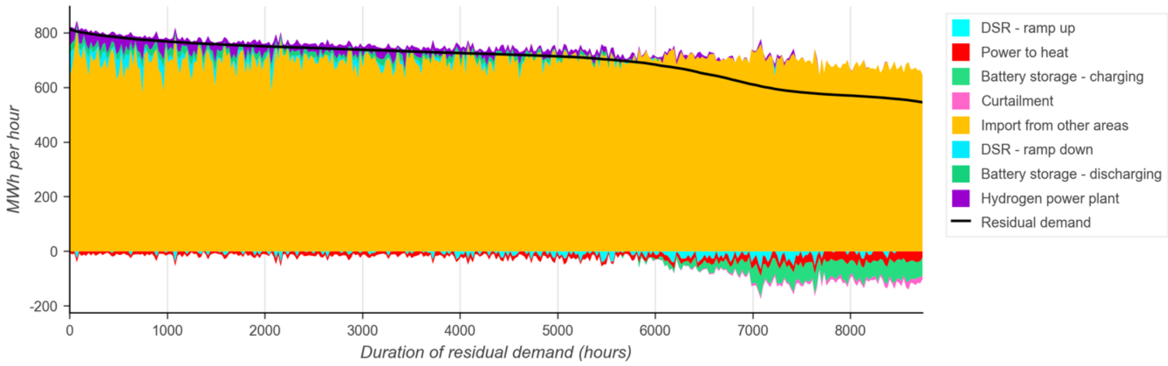

Figure 26: *Residual demand and use of flexibility for an industrial area in the National Leadership scenario in 2050.*

Due to base load demand from industry, the residual demand curve is fairly flat throughout the year. Industrial demand moves in step with national supply and demand - consumption is reduced when there are shortages and increased when there are surpluses - but the impact is limited. Power from dispatchable power plants and batteries is used mainly during peak shortages. However, the industrial area relies heavily on imports from surrounding areas, due to the limited possibilities for local power generation and the limited space available for flexibility resources. The next section will examine the situation of an industrial cluster near a landfall point for offshore wind power.

Offshore wind power landfall point

Along the Dutch coastline, there are various points where offshore wind power can be fed into the onshore grid. It is also conceivable for these locations to be further inland. At some of these landfall points, large amounts of wind power are fed into the grid. This leads to a surplus of energy at these locations, both in terms of capacity and in terms of volume. II3050-2 has opted to install a large number of flexibility resources in these areas to make the most of the surpluses as close to where the energy is generated as possible.

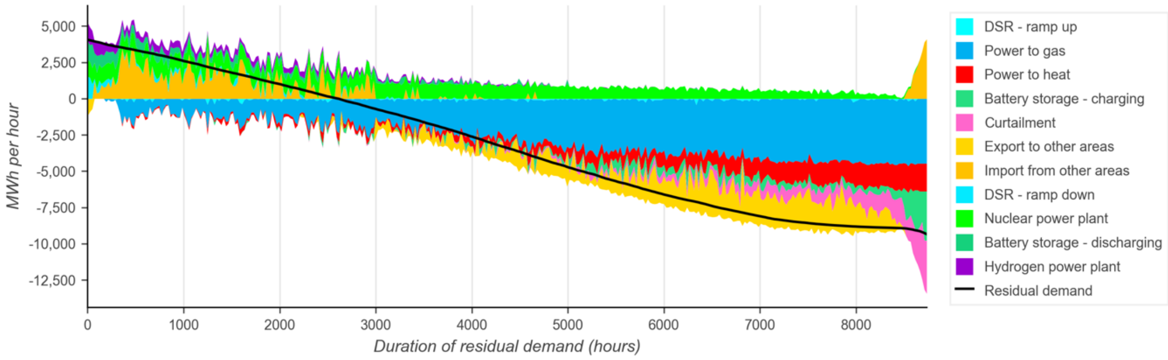

Figure 27: *Residual demand and use of flexibility for an offshore wind power landfall point in the National Leadership scenario in 2050.*

Figure 27 above shows residual demand and use of flexibility resources at the Maasvlakte industrial park, which is a point where large volumes of offshore wind power are brought ashore. While this area is home to large-scale energy-intensive industry, there are surpluses for most of the year (6,000+ hours) due to the large volumes of offshore wind power. Surpluses are used by activating electrolysers (blue), operating power-to-heat units (red), and charging batteries (green). Two situations stand out:

- Even at times when there are no local surpluses, the electrolysers are operational. This creates a transport need for imports from other areas. This situation is caused by the fact that the electrolysers follow a national deployment profile. This landfall point is mainly for wind power, but nationwide electrolysers also run when there is little wind and a lot of sun. This results in a transport need with peaks that are higher than they would be if no flexibility resources were used at all in this area.

- During the hours with the largest surpluses (the right side of the graph), there are so many surpluses nationally that the price of electricity drops to zero. This national price movement can lead to offshore wind power production being shut down temporarily. Additionally, the low prices lead to electrolysers and power-to-heat plants being activated and batteries to start charging. This can, in turn, lead to situations where local production is shut down, meaning that there is not enough electricity locally available for the flexibility resources. In this case, redispatch or imports from surrounding areas will be needed to balance the local situation.

Part 2

Energy infrastructure

Chapter 4

Overarching starting points for the network analyses

4.1 Introduction

An important objective of this outlook is to paint a broad picture of the energy networks that will be necessary in 2050 for the scenarios set out in Chapter 2. Energy networks connect the supply of an energy carrier (through domestic production, imports, retrieving energy from storage facilities, and conversion from other energy carriers) to the demand for an energy carrier (for domestic energy consumption, exports, filling storage facilities, and conversion into other energy carriers). They enable transport of energy and thus constitute a substantial link in the energy system.

The Netherlands has national electricity and gas transport infrastructure with international connections. Aside from that, there are extensive regional distribution networks for electricity and gas, as well as regional and local heat grids, the latter mainly in urban areas. These national and regional infrastructures are interconnected in several ways, including on a national level through gas supply to power plants, on a regional level through cable and pipeline connections between regional network operators and, for example, through district heating boilers.

The energy transition is a major challenge for the operators of these networks, because both the sources of energy and the end use of energy are set to change drastically. This means that networks will have to be expanded, connected differently, repurposed for the use of other energy carriers, but also removed altogether when existing infrastructure is no longer needed. This is a challenge for every single network operator. There is, however, also a clear interrelationship between the tasks that the network operators face that means that a joint approach is required based on shared starting points. These starting points are described in Section 4.2.

4.2 General starting points for the design of the infrastructure

Chapters 2 and 3 already described the choices made for determining the expected scope of supply and demand, i.e. the regionalisation and profiles). Next, the focus shifted to the need for flexibility, formulating assumptions on the deployment and location of flexibility resources. These choices help define the scope of the transport infrastructure that will be needed for the various energy carriers. However, there are more choices that have to be made before a transport analysis can be conducted. Some of these choices are almost tacitly assumed.
For others, it is good to agree on them beforehand and be clear on the starting point for calculations.
This concerns the following topics:

- Working on the basis of an integrated energy system.
- Integrated planning versus planning for each network individually.
- The energy system in a European context.
- Existing and new infrastructure.
- Security of supply and reliability.
- Weather and climate.
- Interrelationship with carbon and heat supply chains.

The following provides an explanation of the choices made for the purpose of this outlook.

4.2.1 Working on the basis of an integrated energy system

Just like in the first edition of II3050, this second edition has chosen to include all energy carriers and the interaction between those energy carriers in the outlook. The energy system will have to be set up in such a way that energy supply and demand are interlinked and differences in supply and demand are levelled out. There can be differences in terms of energy carrier, time or place. A difference in supply and demand for an energy carrier can be levelled out by converting an energy carrier into another energy carrier, a difference in time by storing energy or using supply and demand response, and a difference in place by transporting energy elsewhere through cables and pipelines. These ways of levelling out differences are interrelated and affect each other. The volumes and use of flexibility resources and their location partly determine the amount of an energy carrier that will have to be transported. This given lies at the basis of system integration. By carefully coordinating the transport, storage and conversion of energy carriers, the energy system can be set up efficiently (see also Chapter 10).

This outlook centres on the development of energy infrastructure on land, because electricity infrastructure in the North Sea is currently still radially (directly) connected to the high-voltage grid and most of the infrastructure for hydrogen and CO_2 is yet to be developed. Nevertheless, it is clear that there will be interconnections between onshore and offshore networks and that system integration effects that can lead to a better design of the complete energy system (both onshore and offshore) can also be taken into consideration when developing infrastructure offshore. One example is the use of electrolysis at sea after 2030 and the hybrid connection of this to the networks on land (Chapter 10).

4.2.2 Integrated planning versus planning for each network individually

For this outlook, network operators first independently conducted their own network analyses, and subsequently looked jointly at system integration based on specific cases. While the approach with separate, independent network analyses is challenging due to the differences in methods and principles used, II3050-1 showed that it can still lead to a consistent picture. For this second edition, the network operators again agreed on the methods to use, so that results could be effectively aligned in this outlook as well.

All the network models used were properly validated, including through intensive use in the two-year investment planning cycle. The models, therefore, deliver the best possible results for this outlook as well. The analysis for this study may, however, deviate from the analysis made for an investment plan, for example, because this study uses a central set of drivers (technologies), regionalisation and profiles. Network operators mainly draw input for their investment plan from their own regionalisation and profiles compiled based on bottom-up information, including known plans from their immediate environment and customer information.

Following the independent network analyses, solutions for system integration are also identified. Integrated network models that enable a bottleneck and investment analysis for the combined networks are not yet of sufficient quality, which is why this outlook assesses system integration by detailing a number of specific cases. These cases look at ‘cross-network’ effects that are visible only in a joint analysis. These cases are presented in Section 10.4.

4.2.3 European context

This outlook is focused on an energy system for the Netherlands that is connected to the countries around us. These connections are not only physical, i.e. cross-border cables and pipelines, but also a result of the creation of a European energy market with the associated regulation. The Dutch national network operators TenneT and Gasunie in particular are closely involved in all European developments in this context, including through their membership of the joint transmission system operator (TSO) associations ENTSOG and ENTSO-E.

A key starting principle in the European context is that the networks must give users non-discriminatory access, as a result of which the current national networks for gas and electricity are decoupled entry/exit systems. For the purposes of the calculations, it is assumed that it will stay this way in the future and that the principle of decoupled entry/exit will also be used for the national hydrogen network.

ENTSOG and ENTSO-E focus on, among other things, modelling interconnections to further explore the transfer of electrons and molecules between the countries. Given that the Netherlands has the potential to develop into a hub between the North Sea and the rest of Europe, the focus is on connections to countries around the North Sea and in north-western Europe. In the data used for the network calculations in this outlook, import and export (power, gas and hydrogen; volumes and locations) were aligned with European figures and plans.

4.2.4 Existing and new infrastructure

A large part of the infrastructure for electricity and gas is existing infrastructure, most of which has not yet reached the end of its technical life. The obvious choice is, therefore, to keep using all these existing pipelines, cables and substations and to add new infrastructure as necessary to be able to accommodate supply and demand in the future as well. Taking existing infrastructure as the starting point in planning the energy system of the future is referred to as the ‘brownfield’ approach.

The alternative is a ‘greenfield’ approach, where infrastructure is designed and built from scratch, without taking existing infrastructure into account. Since a large part of the existing infrastructure and the space it occupies can also be used in the future situation, a decision was made not to use the greenfield approach, as it would be unnecessarily costly and involve a lot more work. That being said, taking the brownfield approach does not rule out the building of new connections; the starting point is effectively ‘brownfield, unless...’

The choice for the brownfield approach guides, for example, the development of the national hydrogen network, which is expected to consist largely (80%) of repurposed natural gas pipelines by 2030. Besides reusing pipelines from the existing natural gas network, another option is to reuse other parties’ pipelines, such as pipelines that were used to transport oil, naphtha, kerosene and brine in the past. These pipelines are, however, generally less well suited for hydrogen transport, partly because they are contaminated or corroded, and/or the diameter is too small, i.e. they do not offer enough capacity.

In fact, the principle of reuse is also relevant to the electricity network, for example when it comes to the space occupied by current power transmission lines.

4.2.5 Security of supply and reliability

Security of supply is the degree to which sufficient energy is supplied at all times. The calculations for this outlook assume that the current high level of security of supply has to be maintained throughout the transitional period and beyond that.

Security of supply is created by having sufficient production and transport available. Given that network operators are responsible for energy transmission, they play a key role in maintaining security of supply. A reliable network, i.e. a network with low susceptibility to outages, contributes to a high security of supply.

Since absolute security of supply does not exist, standards have been set for electricity and gas that these networks have to meet. The electricity network operator TenneT has set a standard for the Netherlands under which the power can be down for no more than four hours in a year, with an indicator that shows how much energy cannot be supplied when demand reaches a certain level per period. For the Netherlands' national gas networks, the operator Gasunie uses the standard of one outage every fifty years. In the Dutch Gas Act, this has been translated to a temperature standard that is essentially a guarantee that gas will always be supplied to small-scale consumers down to a temperature of -17°C (average temperature over 24-hour period minus a correction for wind force). This national standard is the basis for a specific temperature standard ('-13') that regional gas network operators use in the built environment.

Due to increasing electrification, the use of hybrid technologies and the building of heating systems in the built environment, these standards will become increasingly interconnected. Perhaps a new type of standard will have to be formulated for the energy system of the future. This study did not look into this any further.

4.2.6 Weather and climate

Energy supply and demand are dependent on weather conditions. In a year with a lot of wind and sunshine, and therefore with ample energy generation, the energy system is used differently than in a year with a cold period with great demand for heat. The energy system needs to be designed in such a way that it can accommodate a wide range of different weather profiles. This means that a random year with a realistic weather profile must, in the situation as in 2050, not lead to bottlenecks in the system that cause essential users to be faced with shortages. The exact limit will be laid down in a security of supply standard. Since such limits and standards are not yet known for the future, the modelling is based on a year with a representative weather profile.

The bottleneck analyses in the four scenarios for 2050 use the weather profile of the year 2012. The hourly values for temperature, wind speed and sunshine in 2012 were used to compile supply and demand profiles for the 8,760 hours of 2050. The wind and solar profiles for 2012 lead to fairly average power generation volumes compared to years with different weather profiles, but 2012 is also a year with a cold period with high demand for energy.

The year 2012 was chosen from the 1990-2019 range, which is the range that the Royal Netherlands Meteorological Institute (KNMI) uses as the reference period for our current climate (Note: the 'minimum year' 1987 falls outside of this range; that was the year with the most recent occurrence of the national minimum temperature of -17°C at which gas supply is still guaranteed). Chapter 3 includes a number of sensitivity analyses for the weather profiles of years other than 2012 within the current climate period.

In the ETM, the weather profile year 2012 was used to generate supply and demand figures for 2050.
Two adjustments were made during that process:

1. Innovations that increase solar and wind power generation were factored in. The number of full load hours for solar and wind power generation was set higher than the current usual level.

2. Further global warming in the period to 2050 was also taken into account by raising the temperature profile values compared to 2012. See Appendix D.4 for a description of the method.

4.2.7 Interrelationship with carbon and heat supply chains

The Ministry of Economic Affairs and Climate Policy's National Energy System Plan distinguishes four main supply chains: electricity, hydrogen, carbon and heat. The energy system is intertwined with all these supply chains. Since CO_2 and (natural) gas molecules contain carbon atoms, they not only play a role in the energy system, but can also be used in industry to make products, such as plastics, and in horticulture.

The interrelationship with the aforementioned supply chains features in the scenarios, such as in the form of demand for (natural) gas or CO_2 as a feedstock for a carbon-containing product. In order to maintain a clear focus in the analyses, this outlook does not explicitly go into the interrelationship with the other supply chains and, for example, the impact on food and water supply chains and production chains.

Chapter 5

Impact on the national electricity infrastructure in 2050

5.1 Conclusions and recommendations

- All four scenarios have an impact on TenneT's high-voltage grid to varying degrees.
  Further infrastructure expansion on top of the network expansions that TenneT has already planned will be needed for all voltage levels (110 kV to 380 kV) and in all regions.

- International (transit) transmission has a significant impact on the load on the extra-high-voltage grid; international transmission depends on the available transmission capacity of the networks outside the Netherlands and is governed by domestic and EU energy policy.

- The analyses show that the energy transition will bring a significant increase in demand for transmission capacity on the extra-high-voltage grid (EHV, 220/380 kV). There are differences in emphasis between the scenarios.
  In the Decentral Initiatives scenario, 320 km of additional extra-high-voltage lines are needed (20% growth compared to the current number of kilometres), while the European Integration scenario requires the development of 510 km of new connections (33% growth).

- In order to be able to resolve the bottlenecks, the 380 kV corridor from the provinces of Noord-Holland and Zuid-Holland to the south of the Netherlands is projected to require reinforcement with an additional high-voltage line from Beverwijk-Diemen and Maasvlakte to Krimpen, Geertruidenberg and further south from there (Rilland and Eindhoven).
  Several scenarios also project that the connection between Ens and Hengelo will have to be doubled.

- The high-voltage grid (HV; 110/150 kV) will need to expand substantially due to the implementation of the newly required high-voltage substations and the associated connections to accommodate the link to regional network operators. Depending on the extent to which existing HV substations can be expanded with one or two transformers, all scenarios forecast a need for an average of between 50 and 100 new HV substations (15-30% growth) by 2050, compared to the number in 2023.

- In a number of cases, the volumes of electricity produced from renewable sources connected in pockets, such as the Lelystad pocket, are too great. One mitigating measure to take here is to connect production units, preferably clustered, directly to the EHV network. When this is not possible, new HV pockets, with their own EHV connection point, may be needed. This means that a new 380/150 kV or 380/110 kV substation will be needed near the relevant existing EHV connection, which will take up over 20 ha (= 0.2 km ^{2}) of space.

- Flexibility to balance supply and demand generally has a positive effect on transport needs, but it can also have an adverse effect in extreme situations, such as when home batteries increase demand on networks with a lower voltage level in rare cases due to offshore wind power surpluses. Another example is electrolysis at the Maasvlakte industrial park that sometimes uses cheap power from northern Europe. In order to prevent the electricity network from having to be dimensioned to be able to accommodate all these peak situations, the recommendation is to look into further developing the market set-up (allowing local price incentives, amending transport agreements, etc.).

5.2 Network model

A network model is used to map electricity transmission in the network. This model uses the foreseen network topology, including the projects from TenneT's 2022 investment plan.[15][16]

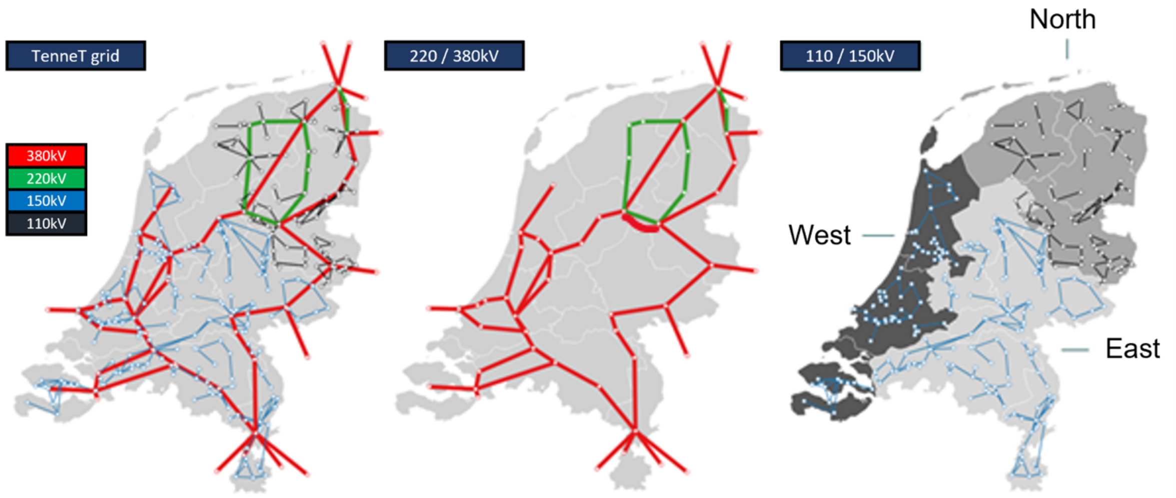

Figure 28: *TenneT network model. From left to right: total grid, extra-high-voltage grid, and high-voltage grid. Note: a 220 kV connection and a 380 kV connection run parallel between Ens and Zwolle; this is not clearly visible in the illustrations.*

5.2.1 Existing network

TenneT transmits electricity over the extra-high-voltage grid (EHV; 220 kV and 380 kV) and the high-voltage grid (HV; 110 kV and 150 kV). The HV network is connected to the networks of the regional network operators by transformers.

The Netherlands' high-voltage grid is made up of a grid with extra-high-voltage (EHV) lines and a grid of high-voltage (HV) lines. The EHV network with voltage levels of 220 kV and 380 kV is used mainly for national and international power transmission. The HV network with voltage levels of 110 kV and 150 kV is used more for regional and provincial power transmission. The power flows over the HV network can go both 'up' to the EHV

[15] Although the period covered by the 2022 IP runs through to 2030, not all projects from the 2022 IP will actually be completed by 2030. That being said, they have all been included in the network model used.

[16] The 2022 IP also includes projects that are still in the early study phase and on which a final investment decision has yet to be made. These, too, have been included in the network model used.

network (in case of a regional surplus due to, for example, a peak in solar power production) or come 'down' from the EHV network (in case of a regional shortage).

The EHV network has a central 380 kV ring and smaller ring structures that connect Borssele, the Maasvlakte industrial park, Beverwijk and Eemshaven to the central ring. The HV network has traditionally always been more provincially oriented. The high-voltage connections are interconnected in the provinces and linked to the EHV network at various points.

5.2.1 Model of the expansions

A large number of EHV network expansions will be completed by the year 2035. The investment decision for these expansions has already been made or is being prepared. In conducting the analyses for the second edition of II3050, all these projects were included in the model, so as to identify bottlenecks that will arise between 2035 and 2050.

In the HV network, introduction of the pocket structure is the main change that has been incorporated into the network model. Due to large-scale transport over the EHV network, the HV network's finely meshed network structure that has grown over the years is no longer tenable. There are unwanted parallel transports that lead to extensive excess loads in the HV networks. By splitting up the HV networks in the provinces into several sub-networks, or pockets, that are no longer interconnected, major power flows are routed over the EHV network, thus preventing excess loads in the HV network. This is comparable to how long-distance through traffic uses motorways instead of secondary roads. For this study, a total of 49 pockets were incorporated into the model.

5.2.2 International model

Supplementary to II3050-1, this second edition has not only worked out the implications for the Dutch high-voltage grid, but also included a representation of the grid in the countries around the Netherlands (Germany, Belgium, France and Luxembourg) - including planned future expansions based on the Ten Year Network Development Plan (TYNDP). This was added to the outlook because electricity transmission in other countries also has a major effect on transmission in the Netherlands. It also brings the network impact analysis of II3050-2 closer to TenneT's investment plan, which includes the same countries in its analysis.

5.3 Methodology

In order to establish the severity of the capacity bottlenecks in the EHV and HV networks, the outlook uses a year-round calculation method. The volumes of power generation and demand for every hour of the year, as extrapolated from the market analysis, are allocated to physical locations in the network, i.e. regionalised, based on fixed rules, following which the resulting power flows can be identified. Whenever this exceeds the maximum permitted load[17] of circuits or transformers, this is considered a bottleneck. A singular outage of another circuit, transformer or production unit is then anticipated.

The severity of the bottleneck is quantified using an 'energy not transported' indicator (ENT); see Figure 29. This indicator has been determined for each relevant network element (circuit or transformer), and has been defined as the sum of all 'overloads' (power flow less the element's maximum permitted load) for all hours during which the maximum is exceeded. As a result, this indicator shows for each connection how much of the annual amount of energy in TWh cannot be transported safely. In addition, TenneT tracks a number of other indicators to

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[17] We use different permitted loads for the summer period (April to October) and the winter period (November to March).

assess the severity of a bottleneck, such as the number of hours when the maximum is exceeded and the maximum overload in the year.

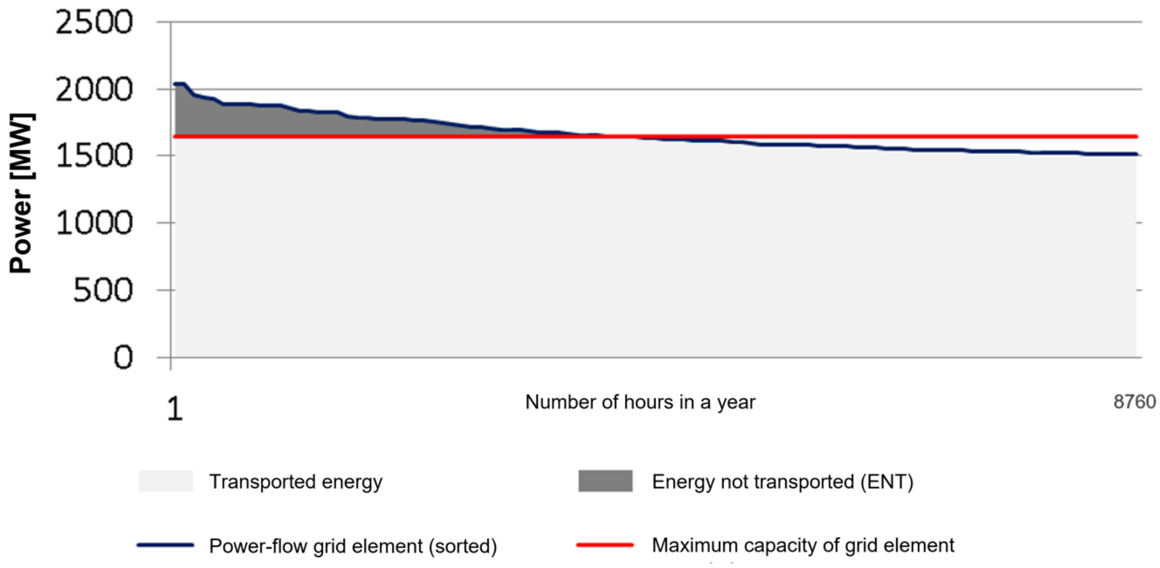

Figure 29: *Visualisation of the calculation of the amount of energy not transported.*

5.4 Results

5.4.1 220/380 kV infrastructure analyses

- The year-round calculations show the bottlenecks on the 220/380 kV grid for each scenario of II3050-2; see figure 30. The yellow connections are connections where network reinforcement will be required.
  The markings in the network maps show that all the scenarios will have a major impact on the EHV network. While there are certainly differences between the four scenarios, they still show a reasonably uniform picture. In order to be able to resolve the bottlenecks, the 380 kV corridor from the provinces of Noord-Holland and Zuid-Holland to the south of the Netherlands is projected to require reinforcement with an additional high-voltage line. This will run from Beverwijk/Diemen and the Maasvlakte industrial park to Krimpen, Geertruidenberg and further south (Rilland and Eindhoven). Several scenarios also project that the connection between Ens and Hengelo will have to be doubled. There are differences in emphasis between the scenarios. In the Decentral Initiatives scenario, 320 km of additional extra-high-voltage lines are needed (20% growth compared to the current number of kilometres), while the European Integration scenario requires the development of 510 km of new connections (33% growth).

Decentral Initiatives

National leadership

European integration

International trade

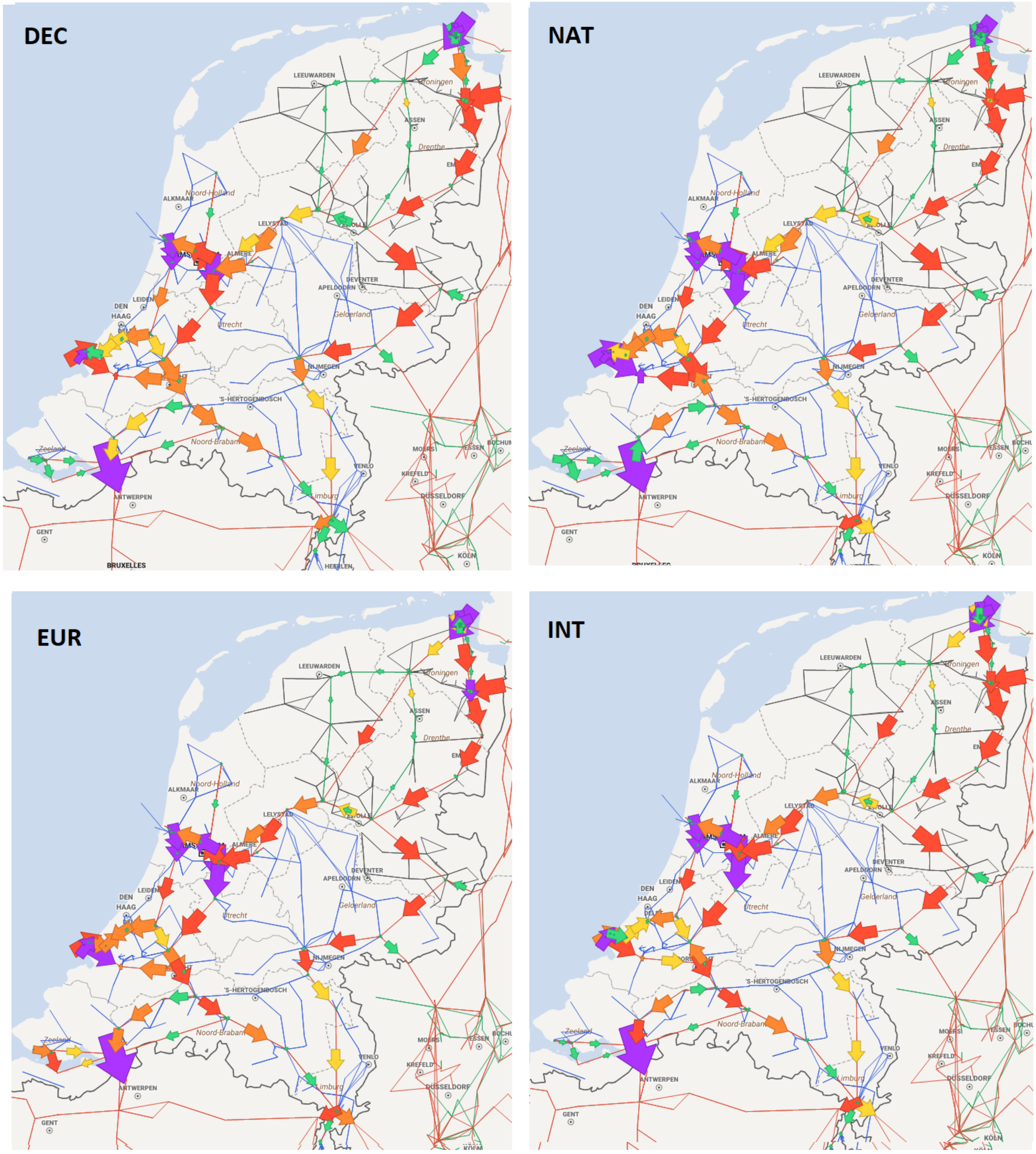

Figure 30: *Bottlenecks in the EHV network for the four scenarios for 2050. The colour of the arrows indicates the ENT (energy not transported), classified into five categories, ranging from green (no bottleneck) to purple (very severe bottleneck). The size and direction of the arrows indicate the maximum permitted load for an hour in the year.*

5.4.1.1 International transport through the Netherlands

The analyses show that the energy transition will bring a sharp rise in demand for transmission capacity on the extra-high-voltage grid (EHV; 220/380 kV). However, given the dominant impact of international power transmission or transit on the load on the EHV network, many of the necessary additional investments in the EHV network depend to a large degree on the result of talks with European partners on providing international transport. Since this international transport depends on the available transport capacity of networks abroad on the one hand, and is affected by domestic and European energy policy on the other, the expectation is that the bottlenecks on connections along the Netherlands' eastern border, between substations with interconnectors, will occur to a much smaller degree in reality. This has been taken into consideration in formulating the required measures.

The results show that there is a lot of transport along the cross-border connections, the Meeden-Diele and Eemshaven-Emden interconnectors (between the north east of the Netherlands and Germany) and the Rilland-Zandvliet interconnector (between the south west of the Netherlands and Belgium). This transmission is largely made up of transit flows, such as from northern Germany to Belgium and France over the Dutch grid, and what are known as 'loop flows'[18] from the north to the south of Germany through the Netherlands.

The expectation is certainly that this kind of international electricity transmission will increase. However, these flows are overestimated in this analysis, because the market analysis assumed a fixed transfer capacity between two countries (net transfer capacity (NTC)). In reality, however, this transfer capacity is determined during the operation based on the available space on the high-voltage grid (flow-based) at that moment, causing there to be less transport at those times. The transport needs on the Dutch high-voltage grid (especially in the north → south direction along the eastern border) are also less sizeable than the analysis suggests.

However, the bottlenecks identified on the above-mentioned interconnectors clearly show that there is a major need for transport on a European scale at these locations. Adding interconnectors will not instantly clear these bottlenecks, due to the fact that additional transfer capacity leads to more transport, as long as the underlying demand for transport is not fully satisfied. Other ways to control the interconnector bottlenecks are:
- scaling up phase angle regulators (PARs);
- using (offshore) DC infrastructure for greater control of the flow direction;
- better spread of large-scale generation (such as through landfall of offshore power further inland in the south-eastern Netherlands or southern Germany);
- further development of European market regulation (such as splitting up bidding zones).

However, in order to be able to make the most of the current interconnection capacity, the connection between Ens and Hengelo will have to be reinforced to create a strong connection on the northern side of the national 380 kV ring.

5.4.1.2 Domestic transport

The biggest bottlenecks in the 220/380 kV network seem to arise around the 380 kV substations in Diemen and Beverwijk and on the connection to the south. This is caused by, on the one hand, large-scale offshore wind power landfall in the northernmost part of Noord-Holland province. The power is transported along four circuits from the Middenmeer 380 kV substation to the connection between the 380 kV substations in Diemen and Oostzaan. On the other hand, there is high-volume transmission from the northern Netherlands to Diemen over four circuits, both due to the international transport described above and during periods of major demand for flexibility at the Maasvlakte industrial park that cannot be met using offshore wind power. The envisaged network between Diemen, Beverwijk and Zuid-Holland province seems not strong enough to be able to transport this power onwards to meet demand in the south. Given the decision to have a large-scale offshore wind power landfall point in the northernmost part of Noord-Holland province, the network in this area will probably have to be reinforced.

The bottlenecks in the Maasvlakte ring differ slightly from one scenario to another. The Decentral Initiatives and International Trade scenarios show less severe bottlenecks than the National Leadership and European

[18] Transport from production to demand in the same country but that passes through other countries.

Integration scenarios. This seems to mainly be caused by differences between the scenarios with respect to offshore wind power landfall and industrial demand in the Maasvlakte ring. The connection between Maasvlakte and Simonshaven seems to be a severe bottleneck in all scenarios. Besides expanding transport capacity, further research will be needed into how to adequately match supply and demand on a local level in Rotterdam's port area.

The connections in Zeeland province only get excess loads in the European Integration scenario. This can be put down to the major capacity that the nuclear plants in Borssele are assumed to have (around 5 GW), in combination with large-scale offshore wind power landfall in Zeeland province. It is important, therefore, to take an overall look at the developments in nuclear power and offshore wind power in Zeeland province.

The need for transport from the western Netherlands to the east through Noord-Brabant province appears to be less than in previous studies. First of all, II3050-2 assumes two additional circuits between Eindhoven and Maasbracht, which resolves this previously identified bottleneck. In addition, large volumes of offshore wind power, and in some of the scenarios nuclear power as well, from Zeeland province and Zuid-Holland province will cross the border at the Rilland 380 kV substation, in the east of Zeeland province, to the Zandvliet 380 kV substation in Belgium. This is in part due to the fact that Belgium has relatively limited offshore wind power production potential, which is why offshore wind power surpluses are mostly transported to Belgium. Additionally, the aim from the German investment plan (NEP) to route part of the offshore wind power that Germany produces directly to a point near the Ruhr area has been taken into account, which is why there is also less transport of Dutch offshore wind power to Germany via the 380 kV substation at Maasbracht (Limburg). That said, moderate to severe bottlenecks have still been identified in Noord-Brabant province, meaning that additional infrastructure may be required.

After analysis of all the results, the conclusion is that the Decentral Initiatives scenario will require approximately 320 km of additional high-voltage lines (20% growth compared to the current number of kilometres), and that the European Integration scenario will require development of around 510 km of new connections (33% growth). This growth in transport capacity is expected to enable accommodation of all the required transport as efficiently as possible.

The above conclusion is in line with the findings from TenneT's analyses for the Target Grid. The next step in further defining the Target Grid will assess in greater depth whether and how integrating the projected HVDC offshore network and a DC onshore network can help reduce or phase the investments in the national AC network.

5.4.2 110/150 kV infrastructure analyses

The year-round calculations show the bottlenecks in the 110/150 kV grid for each scenario of II3050-2; see figure 31. The markings in the network maps show that all the scenarios will have a major impact on the HV network. While there are certainly differences between the four scenarios, they still show a reasonably uniform picture here too.

There are bottlenecks in the 110/150 kV connections in several pockets (sub-networks) and in the transformers that make up the connections between the EHV network and the HV network. Broadly speaking, a number of bottlenecks in the pockets and the transformer substations are caused by excessive demand, excessive generation or excessive flexible power that ends up at the 110/150 kV substations in the pocket in question following the regional breakdown (regionalisation). One example of this is the large-scale power generation from renewable sources that is allocated to the Lelystad pocket in the regionalisation process.

The solution to these bottlenecks is to directly connect major (industrial) load demand, generation and flexible power to a nearby 380 kV substation, i.e. not in the 110/150 kV pockets. If this is not possible, splitting the pocket in question up into two or more pockets is an option to be considered. A new 380 kV substation would be needed for each new pocket.

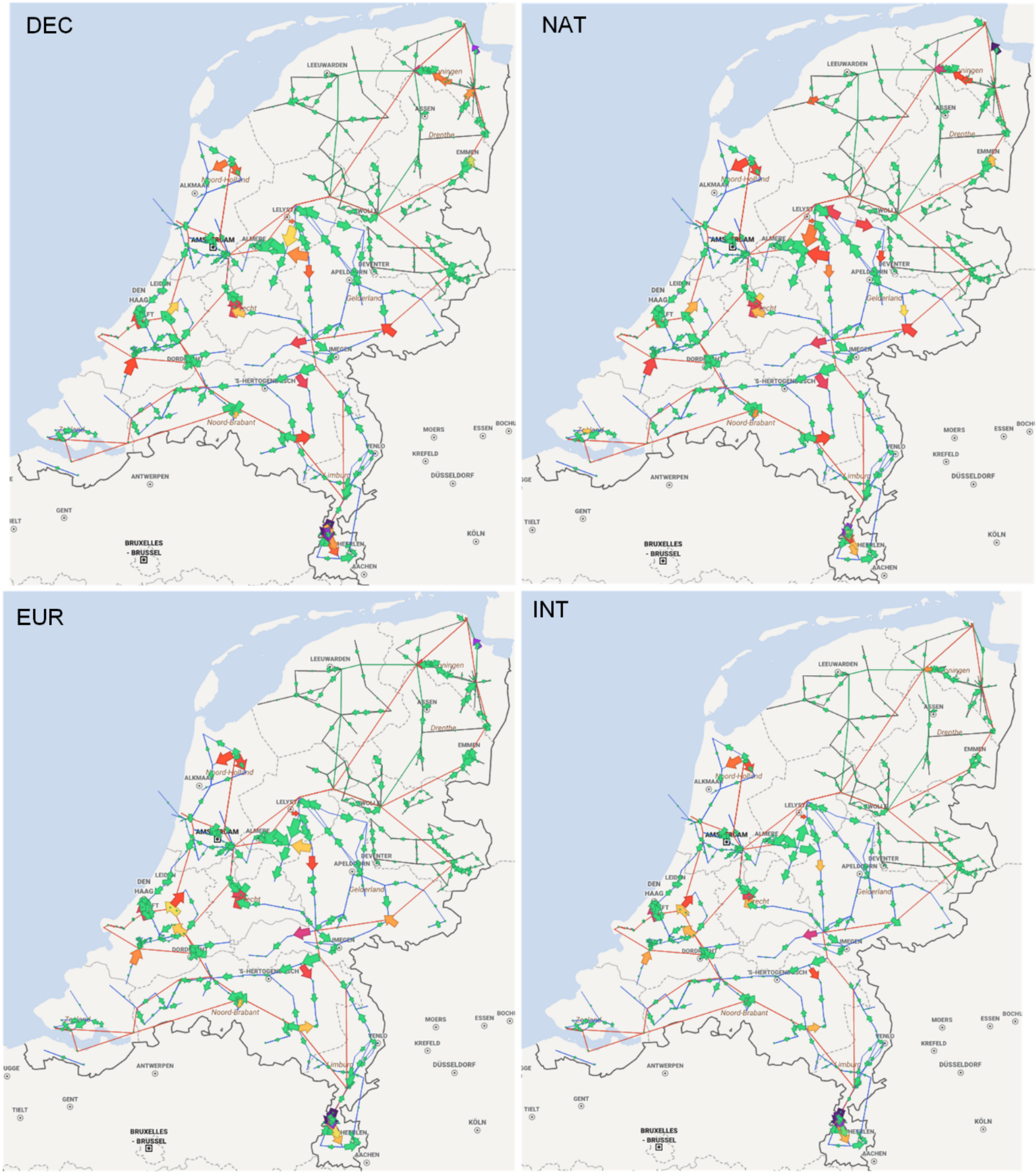

Figure 31: *Bottlenecks in the HV network for the four scenarios for 2050. The colour of the arrows indicates the ENT (energy not transported), classified into five categories, ranging from green (no bottleneck) to purple (very severe bottleneck). The size and direction of the arrows indicate the maximum permitted load for an hour in the year.*

A total of 327 HV substations have been modelled in the 49 pockets, with connections to the regional network operators and customers connected directly to the HV network. There are differences in emphasis visible in the four scenarios. Depending on the extent to which existing HV substations can be expanded with one or two transformers, the scenarios forecast a need for an average of between 50 (15% growth) and 100 (30% growth) new HV substations by 2050, on top of the existing stations in 2023.

5.5 Infrastructure developments for 2050

The network model calculations in the four scenarios for the end year of 2050 show that the national electricity grid as it is projected to be after 2030 (see Section 6.2) will not be able to accommodate the required electricity transmission. As a result, further expansion of the infrastructure between 2030 and 2050 appears to be necessary.
In defining the development pathways for the national electricity grid, a distinction is also made between the 220/380 kV network and the 110/150 kV network.

5.5.1 220/380 kV network developments

For the 220/380 kV network, it is first and foremost key that projects from the Investment Plan are implemented. Projects from the 2022 IP have already been incorporated into the model as a starting point, including projects that are still in the study phase. The analyses in II3050-2 confirm the benefit and necessity of these investments. After that, there also seems to be a need for additional transport capacity around Diemen, Beverwijk and the Maasvlakte industrial park, as well as between Maasvlakte and Eindhoven. Needless to say, this depends on domestic and international developments in network design, market design, demand, power generation and flexibility, and the connection locations for offshore wind power. Reinforcement of the connection between Ens and Hengelo will help create a strong corridor from the Randstad area in the west to Germany in the east along the top end of the national 380 kV ring.

As explained in Section 6.4, not every single bottleneck identified in this study means that new infrastructure will be needed at that location:

- The possible need to expand the network in Zeeland province, for example, depends greatly on whether or not additional nuclear energy in Borssele is combined with large-scale offshore wind power landfall. If other choices are made here, additional infrastructure may not be necessary.

- The need to extend the 380 kV ring to Maasvlakte also depends on what scenario you look at, especially on assumptions about offshore wind power landfall and electrification of industry.

- The severe bottlenecks in the interconnectors with Germany and Belgium will have to be analysed on a European level. Changes to the way the European market is organised and international coordination of network investments could have a major impact on these extensive international transmissions.

Finally, adding new transport capacity at the 380 kV level takes a lot of time. Experience shows it might take between 10 and 15 years. This means that investment decisions have to be made now for infrastructure that will only become available in the second half of the 2030-2050 period. As a result, there are still considerable uncertainties around these decisions and they may need to be changed in the long term. Even so, it is necessary to start the preparations.

5.5.2 Impact of offshore network growth

The Dutch government has launched an ambitious programme to generate more offshore wind power.
Up to 2031, the aim is to connect 21 GW in offshore wind power to the 380 kV network, but that is not all. Depending on the scenario considered, offshore power transmission capacity will grow further by 16 to 31 GW over the period between 2030 and 2050. TenneT is developing a standard platform concept for that, which will be connected to the 380 kV network through a 2 GW DC connection. Therefore, 8 to 16 of these connections in total are still needed. In order to be able to maintain system stability, a maximum of three 2 GW connections can be connected to one 380 kV substation, which has two consequences:

- The direct current has to be converted into alternating current by a converter station. Depending on the scenario, another 8 to 16 new converter stations will have to be built at several locations across the Netherlands. These converter stations should preferably be built near the relevant 380 kV substation.

- Additional connection bays at the 380 kV substations will also be needed: two bays per 2 GW connection. To accommodate these bays, substations will have to be expanded or perhaps new 380 kV substations will have to be built.

5.5.3 110/150 kV network developments

For the 110/150 kV network, further implementing a pocket structure is a key first step. Based on load, power generation and flexibility developments, new pockets or 110/150 kV connections may be needed in some cases. Connecting new pockets to the 220/380 kV network will in some cases also require new 220/380 kV connections. In addition, it is important to connect large-scale initiatives (load, power generation or flexibility) directly to the 220/380 kV network, so that they will not place a load on the 110/150 kV network.

Chapter 6

Impact on national methane and hydrogen infrastructure up to 2050

6.1 Conclusions

Methane

- Despite falling demand and supply, a main transport network with nationwide coverage for natural gas, and later for green gas, will continue to be needed at least until 2050.
  - In order to be able to absorb imbalance in the remaining natural gas demand and supply, suppliers and consumers will have to be connected to gas storage facilities. The methane network will have reduced capacity but will continue to fulfil this role, with connections between industrial clusters and storage facilities, and possibly also areas in the built environment where there is still demand for gas. In the scenarios that foresee a role for natural gas or green gas in providing heating in the built environment, gas infrastructure connected to those parts of the built environment will also continue to be needed.
  - Methane transport volumes in 2050 will be much smaller than today's volumes. This means that far fewer pipelines and fewer compressors for gas will be needed than at present. On network sections with multiple parallel pipelines, only one or two of these pipelines will still be needed for methane transport. Pipelines can be repurposed for hydrogen transport or, for example, as collector and/or transport pipelines for green gas.
  - The remaining methane transport will not require any network upgrades.
  - Based on the pipelines available in 2040 and 2050, it is possible to maintain the two main gas quality categories, i.e. high-calorific and low-calorific gas, alongside each other. However, situations may arise where ratios of these two gas qualities are not balanced, creating a need for quality conversion, either from high-calorific to low-calorific or vice versa. Blending plants will have to be built for that.
  - The increasing volumes of green gas that will have to be fed in will also necessitate a rearrangement of the national methane network. Locally produced green gas can be fed into the high-pressure transport network via boosters. The number of boosters needed can be limited by using onward connections in the RDN and repurposing pipelines as green gas collector and/or transport pipelines. Measures in relation to gas composition will have to be made for the benefit of users and for storage purposes (such as permitted oxygen content or adding odorant).

Hydrogen

- Each of the four scenarios projects that the hydrogen network that is currently being prepared as per the roll-out plan will require further expansion through to 2050. This can be done in an adaptive way because most of the measures will be needed in all scenarios.
  - Most of the hydrogen network can be expanded along the current sections of the natural gas grid. The outlook did not look into creating new sections. More transport capacity is needed in all scenarios, especially parallel pipelines along the sections of the national hydrogen network.

- New hydrogen pipelines are needed on some sections of the network, mainly to enable additional transport from west to east along routes crossing Noord-Brabant province and the Betuwe region. The International Trade scenario has the largest hydrogen transport capacity, with the largest number of new sections from west to east, due to the transit flows to Germany.
  - New connection pipelines will also be needed on the branch sections to industrial areas, power plants and storage facilities.
  - Hydrogen compression will be required at multiple locations on the main hydrogen network. Compression will often be required in multiple directions, which will necessitate extensive network switching capabilities.
  - Hydrogen compression can generally be built in at existing natural gas compression sites. After 2030, hydrogen compression is also expected to be needed at some new sites.
  - Variations on the base scenarios show an additional challenge. Additional hydrogen flows through the Netherlands to Belgium (approx. 4 TWh) and Germany (approx. 150 TWh), on top of the National Leadership scenario, can be accommodated through an upgrade of the pipeline to Belgium through Zeeland province - the base scenarios already use this route to the maximum degree - and an additional compression site, while the route to Germany still has considerable transport room available in the base scenarios. In order to be able to cope with years with more severe weather profiles, approximately 90-150 km of pipeline will have to be upgraded, i.e. built new, and additional compression will be needed.
  - To bring hydrogen produced offshore with electrolysis to the shore, an offshore hydrogen network that connects to the onshore network will be needed from 2030.

- While repurposing parts of the regional gas transport network for hydrogen is possible, it will involve a customised approach for each situation, in collaboration with regional network operators. Repurposing gas networks for hydrogen and the resulting allocation conundrum will require a great deal of coordination (see also Chapter 8).

Storage

- Large-scale storage in molecule form will be needed to balance the energy system of the future. The operational storage capacity needed for green gas totals between 1 and 12 TWh, while that needed for hydrogen is between 14 and 29 TWh in 2050, based on a year with an average weather profile. Based on the exploratory calculations for all weather profiles, a maximum storage capacity of 30 TWh will be needed for green gas in 2050. For hydrogen, the storage need will increase to a maximum of 60 TWh by 2050. Operational storage is intended both to bridge the seasons and for short-cyclical storage. When primarily using existing gas storage facilities for seasonal green gas storage, and if empty gas fields can also be used for seasonal hydrogen storage (an option which is still being studied), a maximum of 70 caverns will be needed for green gas and hydrogen combined in 2040, and 15 in 2030. Certain forms of flexibility, such as cracking plants that convert ammonia into hydrogen, can bring these numbers down further.
  - Additional strategic storage will be needed for consecutive years with low temperatures or a lack of power generated from solar and wind energy, but also to cover a drop in imports due to geopolitical developments. To cope with four consecutive years with adverse conditions, between 35 and 59 TWh of

strategic storage capacity will be needed, depending on the scenario. It may in the long term also be possible to use existing gas storage facilities combined with a unit that converts methane into (blue) hydrogen as strategic storage. This requires further research. Natural gas storage facilities will continue to be used for a long time and the first caverns for hydrogen will be needed around 2030. The required storage volumes will increase rapidly after that, and so preparations have to be initiated now.

6.2 Network infrastructure

The bottleneck analysis assumes the onshore gas network that will be in place in 2035, i.e. including the network developments envisaged for the period up to 2035, such as the onshore hydrogen network. This starting point was chosen based on the 2024 IP, in combination with the roll-out plan[19] for the hydrogen network as published on 29 June 2022, including the amendments announced by the Minister for Economic Affairs and Climate Policy on 2 December 2022.

6.2.1 Current network infrastructure: HPGG and RDN

Gasunie’s current national methane gas transport network consists of two parts: a high-pressure gas grid (HPGG) and a medium-pressure transport network (regional distribution network, RDN). In total, these networks comprise over 12,000 km in pipelines, of which half in the HPGG and the other half in the RDN.

The focus in this outlook is on the HPGG. That is where the biggest gas flows are and it is the most dynamic part of the gas transport system. The major import and export flows, industrial demand, the alternating filling of and withdrawal from storage facilities, and the blending of different gas qualities all converge in the HPGG. The HPGG is made up of:

- long pipelines with large diameters of up to 48 inches;
- compressors to increase the pressure;
- blending stations to blend nitrogen into high-calorific gas to make low-calorific gas;
- metering and regulating stations to reduce the pressure to approximately 43.5 bar for the RDN, and to add the typical gas odour.

The RDN is of an entirely different nature. It transmits smaller gas flows over average distances of generally a few kilometres from the HPGG to grid users. The RDN pipelines have smaller diameters, typically between 4 and 20 inches, while compressors are not needed given the small transmission distances.

The HPGG is split up into two sub-networks, one for transmission of high-calorific gas (H-gas) and one for low-calorific gas (G-gas). High-calorific gas can be converted into low-calorific gas at several points in the system by blending high-calorific and low-calorific gas or by adding nitrogen to high-calorific gas. Depending on the conditions (summer/winter, day/night) and the combination of supply and demand, varying quality categories of gas flow through the system at the same time.

The current network is detailed in Appendix E1.

19 https://www.hynetwork.nl/over-hynetwork-services/uitrolplan

6.2.2 Network developments up to 2035

Gasunie is in the process of preparing a national hydrogen transport network, which will be operational by 2030. This transport network will develop in step with the development of hydrogen supply and demand in the market: from connections with and between major industrial clusters, to national connections and on to hydrogen storage facilities in the north of the country. In line with the roll-out plan, this hydrogen transport network and these hydrogen storage facilities will become available in phases over the 2023-2030 period.

A hydrogen transport network with nationwide coverage will largely (approx. 70%) consist of repurposed existing pipelines, while about 30% will have to be built in the form of new hydrogen transport pipelines. By 2030, the connecting network will measure over 1,100 km, also provide international transport to Germany (to the Ruhr area and Hamburg) and Belgium (Antwerp), and can be connected to large-scale production and offshore hydrogen pipelines far out in the North Sea. See Figure 32 for the overall configuration.

At this point in time, it is not clear exactly how many or what kinds of connection pipelines will be needed to connect smaller industries (‘cluster 6’) and other sectors to the hydrogen transport network. The roll-out plan for hydrogen to the regions has yet to be made. The Ministry of Economic Affairs and Climate Policy’s HyRegions programme has been set up for this purpose. Gasunie and the regional network operators are participating in this programme through Netbeheer Nederland.

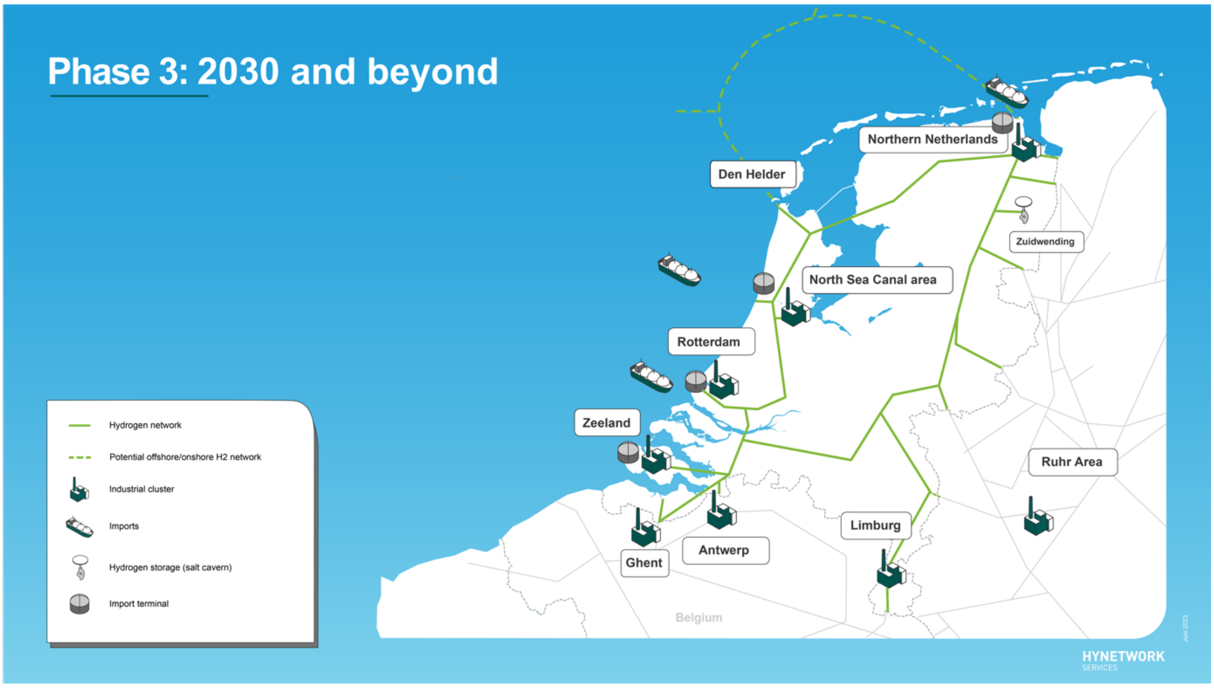

Figure 32: *Outline of the hydrogen network around 2030 (in accordance with the roll-out plan)*

As the design of the national hydrogen transport network currently stands, it will provide 10-15 GW of transport capacity in 2030. This figure will rise further beyond 2030. See Appendix E2 for a more detailed description of the anticipated network developments up to 2035.

It will become increasingly important to weigh up the options in planning the capacity for the gas transport network. This is mainly the case during the transition phase, when it will have to be decided at what point a ‘classic natural gas pipeline’ can be repurposed for a different type of gas. Since demand for natural gas will drop and the volumes of green gas will remain limited, the required transport capacity will decrease and the hydrogen transport network can be developed through to 2030 without bottlenecks for (natural) gas, and further expanded, as needed, over the period through to 2050.

6.3 Bottlenecks and solution approaches for methane and hydrogen pipelines for 2050

6.3.1 High-pressure gas grid – HPGG

In view of the expected developments for hydrogen, the bottleneck analysis for the HPGG is twofold: one for the (natural) gas network and one for the hydrogen network. An important starting point is that both networks can make maximum use of existing gas transport pipelines. A 2017 study by DNV GL[20] shows that virtually all pipelines that make up the national gas transport network can be repurposed for hydrogen transport.

The method used to identify capacity consequences for the networks is described in Appendix E3.

A bottleneck occurs when pressure and quality requirements cannot be met in a transport situation. Calculations show that bottlenecks occur in all four scenarios and in both networks, based on the networks as they are expected to be in 2035. Depending on the scenario, a predefined solution strategy is used to work out what size the network needs to be to be able to accommodate the transport scenarios.

Often, there are several possible solution approaches that lead to a suitable network design. Laying additional pipelines is, for example, to some extent interchangeable with using compression to create a suitable network. The measures chosen are, therefore, possible configurations of the networks in 2050. This study is of an exploratory nature and the level of detail of the calculations and solutions identified are in line with that. The emphasis is on potential bottlenecks on the main routes.

The first step in the solution strategy to resolve bottlenecks in the hydrogen network is to repurpose (natural) gas pipelines that are still in use in 2035. However, this is on the condition that such repurposing does not lead to new bottlenecks in the methane network. Many sections of Gasunie’s network have multiple pipelines side by side. Switching pipelines is often possible with relatively little outlay, for example requiring only an additional connection and cleaning. Given the fact that the scenarios set out the 'four corners of the playing field', different measures will be needed in the various scenarios. While all the scenarios depart from the same starting point, they have different end points.

For locations where reuse of pipelines does not fully resolve bottlenecks, other solution approaches have been defined. For hydrogen, these are the following solution approaches: use of compression and laying new, parallel pipelines. New pipelines are laid alongside existing ones because these are often sections defined in the Dutch government’s structure vision on pipelines [*Structuurvisie Buisleidingen*], meaning that there is space available for the pipelines.

The solution approaches chosen to resolve bottlenecks will ultimately lead to a hydrogen network that will roughly look the same as the existing HPGG. After all, existing (natural) gas pipelines will be reused or new pipelines will be laid in parallel to existing ones.

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20 ‘Verkenning waterstofinfrastructuur’ [Hydrogen infrastructure outlook], DNV GL report OGNL.151886, Rev. 2, November 2017

6.3.1.1 Hydrogen network results

Figure 33 shows the hydrogen supply capacities in the various scenarios. The capacity is greatest in the International Trade scenario, and smallest in the European Integration scenario. Transport capacities from/to storage facilities are relatively large (see Figure 33).

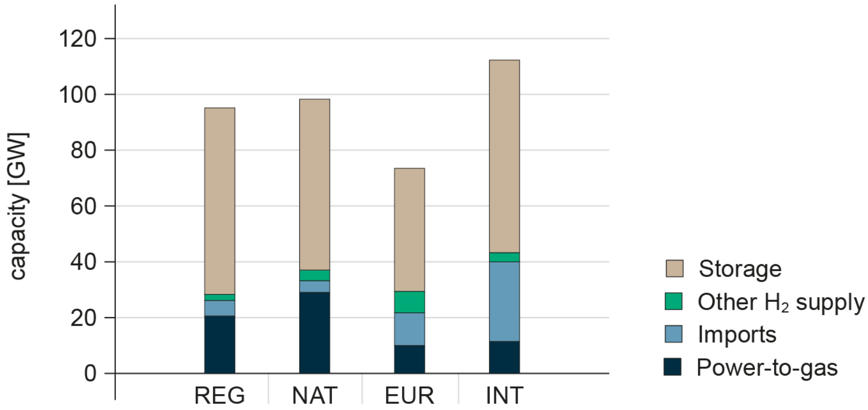
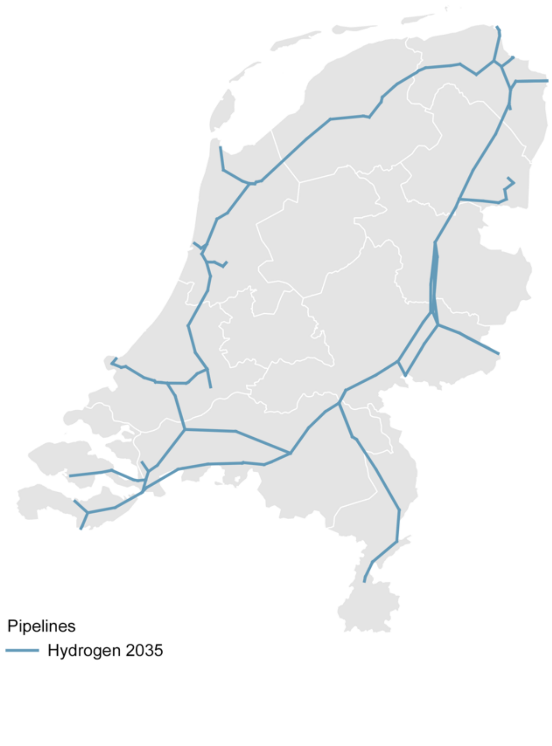


Figure 33: *Hydrogen supply capacity in the four II3050-2 scenarios, in 2050*

Figure 34 shows the starting network for hydrogen, with the main routes.
This is the target network in 2035.



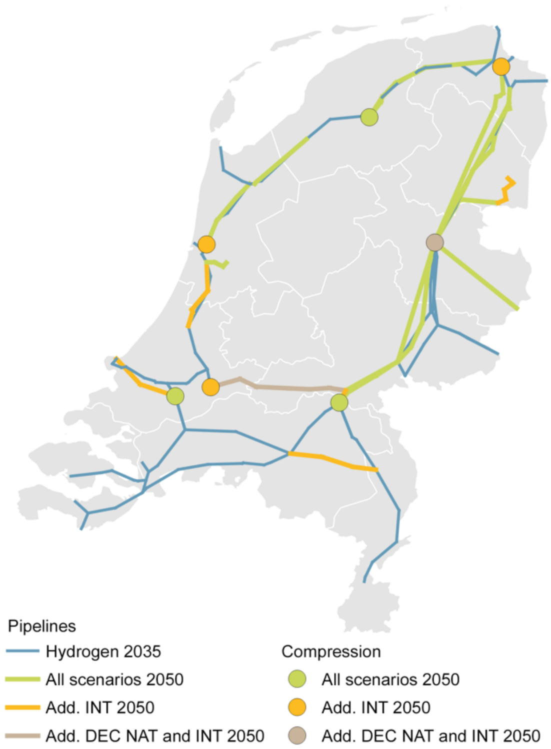


Figure 34: *Hydrogen network in 2035*

Figure 35: *Hydrogen network in 2050*

Figure 35 shows what the main routes of the hydrogen network could look like in 2050. The light-green sections are the ones that have to be upgraded in all scenarios. Many sections will have to be upgraded in all scenarios, especially in the eastern part of the Netherlands and an additional east-west link through Lake IJsselmeer.
The European Integration scenario requires the least upgrades to the hydrogen network. The section that crosses the Betuwe region is not necessary in this scenario, while it is in the other scenarios (shown in brown).
The International Trade scenario requires the most upgrades in the hydrogen network. The yellow sections are the ones that will only be needed in this scenario. When light-green, brow, or yellow sections are shown next to sections that are already there in the starting network of 2035, this means that the capacity in these sections will have to be increased.

Figure 35 shows dots at various locations. These dots denote locations where compression will be required.
The light-green locations are needed in all the scenarios, the brown location is needed in all but one scenario (not in the European Integration scenario), and compression will only be needed at the yellow locations in the International Trade scenario.

6.3.1.2 Transition pathway from 2040 to 2050

Figure 36 goes into more detail for the International Trade scenario, showing which sections are made up of converted pipelines and which ones are made up of new pipelines. This is because this scenario will require the most extensive hydrogen network – the other scenarios fall within that network. The dotted lines are sections that have to be built from scratch, while the solid lines represent methane pipelines that will be repurposed.

The figure also charts the development pathway: which sections need to be upgraded by 2040 and which ones will have to be upgraded further after that by 2050. The green lines are needed by 2040, the yellow ones by 2050.

In each scenario, roughly 750 km of pipeline will have to be converted. There is very little variation between the scenarios, due to the limited variation in the amount of transport capacity needed. On top of that, pipelines for conversion often have a large diameter, meaning that they will be overdimensioned in most scenarios. In the International Trade scenario, an additional conversion of approx. 50 km is needed. Of the total 750 km of pipeline conversions, roughly 200 km will have to be done by 2040. In the European Integration scenario, this is 130 km.

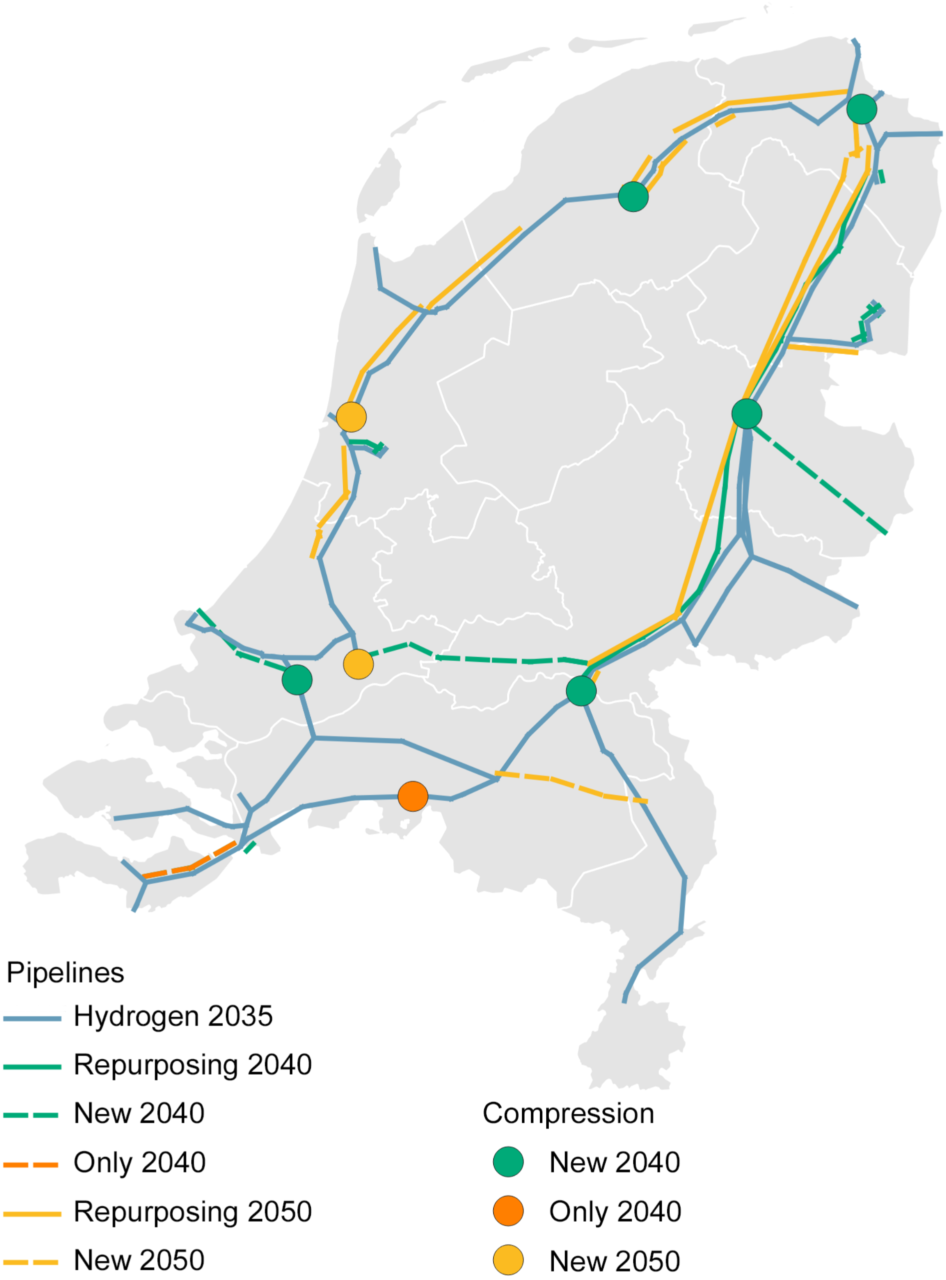


Figure 36: *Development pathway for the International Trade scenario*

Most of the conversions along the north-south route are needed in the eastern part of the Netherlands. This is also the section of the network where the most pipelines are available, because of the former gas transport from the Groningen gas field to the south. Most of the salt formations, and with that the biggest potential for hydrogen storage, are located in the eastern part of the Netherlands. As a result, it will have to be possible to transport large volumes to and from the east. If storage facilities are eventually created elsewhere in the Netherlands, the potential impact on the network will have to be reassessed.

In each scenario, new hydrogen pipelines will also be needed in the main network on top of the repurposed existing natural gas pipelines. Depending on the scenario, this concerns a maximum of 250 km in new pipelines.

It is not possible to draw a general conclusion about the required number of kilometres for branches from the main network. Seeing as the hydrogen network has not been built yet, districts are notionally connected to the hydrogen network over the shortest distance in the calculations (see Appendix E3). This means that the calculations do not provide any insight into what connection pipelines are actually needed. Only the required upgrades on the sections expected in 2035 are assessed in this way.

Besides pipelines, compression is also needed in the hydrogen network. Using the same colours as for the sections that are to be upgraded, Figure 36 shows for the International Trade development pathway where compression will be needed in 2040 (green dots) and where additional compression will be needed in 2050 (yellow dots). At one location, in Noord-Brabant province, compression will be needed in 2040 in the scenarios, but not any more in 2050 (orange dot). This is related to the assumption that there will be more export to Belgium in 2040.

At most of the locations, compression will have to be available in multiple directions, meaning that a great many switching capabilities will have to be created when building compressor stations.

6.3.1.2 Offshore hydrogen network

In the future, part of the hydrogen will be produced out at sea. In the National Leadership scenario, 20 GW of electricity will be produced at sea and converted into hydrogen on rigs or islands in 2050. The 14 GW of hydrogen produced using electrolysis will have to be brought to the shore through pipelines. Besides the hydrogen from dedicated electrolysis, hydrogen will also be produced from hybrid connected wind farms, i.e. whereby both electricity and hydrogen are brought to the shore. How much electricity and how much hydrogen that will be exactly is still being studied. More about this can be found in Section 10.4.

To take the hydrogen to the shore, an offshore hydrogen network will be needed that connects to the hydrogen network on land. This is not only the case in the National Leadership scenario, but also in the other scenarios. The amount of hydrogen produced in those other scenarios is, however, smaller, with around 6 GW from dedicated electrolysis, possibly plus hydrogen from hybrid connected hubs in the Decentral Initiatives and International Trade scenarios. In the European Integration scenario, there is only the possible hydrogen production from hybrid connected hubs, which will require a network just the same.

In principle, landfall could be done ‘radially’, just like with electricity cables, i.e. with a dedicated pipeline from each electrolysis hub to the coast, but this is not efficient. The transport capacity of a 36-inch pipeline, which is a fairly common size for offshore pipelines, is already around 15 GW, depending on what pressure regime is chosen. A possible efficient configuration would be a pipeline ring that runs past all major electrolysis hubs and reaches the shore at two locations on the coast. Such a pipeline can take the capacity of various production sites to the shore. The capacity can be further increased by installing compression facilities or laying a second, parallel pipeline.

Two landfall points would increase transport security. Obvious choices for landfall points are Eemshaven and Den Helder. That is where natural gas pipelines reach the shore and where there is expected to be space for a hydrogen pipeline, while also offering good connections to the onshore network. Possible reuse of part of the existing offshore natural gas pipelines is still being studied.

The development of offshore hydrogen production will start around 2030 with two pilots, with a total scope of 600 MW. Figure 37 provides an outline of the development pathway for the offshore hydrogen network.

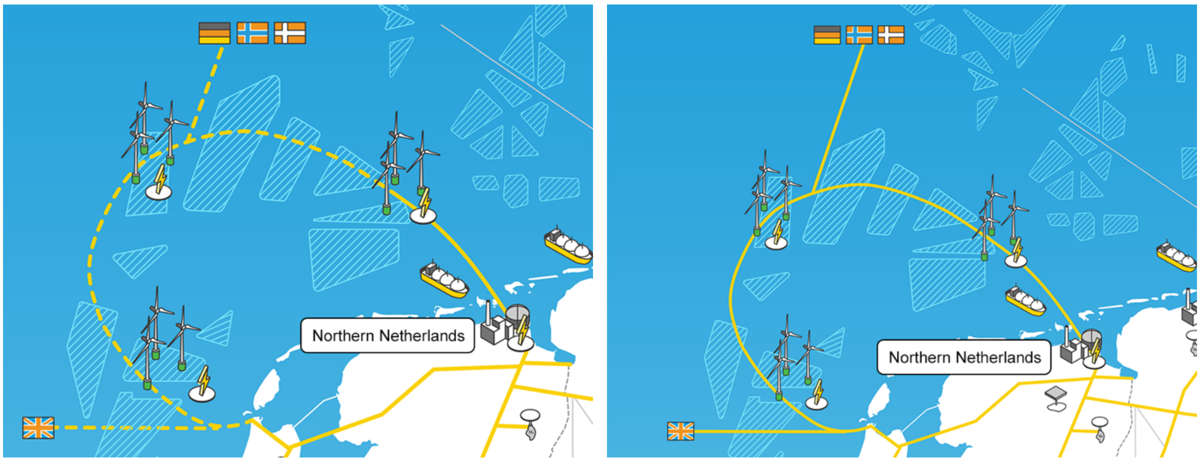


Figure 37: *Offshore hydrogen pipelines in 2030 and 2050. Solid line: completed. Dotted line: projected*

6.3.1.4 Methane network results

The current (natural) gas transport network is aligned with the demand for capacity in the market. With time, the need for (green) gas transport capacity will gradually decrease. This means that a smaller methane network will be sufficient.

In this outlook, for the first time, current gas quality levels been factored into the capacity analysis: the assumption is that network points that currently receive low-calorific gas will also receive low-calorific gas in 2050, and the same is assumed for high-calorific gas. The analysis to answer the question of whether enough pipeline capacity can be freed up in the methane network over the period up to 2050 was, therefore, done based on the assumption that the two gas quality categories will be maintained.

An assessment was made for each scenario of which pipelines, along sections of the methane network where multiple pipelines run in parallel, could be used for the hydrogen network, while still meeting the capacity needs in the methane network. The methane network will shrink due to the conversions. Pipelines to be converted to hydrogen by 2050 in the International Trade scenario, which is the scenario with the largest number of pipeline conversions, are shown in green in Figure 38.

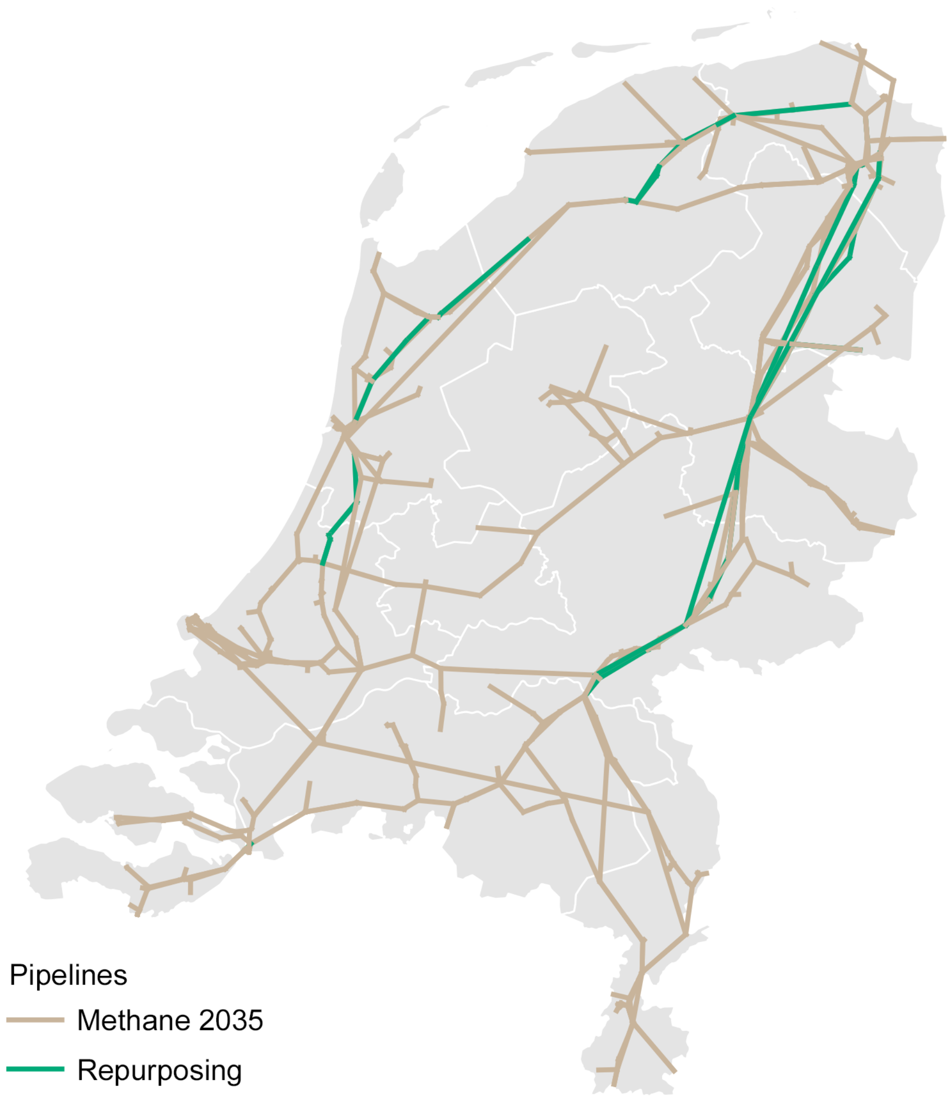


Figure 38: *Methane network and conversions in the International Trade scenario in 2050*

Due to the permitted quality bandwidths, the different gas quality categories cannot be mixed freely. In the Decentral Initiatives and European Integration scenarios, situations may arise where this scope to blend gas of differing quality is too small, causing a surplus of low-calorific gas and a shortage of high-calorific gas. Furthermore, the quality of green gas can only be controlled to a limited degree. In order to be able to transport both high-calorific and low-calorific gas in 2050, new ways will have to be created to blend both gas qualities.

Locally produced green gas that ends up in the high-pressure transport network presents yet another challenge. The fact that green gas has a different composition, in terms of oxygen content and locally added odorant for example, means that measures will have to be taken for users and for injection into the existing gas storage facilities.

6.3.2 Medium-pressure network – RDN

For a general idea of the regional distribution network, see Appendix E1. A quantitative capacity analysis of the regional distribution network was not performed for this outlook. While repurposing parts of the RDN to use them for hydrogen is possible in many situations, it will always require a customised approach in each area and it hinges on effective coordination and collaboration between all the parties involved. The regional distribution network and the networks of the regional network operators offer numerous switching possibilities to be able to solve the potential methane and hydrogen 'distribution puzzle' (see also Chapter 8 and Appendix F).

Besides using pipelines from the methane network for hydrogen, pipelines can also be used as low-pressure (approx. 8 bar) collector pipelines for green gas - like the high-pressure pipelines in Friesland and Drenthe that are currently being prepared. The increasing volumes of green gas that will have to be fed into the methane network operated by regional network operators (see 8.2.1) also means that the national methane network will have to be rearranged. Given the imbalance in green gas supply and demand, with surpluses in the summer and shortages in the winter, parts of the regional distribution network could, for example, be connected to supply green gas to a bigger market. RDN or HPGG pipelines that are no longer needed to transport natural gas can also be used as connection or collector pipelines for green gas to reduce the number of boosters (see 8.4.2) that will be needed. When hydrogen eventually makes its way into the built environment in the future (from 2035), this may lead to another rearrangement of the regional distribution network to be able to separate parts of the market to be supplied with hydrogen.

6.4 Developments in storage of hydrogen and (natural) gas

6.4.1 Operational storage and strategic storage

Energy storage is an important aspect of the energy system of the future. While some of the imbalance caused by fluctuations in energy generation and consumption can be eased using batteries, most of the storage, including to cover seasonal variations, will have to be in the form of molecules.

Exploratory calculations were made for storage in 2030, 2035, 2040 and 2050. The scenarios for 2030 and 2035 were taken from the IP: National Driver (ND), Climate Ambition (CA) and International Ambition (IA).
These scenarios align with those from II3050-2, creating a harmonised whole over time.

Besides the storage required to balance the hydrogen system, i.e. the so-called 'operational' storage, the analysis also considered the scope of possible strategic storage of gases such as methane and hydrogen. The imbalance in supply and demand differs from year to year. The basic calculations for each scenario were done based on a year with a 'normal' weather profile in terms of wind, sunshine and temperatures. The required storage will be different during a year with a 'severe' weather profile, i.e. with lower energy production due to less wind or sunshine, greater demand for heat due to low temperatures, or a combination of both. The results as shown here are based on weather conditions as they were over the 1990-2019 period.

An extension to this approach is acknowledgement of the fact that exceptionally low solar and wind power generation can also occur in consecutive years. What then happens is that the first year with a severe weather profile already drains the storage facilities, while stored energy is again needed in the following year, which also has a severe weather profile. If storage facilities cannot be refilled completely after the first year with a severe weather profile, additional 'strategic' storage will be needed to make it through subsequent winters. Another important reason to keep strategic gas reserves is that it enables a country to cover the loss of gas imports due to geopolitical developments.

6.4.2 Results

Need for storage in the scenarios

The results for methane and hydrogen for the 2030-2050 period for the various scenarios and the years with their respective weather profiles (all years between 1990 and 2019) are shown in the graphs below. The upper limit and lower limit are shown for each scenario in the corresponding colours. The grey area is the total bandwidth.[21]

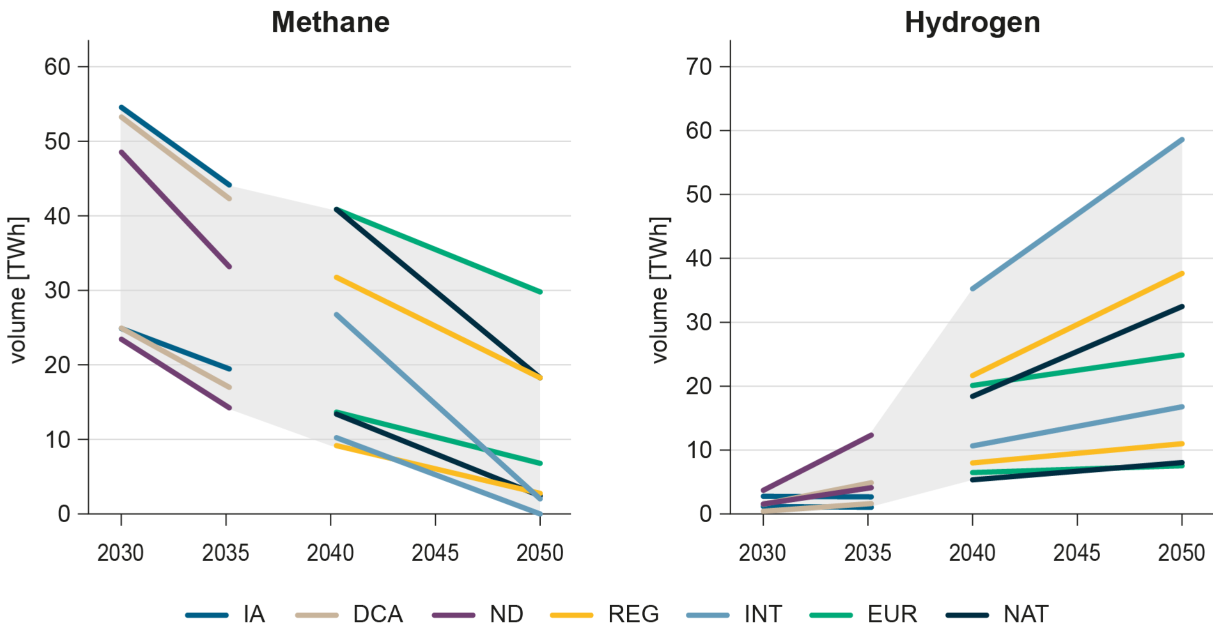


Figure 39: *Storage need for the 2030-2050 period for the various scenarios of the IP and II3050 based on weather profiles from 1990 to 2019.*

The need to store methane drops off gradually over the years, but a maximum storage requirement of approx. 30 TWh still remains in 2050, depending on the scenario. For hydrogen, the storage need will, as expected, increase to a maximum of 60 TWh by 2050.

Seasonal and flexible storage

Large-scale storage needs can be met by creating underground storage facilities in salt caverns, gas fields and aquifers. The technology for hydrogen storage in salt caverns is in a more advanced stage of development than that used to store pure hydrogen in gas fields and aquifers. An intensive, European-wide research project is meanwhile underway to assess whether storage in gas fields and/or aquifers is technically and economically feasible. Factors assessed include the integrity of the storage facility and removal of impurities from back-produced hydrogen.

By making a distinction between the ways these facilities are used, an estimate can be made as to how many caverns will be needed as a minimum, and how much storage capacity could be created in gas fields. If no other

[21] The storage volumes for methane and hydrogen are based on net calorific value and on the assumption that interaction with neighbouring countries will come in the form of annually constant import and export flows.

forms of storage are used, up to 275 caverns will be needed. This is based on 0.75 TWh per cavern for methane and 0.25 TWh per cavern for hydrogen.

TNO and EBN have already indicated[22] that a maximum of approximately 60 caverns can be created by 2050. While there is also cavern-based storage potential across the border in Germany, the obvious choice would be to develop storage facilities in empty gas fields and/or aquifers alongside hydrogen storage in salt caverns. This is currently already done for methane storage. In order to gain an initial impression, both hydrogen storage and methane storage have been split up into:

- seasonal storage, for which gas fields, for example, are very well suited, based on a storage period that has been set at 30 days for the purposes of this analysis;
- and highly flexible storage, for which caverns are better suited.

One side effect to splitting up the storage need into two different types of storage, i.e. slow and fast, is that it will reduce storage efficiency; in other words, the total need for storage volume will increase. This is down to the fact that the different types of storage facilities will work in opposite directions some of the time, with one type of storage facility sending energy into the system and the other being replenished with energy from the system at the same time.

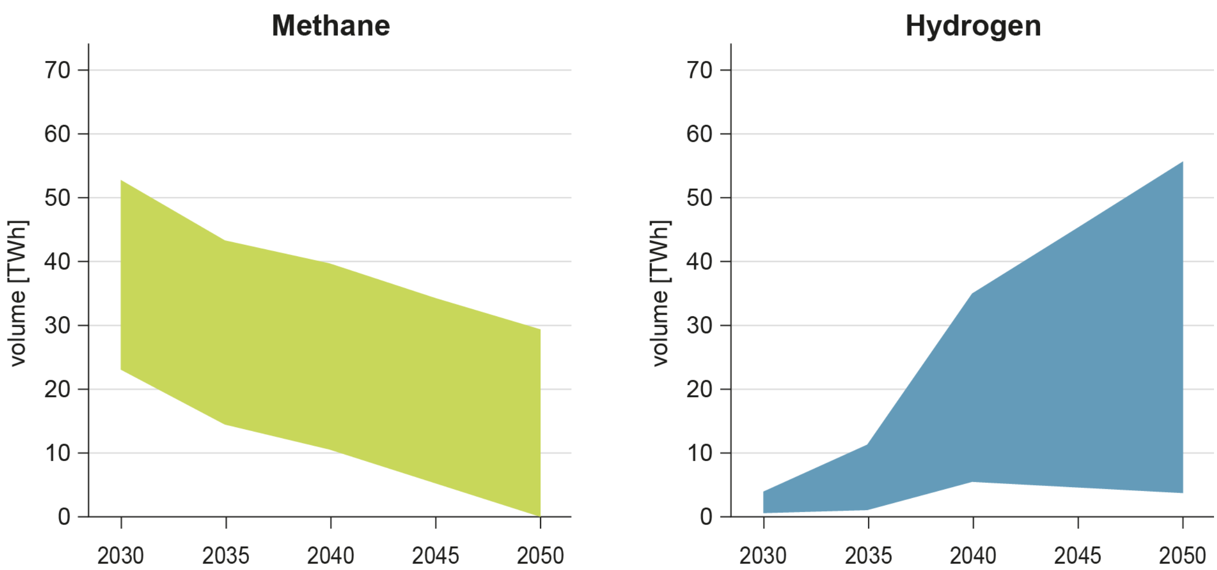


Figure 40: *Results for seasonal storage*

[22] White paper on underground energy storage (‘*Ondergrondse energieopslag*’), link: https://www.ebn.nl/feiten-en-cijfers/kennisbank/ondergrondse-energieopslag-noodzakelijk-voor-toekomstig-energiesysteem/

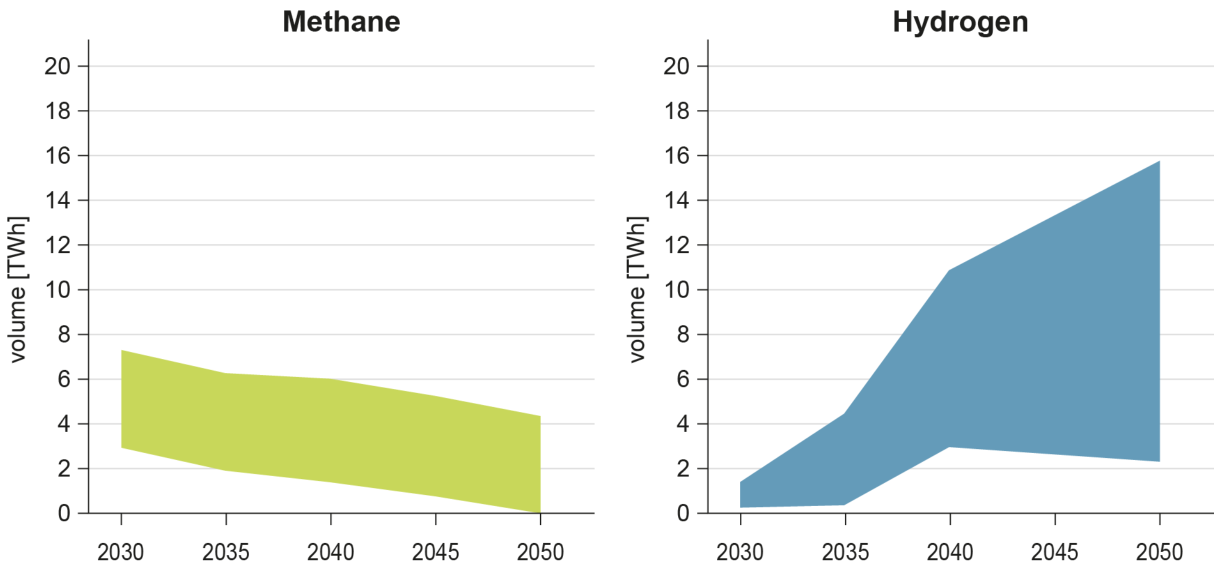


Figure 41: *Results for storage in caverns*

Despite the persistently great need for caverns through to 2050, the required number of caverns has dropped compared to the previous calculation from approximately 275 to a maximum of approximately 70 in 2050, 50 in 2040 and 15 in 2030, for hydrogen and methane combined. This is based on the assumption that the remaining volumes can be accommodated in empty gas fields - existing gas storage sites.

Alternative sources of flexibility

Some of the imbalance caused by fluctuations in energy generation and consumption can be covered by harnessing the flexibility that is intrinsic to the system resources, such as the use of aboveground tanks, scaling capacity up and down in the processes for the production of synthetic fuels and in ammonia cracking plants. The amount of flexibility available in the system depends greatly on the scenario and can be so great - up to a maximum of 38 TWh - that it affects the estimated required underground energy storage.

Strategic storage - hydrogen

It is possible to have consecutive years with exceptionally low solar and wind power generation. In order to be able to deal with this situation, additional hydrogen storage will be needed. In assessing strategic hydrogen storage needs in 2040, this section looks at a period of four years with a cold year followed by a year with low solar and wind power yields, another cold year, and another year with low solar and wind power yields. The cold year is based on the weather conditions of 2010 and the years with low solar and wind power yields are based on the weather conditions of 1997. However, the standard data set has been compiled in a way that a possible imbalance caused by high consumption due to a cold year or low supply due to low yields is automatically compensated by changing import or export volumes, so that there will never be a shortage of energy.
This ‘automatic compensation’ of extra energy demand by changing import or export volumes ensures that there will never be a shortage of hydrogen. The question is, however, whether this is always realistic. After all, when it is cold in the Netherlands or when solar or wind power yields are low, this is likely to also be the case in neighbouring countries. This is why average import/export levels, from an average weather profile year (2012), are assumed for the calculations. The difference between import/export in the ‘average year’ and the import/export required to balance the four above-mentioned ‘severe years’ is a measure for the required strategic storage volume.

The year 2040 in the Decentral Initiatives scenario (DEC) is taken as an example. In this scenario, exports are varied to balance supply and demand. The export levels are as follows for the four severe years and for the average weather profile year of 2012:

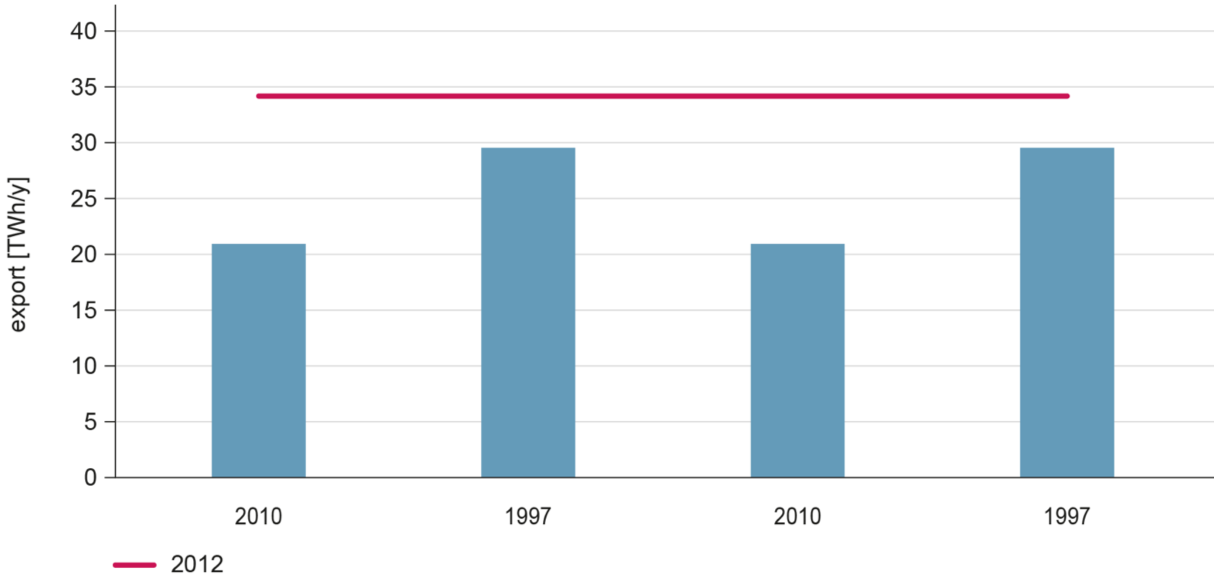


Figure 42: *Balancing export levels as a function of the weather profile in 2040 in the Decentral Initiatives scenario.*

The graph shows that export levels in the four severe years are lower than in the average year. If the level for the average year is considered to be realistic, the conclusion must be that there is a shortage in the severe years. The difference between the red line and the blue bar shows the shortage on an annual basis. The total shortage over the four severe years amounts to approximately 35 TWh for this scenario. For the other three scenarios (INT, EUR and NAT), the shortage is 59, 35 and 40 TWh respectively. Based on the assumptions chosen here, the strategic reserve would have to be between 35 and 59 TWh, depending on the scenario.

6.5 Variations on the scenarios

Different variations on the four scenarios were also analysed, both in a qualitative and in a quantitative sense. A general conclusion is that the hydrogen network section that runs to Belgium through Zeeland province is used to the maximum possible degree in the base scenarios. If a variation on a scenario leads to greater export capacity to Belgium, this section would have to be upgraded by adding pipeline capacity or compression.

6.5.1 Synthetic fuels

The assumed synthetic fuel production in the Netherlands has consequences for, among other things, hydrogen demand (see 2.3.2). For the National Leadership and European Integration scenarios, the network consequences of two extremes were determined: no synthetic fuel production and high synthetic fuel production. Especially in the National Leadership scenario, high synthetic fuel production will require additional pipeline upgrades in the hydrogen network (approx. 600 km of new pipelines) and additional compression sites due to the much greater maximum transport capacity for the network, approximately 50% more compared to the base scenario.

6.5.2 Transit

The consequences were also analysed of additional hydrogen flows crossing the Netherlands for the kind of hydrogen network that is needed in the National Leadership scenario. These are flows from the ports of Rotterdam, IJmond, Den Helder and Eemshaven to Belgium (approx. 4 TWh) and Germany (approx. 150 TWh). Besides upgrading the section that runs through Zeeland province to Belgium, an additional compression site will also be needed. In the base scenarios, the route to Belgium via Zeeland province is already used to full capacity. A small volume of additional transport on top of the National Leadership scenario will, therefore, trigger a need for investment. The route to Germany still has considerable transport space available in the base scenarios.
For large volumes of additional transit to Germany on top of the National Leadership scenario, adding another compressor will be sufficient.

6.5.3 The weather profile of 2010

For the National Leadership and International Trade base scenarios, an assessment was made of the consequences that basing supply and demand on the 2010 weather profile instead of on the average weather profile will have on the required transport network (see 4.2.6). The year 2010 has the most ‘severe’ weather profile of the current climate reference period (1990-2019), with a prolonged cold period and with low temperatures that lead to high demand for heat. When using the weather profile of 2010 as the basis for calculations instead of 2012, the two scenarios mentioned above will require approximately 90 km and 150 km respectively in additional pipeline upgrades, i.e. new pipelines, with additional compression. The influence of the choice of weather profile is such that conclusions based on a single weather profile can only be indicative.

6.5.4 Ammonia and ammonia transport

All four scenarios, and especially European Integration and International Trade, assume that hydrogen will also be imported. In what form hydrogen will reach the Netherlands in 2050 is impossible to say exactly, but it is fairly certain that the bulk of it will be imported by sea in the form of ammonia (NH_3) or as liquid hydrogen. This is cooled and pressurised, or bound to other organic molecules, so as to create liquid organic hydrogen carriers (LOHC) that are easy to transport. There are also users who use ammonia as a feedstock or fuel, such as the fertiliser industry, international shipping and power plants. Hydrogen transport in the form of ammonia is an interesting option for these purposes, because the imported ammonia will then not have to be converted into hydrogen and back to ammoniac, thus preventing conversion losses. There is great potential demand for ammonia: the scenarios anticipate that 10-15% of hydrogen demand will come from the fertiliser industry in 2050, and 20-40% from power plants.

While there is little experience with ammonia, the consensus is that major ammonia flows on land should be transported through shielded pipelines through sparsely populated areas. The ammonia is liquid, and cooled for short distances and pressurised for long distances. However, strict safety requirements due to the health risks and legislation mean that there are limited ammonia transport options available. Transport pipelines with a capacity capped at approximately 1.5 GW seem feasible even so. Locations that can be reached by ship or places where local storage in ammonia tanks is possible would help in reducing the required capacity for transport by pipeline.

The fertiliser industry in Sluiskil in Zeeland province allows easy access by ship. The Chemelot site in Limburg province can be connected to import flows from the port of Rotterdam via the Delta Rhine Corridor pipelines, whereby one single pipeline is likely to suffice through to 2030 at least, given the initial estimate of supply and demand.

Seeing as the extent of ammonia transport by pipeline appears to be limited initially (roughly 1.5 GW in the Netherlands), the impact on the hydrogen network will be minor. The hydrogen network's capacity is far greater.

If cracking plants that convert ammonia into hydrogen can be used flexibly, this could provide additional flexibility and perhaps reduce the need for storage in the hydrogen system. This will have to be assessed in greater detail.

For a more detailed elaboration of ammonia transport, see Appendix E.

Chapter 7

Impact on the regional electricity infrastructure

7.1 Conclusions and recommendations

7.1.1 Conclusions

- To facilitate the increase in the peak load, for both generation and consumption, the infrastructure for the substations must at least double in capacity in the International Trade scenario, or possibly even triple in the Decentral Initiatives scenario, in the period to 2050.

- The regional network operators will need to go to work in almost every neighbourhood. The low-voltage grid needs to be expanded by adding 20% to 30% more cables, and new MV/LV transformer stations need to be added, to the tune of an extra 40% to 55%. The intermediate MV grid also needs to be expanded by 35% to 45%.

- Most of the capacity expansion work must be done during the next 10 years. The greatest growth in generation and energy demand electrification is expected in this period. This brings the main push to complete the required grid upgrades forward compared to II3050 edition 1. Consequently, much work must be done earlier. This is a result of the more ambitious CO_2 reduction targets, which are incorporated in the new scenarios of II3050-2 (the scenarios for the 2024 IP have been revised substantially upwards compared to IP2022).

- The differences between the scenarios in their impact on the grid in 2050 are now smaller than in II3050-1. This is a consequence of the net effect of the scenario choices, including increases in rooftop solar capacity and enhanced electrification in all scenarios.

- The nature and size of local bottlenecks may vary from one scenario to the other. In general, bottlenecks in urban areas are more often consumption-driven, as opposed to those in rural areas, which tend to be generation-driven.

- Through curtailment (50% to 60%), also known as capping the solar peak by using an undersized inverter relative to the installed solar panel power, the generation peaks in the grid are at least halved in all scenarios. Despite the application of curtailment, generation remains a determining factor for a large proportion of the bottlenecks, for all voltage levels and in all scenarios. Curtailment has a limited effect on the energy yield, but a major effect on the required infrastructure. The limited energy yield loss (10% to 20%) occurs at times when there are huge generation surpluses, so this energy is actually of little value from a system perspective. Currently, 50% curtailment is already encouraged under government grant schemes (SDE++) for large-scale installations. There is no such incentive yet for small-scale installations, including rooftop solar panel systems for households.

- Flexibility resources, which are deployed to balance the system, cause the total consumption peak at the interconnection point level to increase at least one and a half times unless they are connected in a scarcity-neutral manner. Scarcity-neutral connection prevents flexibility resources from exacerbating grid congestion. In the case of most stations, this implies a restriction on flexibility resources of less than 200 hours per year. If flexibility resources are not connected in a scarcity-neutral manner, the capacity requirement will increase further by 40% to 75% in 2050.

7.1.2 Recommendations

- The actual infrastructure development path is heavily influenced by the limited availability of skilled workers and the materials required, and by long project completion times. The extent of this execution challenge for the next 10 years is the focus of the upcoming investment plan (2024 IP). Only after this exercise will there be a better understanding of the work that will carry over to the period after 2035, which will in turn allow a more accurate assessment of the expected development path.

- To avoid unnecessary investments and improve the ability to execute the work, significant curtailment of a magnitude of 50% to 60% must be implemented in a timely manner - before 2025. This applies to all solar power generation categories, both solar farms and small-scale and large-scale rooftop solar facilities. Timely implementation is important because the growth curve is currently in the exponential phase. With that in mind, it is also important, from a societal point of view, to assess how existing customers are treated.

- Scarcity-neutral connection of flexibility resources can avoid bottlenecks. That also leads to more efficient use of the available infrastructure. Deployment frameworks for connecting flexibility resources in a scarcity-neutral manner need to be put in place as soon as possible. Netbeheer Nederland's recent proposed deployment framework for large-scale batteries represents an initial step in this direction.

- Because the size and nature of each bottleneck varies per scenario, it is difficult to act on them effectively. Adequate control and frameworks are needed to ensure the greatest possible efficiency in tackling the work. In this context, the process for integral programme development, in which local and regional plans are worked out in concrete form, fitted together and prioritised together with stakeholders, is also important. An example is translating the Transition Vision Statement for Heating (also known as the Heating Programme, following the introduction of the Dutch Environment and Planning Act) into a District Implementation Plan, whereby the required space is reserved for grid infrastructure to allow the network operator to get to work fast in the district.

7.2 Regional electricity grids

The power transmission and distribution grids[23] have historically been constructed to transmit electricity from large central power stations to the mains power connection of local end-users, such as households or industry.
To make this possible, electricity grids at the local, regional and national level are interconnected to form a single interconnected electricity grid.

[23] This description is partly based on the document 'Basisinformatie over energie-infrastructuur: opgesteld voor de regionale energie strategieën' [Basic information on energy infrastructure: prepared for the regional energy strategies] published by Netbeheer Nederland in October 2019.

Developments in the energy transition, including the growth of renewable power generation, electric mobility, electrification of heat demand and action to make industry more sustainable, mean that major adjustments must be made to the regional electricity grid. These developments are unfolding at a rapid pace, and the locations where the new power generation capacity and demand for power emerge are not always known far in advance.

The above developments create a significant expansion and investment challenge for the regional network operators. This is already an area of focus for them, but much more is needed. This chapter identifies what is additionally needed to achieve the transition to a completely climate-neutral energy system by 2050. The impact is determined for the different voltage levels and components in the regional grid.

The regional grid in the Netherlands comprises the following voltage levels:
- Intermediate voltage between 25 and 66 kV (IV);
- Medium voltage between 3 and 23 kV (MV);
- Low voltage 0.4 kV[24] (LV).

High-voltage (HV) grids carry a voltage of more than 100 kV. These grids are operated by TenneT and are separate from the regional electricity grids. The analyses of the main voltage grids are presented in Chapter 5.

Important components of regional electricity grids include various types of cable connections, low-voltage substations and various types of grid station, such as transformer stations, control and switching stations and distribution stations. In HV-IV and HV-MV transformer stations, high voltage (110 to 150 kV) is converted to an intermediate, or medium voltage. These are the substations where TenneT's national grid connects to the regional network operator's grid. There are also several MV-MV control and switching stations that control voltage quality and further distribute electricity. These stations play an important role in supplying power to cities and major industrial sites, and there are often several stations of this type in a residential area. Solar farms are connected directly to this type of station, as are large businesses or other installations characterised by a high power demand. Substations (MV-LV) handle transformation from medium to low voltage. The low-voltage cables for individual connections for homes, public lighting and electric vehicle charging points, for example, are connected to the substations. More information on the reliability and the different grid areas of the network operators is available on NetbeheerNederland.nl. The size of the regional grid system is shown in Table 9.

Table 9: *Size of the current regional grid system.*

	Current
HV/MV stations [number]	237
MV, MV/MV, IV/MV stations [number]	1,868
MV/LV stations [number]	95,239
MV cables [km]	111,274
LV cables [km]	186,918

24 400V across three phases. A connection with just one phase is 230V, the voltage at the wall socket.

7.3 Method for analysing bottlenecks and developing grid solutions

To investigate what changes are required to the regional grids, the climate-neutral scenarios are fed into grid simulation models. Each network operator uses its own grid model for this purpose.

The models include a digitised representation of the grid, with the various grid components and their configuration, and data on how the grid is currently loaded. That data is made up of historical or current measurement data relating to the state of the grid and the current load factor of the various grid components The scenarios are then simulated in these models to assess the future load. The outcomes are used to identify where bottlenecks will occur, their impact and what future changes are needed to resolve these bottlenecks.

Different sets of data need to be combined to simulate the future scenarios in the grid models:

- The aggregate supply or demand profile per category. For example: the generation profile of the total installed capacity of solar PV on residential rooftops, or the charging demand for the total number of electric cars.

- The 'regionalisation' of all segments. This is the breakdown across the Netherlands, down to the level of Statistics Netherlands neighbourhood codes: i.e. the demand and generation per neighbourhood in the different segments. The regionalisation approach is described in Chapter 4. The simulation allocates the generation and demand per neighbourhood to the existing assets. This is done in accordance with the current service areas supplied by the stations. Each station has a specific service area, just as each cable has a number of specific customers connected to it.

- The hourly deployment profile of each segment. For example, how solar PV production varies during the day in a simulated weather profile year, based on historical meteorological data. A number of segments make a static contribution to flexibility, and this is taken into account in the profile. This applies, for example, to solar PV (curtailment), to hybrid heat pumps (switching to gas when it gets very cold) and to electric cars (smart charging profile).

7.4 Bottlenecks and infrastructure developments towards 2050

Before we describe the bottlenecks and infrastructure required, please note the following: II3050 is an exploratory outlook to assess the impact of climate-neutral scenarios on the infrastructure. So it is not intended as a tool to determine actual grid investments. However, in the interest of promoting general understanding, the infrastructure needs are described in terms of grid investments.

As we progress towards 2050, additional grid infrastructure will be needed: the peak load for the substations, i.e. the transfer points between the national and the regional grid, will at least double in the International Trade scenario, and triple in the Decentral Initiatives scenario. In terms of the underlying grid, network operators will need to upgrade cables and add grid stations in almost every neighbourhood. The LV cables need to be expanded by 20% to 30% (compared to the current distance in km), 40% to 60% more MV/LV stations need to be added, and as many existing stations need a capacity upgrade. The intermediate MV grid also needs to be expanded by 35% to 45%.

7.4.1 Substations

The total consumption peak[25] at all substations in 2050 varies between 36 GW in the Decentral Initiatives scenario and 32 GW in the International Trade scenario; see Figure 43. Consumption peak – Scarcity-neutral use of flexibility resources.
The total generation peak varies between 48 GW in the Decentral Initiatives scenario and 27 GW in the International Trade scenario, as shown in Figure 43. Generation peak - Scarcity-neutral use of flexibility resources. Compared to the current situation, the peak load doubles or triples. This also necessitates a similar growth in infrastructure[26]. The total additional capacity requirement[27] for the substations in the period to 2050 is shown in Figure 44.

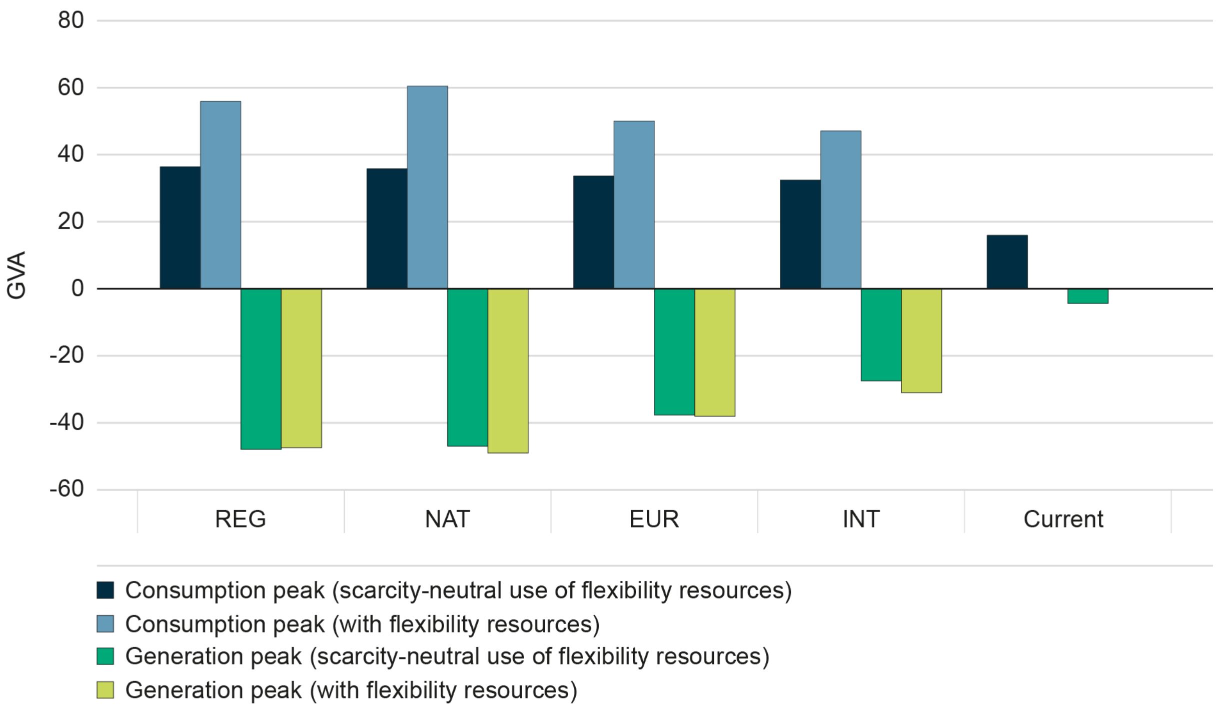


Figure 43: *Sum of the peak loads (generation and consumption) at all substations, situation with flexibility resources connected in a scarcity-neutral and non-scarcity-neutral manner.*

The above results assume scarcity-neutral connection of flexibility resources. This means that flexibility resources must not exacerbate congestion. Netbeheer Nederland recently proposed a deployment framework for connecting large batteries in a scarcity-neutral manner[28]. Figure 43 shows that the consumption peaks are at least one and a half times greater if flexibility resources are not connected in a scarcity-neutral manner. As a consequence of the increase in the peaks, the capacity requirement in 2050 will increase further by 40% to 75%; see also Figure 44.

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25 The sum of all the individual peaks at the connector stations.

26 Assuming comparable asset utilisation rates in 2050 compared to today.

27 Allowance has been made here for the current N-0 limits for generation and N-1 for consumption.

28 See also 'NBNL, Nieuw inpassingskader voor grote batterijen moet netcongestie verminderen' [NBNL, New deployment framework for large batteries is intended to reduce grid congestion], https://www.netbeheernederland.nl/nieuws/nieuw-inpassingskader-voor-grote-batterijen-moet-netcongestie-verminderen-1596.

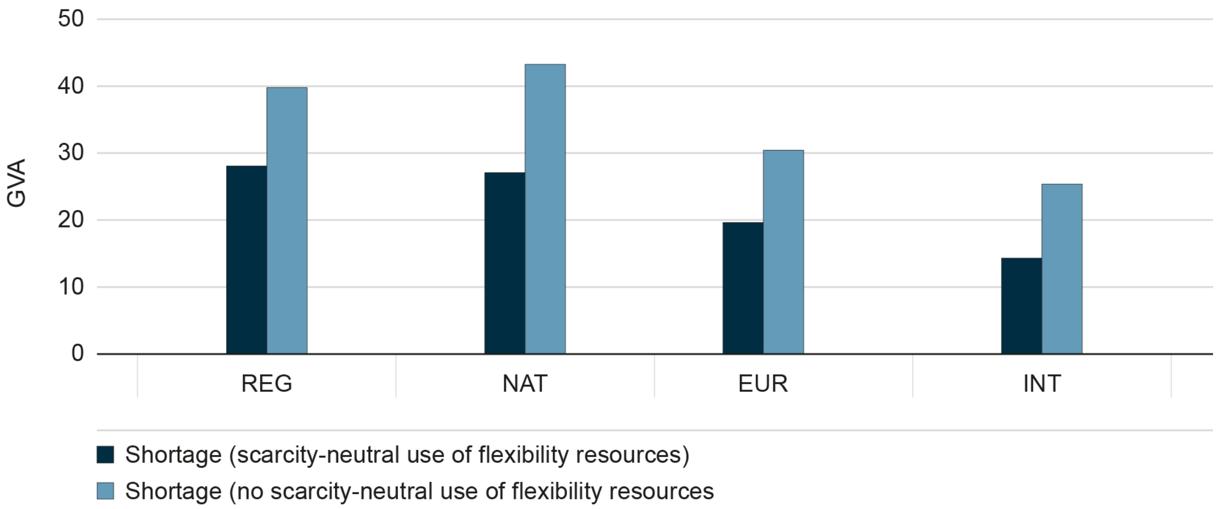

Figure 44: *Sum of the total extra capacity requirement at all substations, situation with flexibility resources connected in a scarcity-neutral and non-scarcity-neutral manner.*

The increase in the capacity requirement is primarily a result of an increase in the consumption peaks. The increase in the consumption peaks is caused by a mismatch between the local situation and the national situation during a limited number of hours. In this study, the flexibility resources respond to the national situation. The simulation of the future national energy market (in the period to 2050) and deployment of the flexibility resources are based on national electricity prices. This applies to the flexibility resources in all the voltage levels. In practice, flexibility resources will also be deployed in imbalance markets, thereby making the behaviour of flexibility uncertain and unpredictable. This study attempts to assess this by looking purely at the national electricity price. This is an important consideration, especially when the conclusions in this study about the impact of flexibility are compared with other studies. Specifically, the electricity price development in the period to 2050 will increasingly be driven by the large amounts of generation from offshore wind, which will result in an increase in the local grid load. To give a concrete example of the above: offshore wind plays an important role in the national supply mix, and the power it generates is fed into the national HV grid. Say there is a local consumption peak on a cold day during the winter. At the same time, a lot of power generated by offshore wind may be available, meaning that the electricity prices are low and that the local availability of the flexibility resources will decrease, due, for example, to battery charging. This results in additional loading, on top of the local consumption peak.

In respect of generation peaks, flexibility has little or no effect at the connector point level. This is because the peaks are mainly caused by solar power, as wind power is often centrally connected. During the hours of sunshine, there is often little wind, so the regionally generated electricity is used to meet national demand, and there is no need to deploy flexibility. It is worth noting that a very significant part of the generation peak has already been tempered by applying curtailment. So, in general, there is no decrease or increase in the generation peak at the connector point level due to the deployment of flexibility. The following exceptions apply:

- Stations with onshore wind: here there is often a decrease in the generation peak, because the local situation correlates strongly with the national situation due to the wind component.

- Stations with more flexible power than local supply: here the deployment of flexibility resources can cause an increase in the generation peak. At times when there is a rapid decrease in supply, due to less wind and sunshine, all flexibility resources can start delivering power for the short term.

In the case of most stations (approx. 85%[29]), this implies a restriction for scarcity-neutrality purposes of less than 200 hours per year. This concerns about 1% of the energy consumed by flexibility resources, so this limitation only results in a small deviation in terms of the annual balance. An example of exacerbation of the consumption peak due to the deployment of flexibility is shown in Figure 45. This figure also shows that the deployment of flexibility for a limited number of hours per year exacerbates the peak (consumption) load.

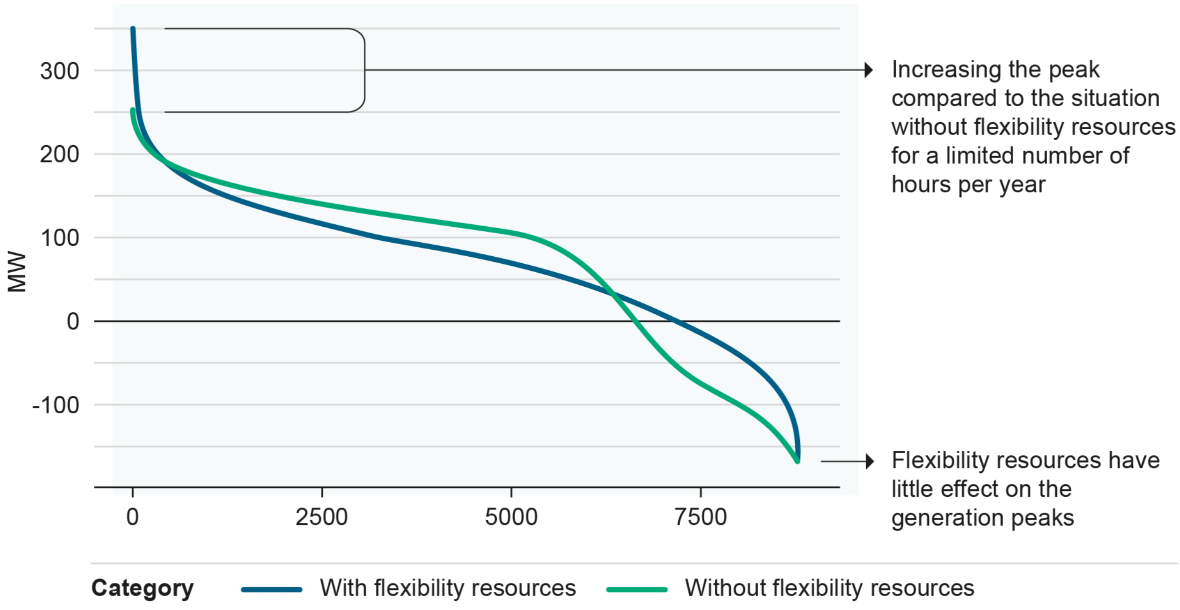

Figure 45: *Example of a load duration curve for a substation in 2050. Here we see that the deployment of flexibility resources for a limited number of hours per year causes a higher consumption peak.*

Because flexibility is of primary importance in maintaining the balance, scarcity-neutral deployment of flexibility has the consequence that additional flexibility may need to be added to the system, even though the imbalance is limited - less than 200 hours a year. It is difficult to quantify what this rebalancing involves in this study because of the limitations of Quintel's Energy Transition Model as used here, but it is a relevant topic that should be explored in a follow-up study. Due to the limited period of time involved and high impact (40% to 75% increase in the capacity requirement), scarcity-neutral connection of flexibility resources is desirable from a societal point of view to avoid major grid upgrades with a low utilisation rate. An example of scarcity-neutral connection of flexibility resources is grid-aware charging at public charging points. In this situation, the charging capacity is limited by the grid operator when congestion occurs. The effects of grid-aware charging have been taken into account by adapting the charging profiles.

Despite the large capacities of solar power in all scenarios, the total generation peaks in 2050 remain relatively limited due to the application of curtailment. In the Decentral Initiatives scenario (DEC), there is about 130 GW of installed solar PV capacity. Without curtailment, the total generation peak increases by about 80 GW. Figure 46 shows the effect of curtailment on the sum of the generation peaks at the substations. In all scenarios, the total (net) generation peak is at least twice as large if curtailment is not used.

The scenarios assume 50% (EUR/INT) to 60% (REG/NAT) curtailment for all solar PV categories. This results in a limited energy yield loss (10% to 20%). The loss occurs at times when there are huge generation surpluses, so

[29] At the remaining 15% of the stations, the power capacities of the flexibility resources are much more dominant relative to the local load and generation. As a result, more than 200 hours of additional control is required per year to prevent an increase in the peak load.

this energy is actually of little value from a system perspective. In addition, large delivery peaks only manifest themselves during a few hours per year. Due to the low utilisation rate, building additional infrastructure for this high capacity need is inefficient. Currently, 50% curtailment is also encouraged under government grant schemes (SDE++) for large-scale installations. There is no such incentive yet for small-scale installations, including rooftop solar panel systems for households, or for large-scale installations outside the scope of the SDE++ grant scheme. Before the introduction of the SDE++ grant scheme, 30% curtailment for large-scale installations had been the standard for some time. This is also laid down in the 'Convenant Zon Betaalbaar op het Net' [Covenant for Affordable Solar Power on the Grid][30]. In addition, the aggregated peak load of small-scale installations on the higher voltage levels is also typically limited to a maximum of 70% of the installed solar panel capacity. This is mainly a result of orientation differences, shade on the panels and individual installation losses. This is why Figure 46 also includes the 30% peak load curtailment as a reference; this presents a picture of the current situation. Currently, the growth of solar power is in the exponential phase, so implementing increased curtailment in a timely manner for all solar categories is important.

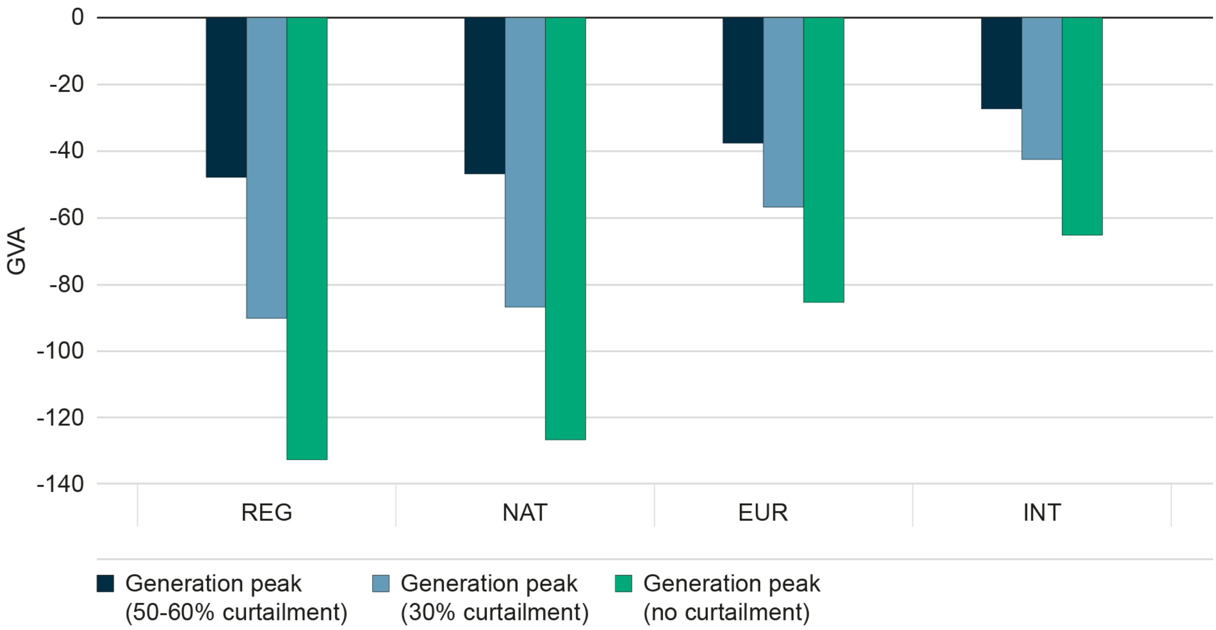

Figure 46: *Sum of the peak loads at all substations, situation with 50% to 60% curtailment and without curtailment.*

II3050-2 shows smaller differences in the maximum generation and consumption peaks between the scenarios than II3050-1. With regard to generation, the scenarios now converge more closely due to growth in rooftop solar systems and the higher curtailment assumptions. In the 2050 scenarios, there are more rooftop solar systems in the second edition of II3050. This is a consequence of the current trends, including the rapid adoption of solar panels by households, the RES regions' firm commitment to large-scale rooftop solar power, the addition of solar panels to the Erkende Maatregelen Lijst/EML [Approved Measures List] and also the possible future obligation measure[31]. The upward revision of the curtailment assumptions (from 33% in the first edition of II3050 to 50%-60% in the second edition), is also a consequence of the current trends. This is illustrated by the requirement for 50%

[30] https://www.netbeheernederland.nl/_upload/Files/Convenant_Zon_Betaalbaar_op_het_Net_186.pdf (19 November 2020).

[31] Cabinet's Solar Power Memorandum: *'The extension of the draft Order in Council relating to the previously proposed customisation powers in the Decree on Building Structures in Living Environments (Besluit Bouwwerken Leefomgeving, BBL), which are intended to allow municipalities to make renewable energy systems on rooftops obligatory for buildings designated to be used for industry, to include all non-residential buildings and to allow full utilisation of the roof for solar panels in the case of roofs measuring 250m2 or more. The target date for entry into force is 2024.'*
This obligation measure is also in line with the proposed policy of RepowerEU, as elaborated in the EU Solar Energy Strategy.

curtailment under the current government grant schemes (SDE++) for large-scale installations. There is no such incentive yet for small-scale installations, including rooftop solar panel systems for households. The scenarios have also converged more closely in respect of the assumptions relating to energy demand electrification. An example is the change to the assumptions regarding the adoption of electric passenger transport. The adoptions in the low scenarios have been revised upward, reducing the difference between the scenarios.

7.4.1 Regional differences between substations

Bottlenecks will occur in the future at almost all substations and investments are needed. The nature and size of the bottleneck varies per substation and per scenario. Despite the high degree of curtailment, generation is still often the main bottleneck. Figure 47 shows a geographical overview of the dominant cause of the bottlenecks in each scenario. Especially in rural areas, the generation peaks exceed the consumption peaks (Figure 47, orange). In urban areas, energy demand electrification is the main bottleneck (Figure 47, purple)[32].

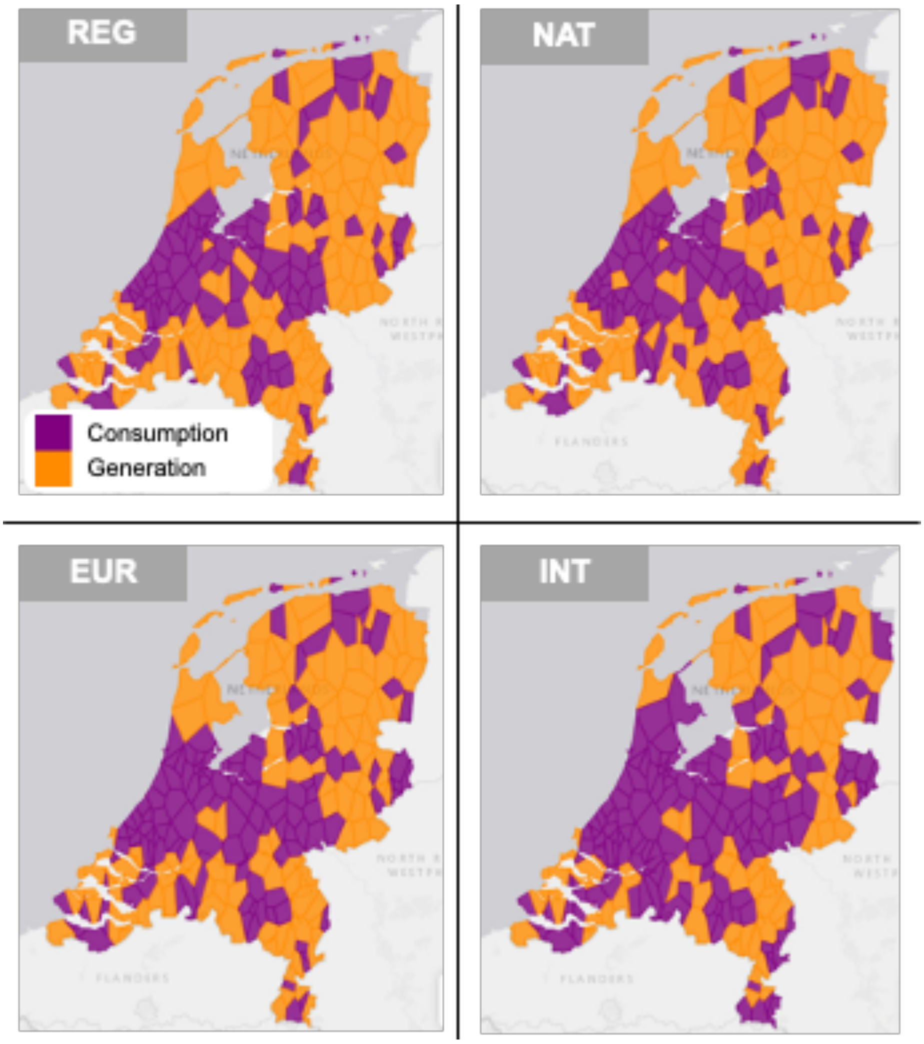

Figure 47: *Geographic overview of bottleneck causes due to consumption or generation, per substation - assuming scarcity-neutral flexibility.*

[32] Allowance has been made here for the current N-0 limits for generation and N-1 for consumption.

Figure 48 shows how the shortfalls per substation are distributed in each scenario. There are areas where in one scenario hardly any investment is needed, while in another the required capacity doubles. For the Netherlands as a whole, the substation capacity needs to double or even triple. Many choices still need to be made before the locations where the additional capacity is needed can be determined exactly. If the network operators are to be asked to invest now in preparation for 2050, providing sufficient guidance and frameworks to prevent unnecessary investments is crucial. An example would be a policy that determines which energy-intensive industries are appropriate in a climate-neutral Netherlands.

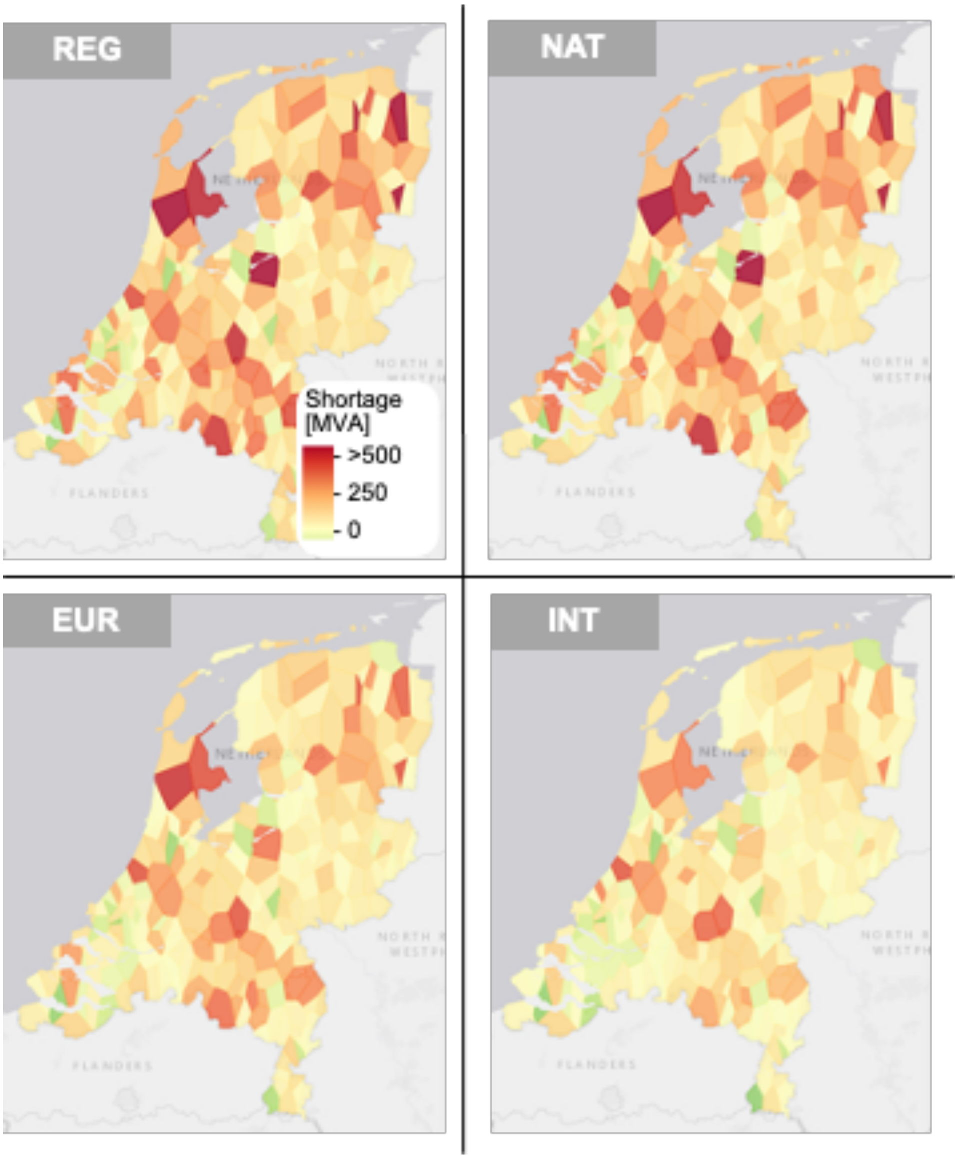

Figure 48: *Geographic overview of shortfalls per substation in 2050, assuming scarcity-neutral flexibility, with the indicative supply areas.*

7.4.2 Underlying grid

In terms of the underlying grid, the network operator will need to upgrade cables and add grid stations in almost every neighbourhood. Table 10 shows that the LV network needs to be expanded by 20% to 30% compared with the current kilometres of cable, and that 40% to 55% more MV/LV transformer stations need to be added. This has space utilisation implications, both below and above ground. There are often already several MV/LV stations in a neighbourhood, and where necessary and possible, these stations will be upgraded. But new stations must also be added. In addition, the MV network must also be expanded: the number of kilometres of cables by 35% to 45% and the number of IV/MV and MV/MV stations by 35% to 40%.

Table 10: *Numbers per asset type per scenario for 2050. The current number is included as a reference.*

II3050 edition 2	Current	Decentral Initiatives	National leadership	European integration	International trade
					Stations (number)
MV/LV stations	95,200	149100 (+57%)	148000 (+55%)	143000 (+50%)	132200 (+39%)
MV, MV/MV, IV/MV stations	1,870	2600 (+39%)	2580 (+38%)	2500 (+34%)	2480 (+33%)
					Cables [km]
MV cables	111,300	161100 (+45%)	161100 (+45%)	158100 (+42%)	151100 (+36%)
LV cables [km]	186,900	241000 (+29%)	240700 (+29%)	233900 (+25%)	226900 (+21%)

7.4.3 Flexibility in the underlying grids

Like for the substations, load peaks increase for the underlying grid if flexibility is not connected in a scarcity-neutral manner. The effects of the behaviour of the flexibility resources in the underlying grid were analysed based on a calculation performed for Stedin's network.

In all scenarios, 60% to 70% of the flexibility impact at the substations originates from flexibility resources in the low-voltage grid. About 50% of this contribution is from home batteries and 50% from EV batteries.

So scarcity-neutral connection of flexibility resources yields significant benefits in all the voltage levels. With regard to LV cables and MV cables, it reduces overloaded cables by about 20% to 40% (Figure 49). In the MV/LV stations, the reduction is 10% to 20%. For 70% to 80% of the stations, scarcity-neutral connection means a limitation on the flexibility resources of less than 200 hours per year. We conclude this from an analysis based on the difference in overload hours at MV/LV stations.

The above results are a preliminary analysis. The effect of scarcity-neutral connection may be greater in lower voltage levels. This is because the analysis uses profiles with low simultaneity. However, simultaneity is higher in the lower voltage levels.

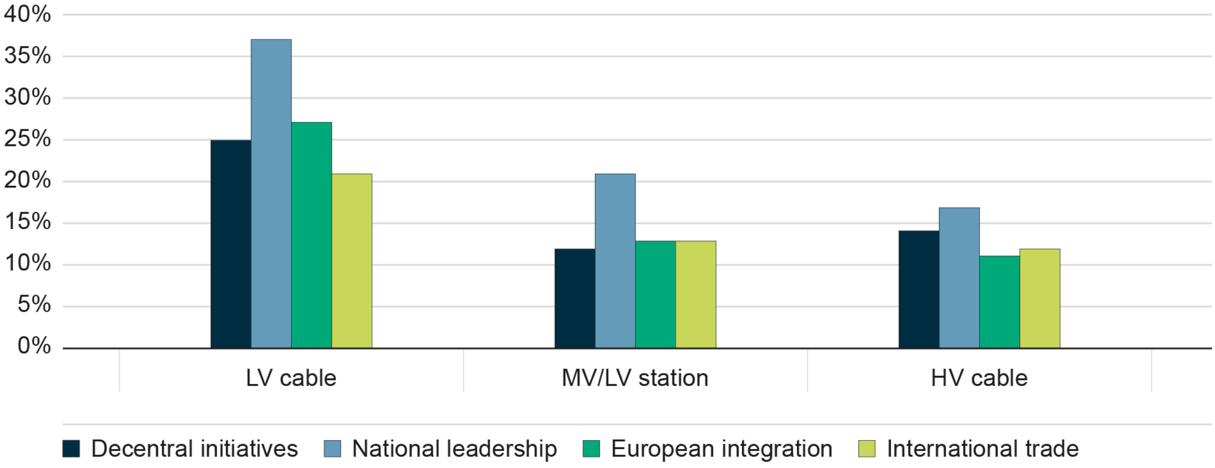

Figure 49: *Impact of flexibility quantified for the different grid components in Stedin's area for all scenarios in 2050.*

7.5 Development path towards 2050

This chapter discusses the development path of the regional network operators' electricity infrastructure in the period to 2050. The development path towards 2050 is outlined using the three scenarios for the 2024 IP (IA, CA and ND) for horizon year 2035 and the four scenarios of II3050-2 for 2050 (REG/NAT/EUR/INT). The grid impacts were modelled differently for horizon year 2035 compared to horizon year 2050. The effect of this on the results is also explained in this section.

7.5.1 Substations

Figure 50 shows the development of total consumption and generation peaks at the substations. This also shows that most of the capacity expansion needs to be completed in the next 10 years, as that is when the greatest growth in generation and energy demand electrification is expected.[33] This brings the main push for the work further forward (compared to the first edition of II3050), due to the revised CO_2 reduction target in 2030. The scenarios for the 2024 IP have been revised upward substantially in comparison to the scenarios for the 2022 IP. In II3050-1, the main push in the work package was still situated between 2030 and 2035. In II3050-2, it has moved further forward.

[33] For 2035, limited allowance has been made for curtailment: a maximum of 50% for large-scale rooftop solar systems and a maximum of 30% for small-scale rooftop solar systems.

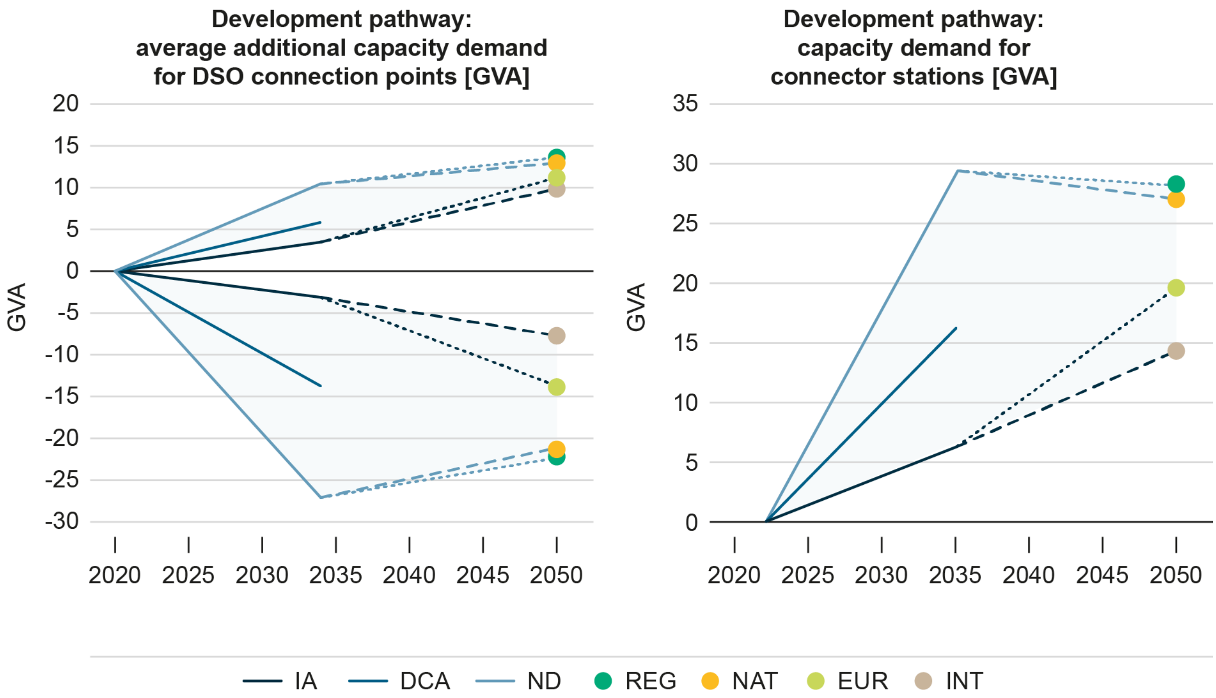

Figure 50: *Development path of the total power requirement for consumption and generation (left) and the additional capacity requirement (right) at the substations. Lines show how the different scenarios are linked to each other. Due to an increase in curtailment assumptions, there is a downward trend in the power requirement between 2035 and 2050 in the European Integration and International Trade scenarios.*

Figure 50 shows that the spread of the power requirement at the substations in 2050 is smaller than in 2035. This applies to both the consumption and generation power requirement. This is partly because the 2024 IP scenarios present a wider spread in the growth of technologies toward 2035. This spread is also a result of curtailment assumptions - the increase in curtailment between 2035 and 2050 - and the difference in modelling between the investment plans and II3050-2. This is explained in more detail below.

Figure 50 shows limited growth in consumption peaks between 2035 and 2050. It is important to note that the 2035 consumption bottlenecks of the regional network operators are based on a bottom-up approach that takes the current load at the existing stations as the starting point. For the overall final picture in 2050, a top-down approach was used in II3050-2, involving a different methodology - profiles and regionalisation - and sometimes also differences in the drivers and technologies compared with the methodology used for the investment plans (IPs). The expected increase in major new industrial customers at regional network operator level is an example of this. In II3050-2, average profiles and growth paths were calculated specifically by industry sector based on average national figures. Most regional network operators also base the projected growth in their 2035 calculations on the current customer funnel of new and existing industrial customers and on current measured load and other types of data specific to industrial customers. Due to these kinds of differences, the overall final picture in 2050 is expected to be too low compared to the 2035 calculation. In other words, greater growth in consumption than that currently shown in the development paths is expected between 2035 and 2050. It is expected that the greatest discrepancy between the IP and II3050 scenarios and modelling will be at the level of the larger - mostly industrial - existing and new customers. Therefore, the assumption is that consumption in 2050, particularly at the connector point level, has been underestimated. This underestimation has little effect with regard to the underlying LV and MV networks.

The strong growth in solar panels over the next decade, combined with a projected increase in curtailment between 2035 and 2050, means that generation peaks will not increase further, or may even decrease, between 2035 and 2050. Figure 50 even shows a declining peak load for generation peaks between 2035 and 2050 in the Decentral Initiatives and National Leadership scenarios. This is a consequence of the increase in curtailment from a maximum of 30% in 2035 for small-scale rooftop solar systems to 60% in 2050. In respect of large-scale solar systems, curtailment increases from a maximum of 50% in 2035 to 60% in 2050. An increase in curtailment – and the net neutral or positive grid impact – is possible as installations are replaced within a period of 25 years. The current service life for inverters and panels is approximately 25 years. More panels are expected to be installed between 2035 and 2050, but in combination with smaller inverters. The smaller inverters reduce the capacity for feeding into the grid. As a result, the capacity requirement does not increase further and may even decrease after 2035, in places where generation is and remains the biggest bottleneck. Curtailment should be implemented to the maximum extent at an earlier point in time to avoid unnecessary investments. These are investments that will be needed in 2035 but no longer needed in 2050.

The upcoming investment plan (2024 IP) focuses on the extent of the problem regarding the ability to execute the work for the next decade. Transmission scarcity is likely to persist in the coming years, so some of the necessary investments will not be realised until after 2035. Exactly which investments must be a societal choice for which the frameworks are set in the joint process of programming and prioritisation; see Figure 51. In the investment plans, consideration has been given to the prioritisation of projects, based on the established provincial Multi-year Programmes for Infrastructure and Energy and Climate.

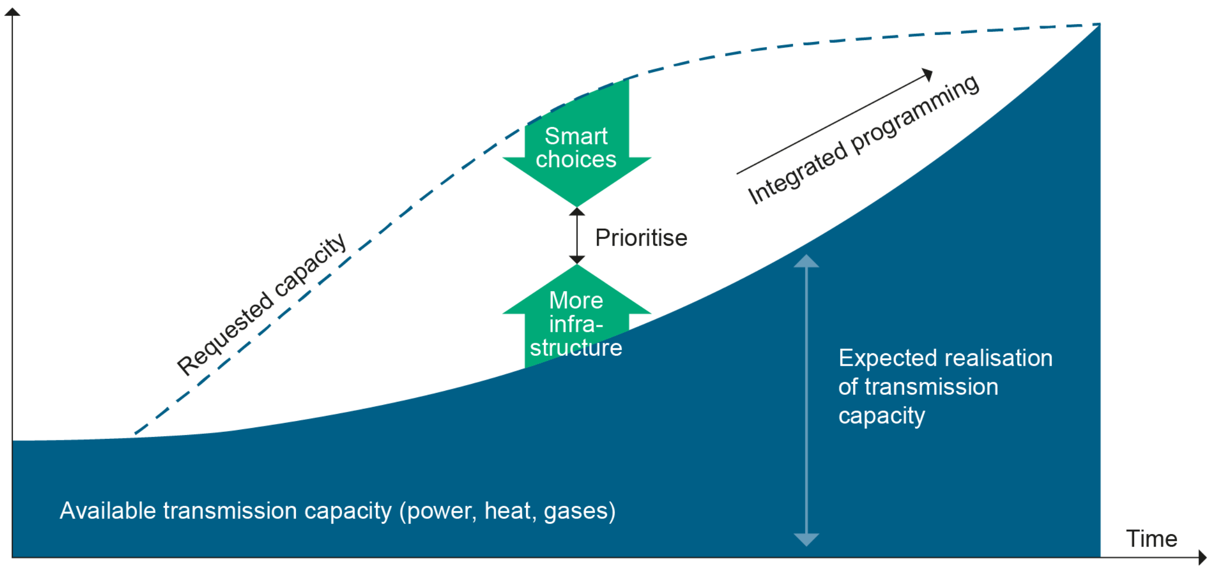

Figure 51 *Illustration of the programming and prioritisation process in the context of transport scarcity.*

7.5.2 Underlying grid

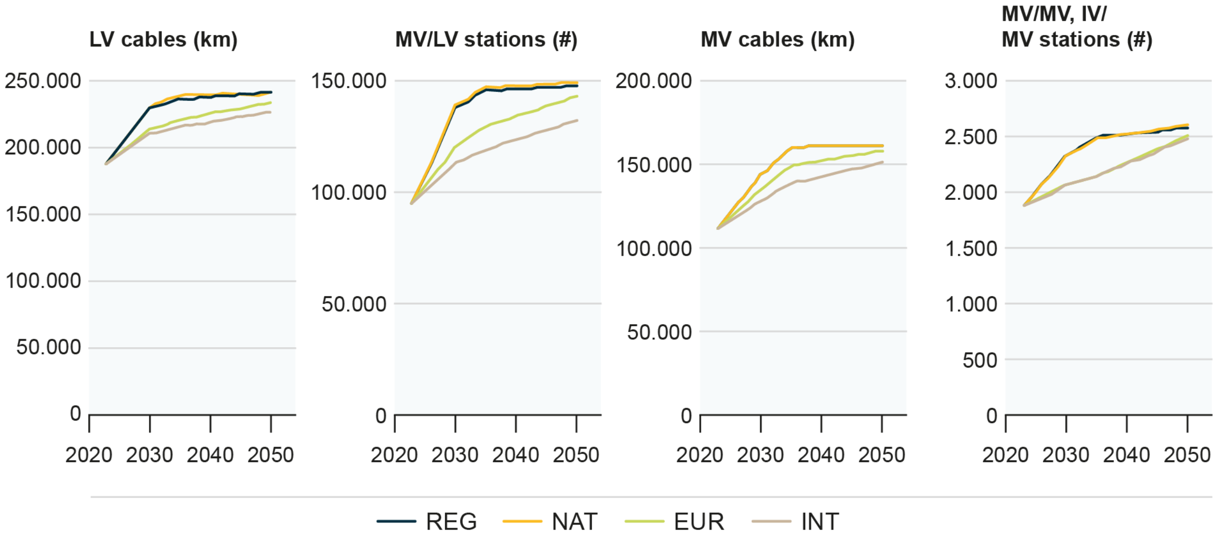

Figure 52 *Development path for LV cables, MV/LV stations, MV cables and IV/MV and MV/MV stations.*

Figure 52 outlines the development path for the underlying grid in the period to 2050. This is based on the three scenarios for the 2024 IP (IA, CA and ND) and the four scenarios for II3050-2 for 2050 (REG/NAT/EUR/INT). The paths for the LV cables, MV/LV stations, MV cables and IV/MV and MV/MV stations are displayed. The graphs show that most of the capacity expansions must be realised in the next ten years. This is most extreme for the lowest voltage levels (LV cables, MV/LV stations and MV cables). This is the period when the greatest growth in generation and energy demand electrification is expected, due to the new, more ambitious CO_2 reduction target in 2030. The Decentral Initiatives and National Leadership scenarios contain the most sustainable generation. Both scenarios also include the same amount of small-scale rooftop solar power. Because the bottlenecks in these scenarios are primarily caused by generation, the development paths are very similar. In the case of both development paths, there is also limited growth after 2035 because generation peaks do not increase further between 2035 and 2050 due to increasing curtailment.

In all scenarios, a large portion of the LV grid needs to be upgraded, and grid stations must be added. Upgrading the LV cables requires excavation work in streets and the addition of the MV/LV stations means space above ground must be made available. Network operators will have to carry out work in almost every neighbourhood. A ‘district-based approach’ is often used for this. If the network operator applies the district-based approach when starting the work, the entire grid in that district will be prepared for the climate-neutral final picture in 2050. If the final picture is not yet clear, a future-proof approach is chosen that is sufficient in all scenarios. To avoid unnecessary investments, it is important that choices be finalised as soon as possible. This includes, for example, concretely translating the Transition Vision Statement for Heating, (the Heating Programme, due to the introduction of the Dutch Environment and Planning Act) into a District Implementation Plan. This should include reserving the necessary space for grid infrastructure so that the network operator can start working without delay to facilitate the energy transition in a timely manner. Immediately future-proofing neighbourhoods moves part of the work package forward in time.

Like the substations, the execution problem also has an impact on the underlying grid, due to the scarcity of staff and equipment. As a result, some bottlenecks will not be resolved in a timely manner. This is especially true of the scenarios with a high sustainable generation component, where the growth curve is at its steepest over the next decade. This why prioritisation based on societal value is important. The distinction between generation and consumption bottlenecks is also relevant in this context. A generation bottleneck in the LV grid is often the first point where voltage problems arise, causing inverters to automatically shut down at times when there is excessive generation. This shut-down prevents capacity bottlenecks that can lead to a power outage throughout the district. The consequences of consumption bottlenecks are more significant. A power outage in the district is guaranteed when a consumption overload arises. This explains why these bottlenecks are often given priority over generation bottlenecks.

7.6 Limitation and discussion

Two different approaches to modelling the grid impact were used in drawing up the development path. Up to 2035, the results are consistent with the internal calculations for the upcoming investment plans (2024 IP). The network operators applied the national scenarios in their own internal modelling tools for this. In II3050-2, a uniform nationwide 'regionalisation' (regional breakdown) and identical profiles per driver (technology) were used for all network operators. In some cases, this leads to a lower load expectation in 2050. The expectation is that the greatest discrepancy between the IP and II3050 calculations is due to the developments and profiles of the larger - mostly industrial - existing and new customers. As a result, the 2050 results for the connector points are lower, as described in Section 7.5.1. Because of this, the recommended course of action in the event of a follow-up study is to consider all horizon years using the same methodology.

The regionalisation of large-scale rooftop solar systems reflects the regional distribution of the RES 1.0 plans[34]. As a result of the methodology chosen, large-scale rooftop solar systems have the same distribution as large-scale solar farms. In retrospect, it makes more sense to regionalise rooftop solar systems for buildings based on the suitable roof area with solar power potential. Relative to the current distribution, rural areas would then have less rooftop solar power and urban areas would have more. This reduces the differences between these areas in consumption and generation bottlenecks.

The determination of the grid impact does not take into account possible congestion management interventions as a result of transport constraints. This is a deficiency when identifying the grid load, because it is already an important component of the interaction between the network operator and customers, and its importance will increase in the future. Congestion management and other alternative contract forms offered by network operators for smarter use of scarce grid capacity are essential when it comes to dealing with the issue of execution. This is because they can potentially lead to a permanent change in customer behaviour. Calculations are made mainly based on network operator's current methodology and role, the ‘energy for everyone, at all times' approach. In doing so, flexible contracts and control resulting from, for example, Programming & Prioritisation, are not brought into play, even though this is already part of the current landscape. Unfortunately, it was not yet possible to develop a conclusive calculation method that adequately integrates complexity and local customisation for II3050-2.

The deployment of flexible batteries as an alternative to upgrading the grid becomes attractive when the costs are lower than grid investments. At present, from a societal perspective, upgrading the grid is more cost-effective than installing batteries[35]. In the first edition of II3050, batteries as an alternative to upgrading the grid were modelled in the form of ‘system-level batteries’. However, based on the current state of knowledge, this type of flexibility is no longer included in II3050-2. Even so, batteries are still expected to be used as a bridging measure when upgrading the grid to ensure the feasibility of the energy transition.

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34 See also the regionalisation described in the II3050 Scenario Report (28 March 2023), 'The Energy System of the Future: the II3050 Scenarios'.

35 See also: CE Delft, ‘Beleid grootschalige batterijsystemen en netcongestie’ [Policy on large-scale battery systems and grid congestion], and: CE Delft, 'beleid voor grootschalige batterijsystemen en afnamenetcongestie' [policy for large-scale battery systems and consumption congestion]

Chapter 8

Impact on the 2050 regional gas infrastructure

8.1 Conclusions and recommendations

Conclusions

- In all scenarios, a significant proportion of the gas network becomes obsolete: between 20% and 65% of the LP (low pressure) mains network will no longer be needed. The removal of this part of the gas network represents a large work package, which will demand much of the available implementation capacity.
  In the International Trade scenario, most of the LP mains network (80%) remains in use, but must be largely converted to hydrogen.

- The extent to which areas are disconnected from the gas network in clusters varies significantly between the scenarios. If this is not done, almost none of the network can be removed despite a large decrease in the number of connections, meaning that a large part of the network will still need to be maintained for a limited number of connections. This is shown in the National Leadership scenario, where half of the gas network still has to be maintained for only 15% of the homes.

- The green gas production in the scenarios is spread widely across the country and is often not in the same location as the demand for gas. Without additional measures in the gas networks, between 200 and 250 boosters will be needed in order to use all the green gas. The number of boosters can be significantly reduced by matching green gas production with methane demand, interlinking separate gas networks, using green gas collector pipelines and clustering production.

- Outside the winter months, there is a surplus of green gas in most areas. However, in the winter months, there is a peak in demand. This means that storage is required. If storage takes place on a national scale, boosting to the high-pressure gas grid (HPGG) will be required. This raises questions about the required gas quality, as different requirements apply to the green gas fed into the distribution networks compared with the gas quality that is permitted for underground storage, in relation to the permissible oxygen and moisture content, for example.

- Converting parts of the natural gas network to hydrogen is possible, but this requires customisation for each situation. It is important to make choices about which sectors will transition from methane to hydrogen and where, because ideally both gases would use the existing gas network. In general, having a parallel local infrastructure of methane and hydrogen networks in the final situation is not desirable due to the added complexity, the safety aspects, the need for additional investment and the greater use of implementation capacity and space.

- Converting gas networks to hydrogen requires a great deal of coordination among all the stakeholders, which – combined with the actual implementation – results in long lead times. Innovations in licence issuing and engineering could significantly speed up the long completion time associated with conversion projects. In addition, (temporary) parallel infrastructure may be needed to transport both hydrogen and green gas when conversion cannot take place in one operation.

Recommendations

1. When homes are disconnected from the gas network, it is important that this work is done to the greatest possible extent in clusters, both in terms of location and timing. This leads to economies of scale in the work flows: when a complete district is disconnected from the gas network in one operation, the network operator only has to do the excavation work and make changes to the gas network once. Clustering therefore leads to economies of scale, thereby reducing the cost per connection and the required manpower. So it is important that government authorities plan the work in clusters wherever possible.

2. Policies will need to be formulated regarding the approach to unused gas pipelines. Removing them immediately could result in a high workload for the network operator. Spreading this work over several years, and scheduling it as much as possible at convenient times, will reduce the workload. Netbeheer Nederland's Gas Network Removal Policy working group is formulating policy for this purpose.

3. Additional research needs to be done regarding green gas storage. What is the best solution: local, regional or national storage? This directly affects how much green gas must be compressed and to what extent. Areas of concern in this context include the gas quality, such as oxygen, carbon dioxide and moisture content, especially in relation to the national gas storage facilities.

4. Consideration must be given to this in short order and choices made regarding the ‘distribution conundrum’. This issue requires much thought about which areas and sectors will transition to hydrogen at what point, or whether another energy carrier is preferable. In the start-up phase, it will probably be necessary to build a dual gas infrastructure in some areas, but from the point of view of implementation capacity, complexity and safety, using only one type of gas per area where possible is clearly preferable. This issue requires firm guidance from the government in order to outline the right frameworks and make the right choices.

5. Any transition to hydrogen that takes place will require significant coordination between the different stakeholders: contractors, customers, network operators, municipalities, etc. That coordination should preferably be handled by a body with decision-making authority that can consider all the interests.

8.2 Current regional network infrastructure

The regional gas infrastructure mainly distributes gas from central points - where the gas is brought in from the national transmission network - to the end customers. Natural gas is used in the Netherlands for heating, among other purposes. As a result, consumption and peak demand in the winter are many times higher than in the summer. The regional gas infrastructure is dimensioned to supply gas for the level of heat demand at -13°C.

The regional gas networks are made up of various types of stations and pipelines. A gas receiving station (GRS) is the transfer point between the national network operator and the regional network operator. Behind each gas receiving station is a distribution network that is largely laid out in a finely meshed structure. This means that many networks are interconnected, and a network can also be fed from multiple gas receiving stations. The total area covered by an interlinked network like this is called a linked GRS area. In total, there are roughly 275 linked GRS areas in the Netherlands.

In a gas receiving station, the pressure is reduced to 8 bars for feeding into the high-pressure (HP) distribution networks of the regional network operators. The HP distribution networks are at a pressure of between 200 mbars and 8 bars. The high-pressure pipelines are connected directly to supply stations for major customers or to district stations, where the pressure is further reduced to between 100 and 30 mbars: this is the low-pressure network (LP network), to which homes are connected for example. Figure 53 presents a visualisation of the networks.

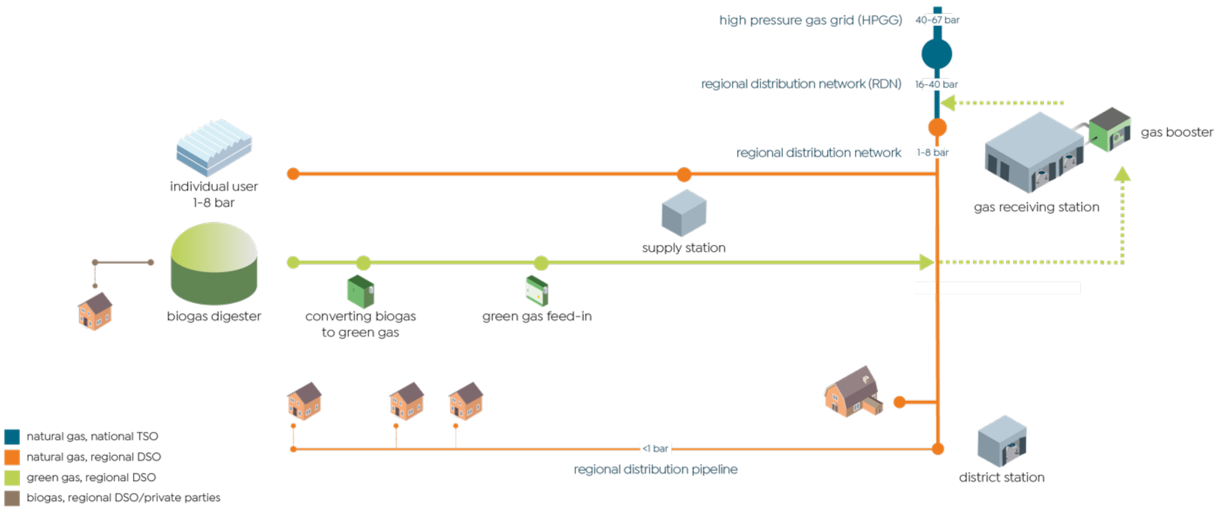

Figure 53: *Visualisation of the topology of the regional gas networks.*

The district stations are often located in or on the edge of a residential area. The built environment is connected to these district and supply stations via low-pressure networks. The pipelines in this part of the distribution network are called main pipelines and connection pipelines. The main pipelines run down the street past the homes. The connection pipelines distribute gas to the homes, so they branch off the main pipeline. There are also large connections to specific supply stations, such as those for greenhouse horticulture businesses. An average town with a population of 100,000 residents has about three gas receiving stations, and about 300 district stations (one district station for every 250 to 500 homes). An area is typically supplied by multiple district stations for reasons of security of supply.

8.2.1 Regional feed-in of green gas

In the current gas system, in addition to centralised distribution of natural gas at various points in the network, green gas is also fed in regionally. Green gas is produced locally by anaerobic digestion, which in most cases is fed into the HP distribution grid, or by gasification, which is usually fed into the HPGG. The green gas is produced from organic waste, manure, sludge and biomass, etc. Green gas is upgraded biogas and complies with the gas quality stipulated in the Ministerial Regulation on Gas Quality, which natural gas must also comply with.

The current share of green gas in the Netherlands is still modest. In 2022, it amounted to about 0.23 bcm[36] of the total 31 bcm of gas consumed[37]. In the future, this share may grow significantly due to the target of producing 2 bcm of green gas by 2030, and the expected decrease in methane demand. A large increase in the share of green gas does however require some adjustments to the gas networks. Green gas production is fairly constant

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[36] Gasunie, 2023. Share of green gas increases in 2022, but not as fast as is necessary. See gasunie.nl

[37] CBS, 2023. Gasverbruik in Nederland in 2022 laagste in 50 jaar [Gas consumption in the Netherlands in 2022 at the lowest level in 50 years]. See cbs.nl

throughout the year. In contrast, national gas demand is lower in the summer than in the winter, leading to an imbalance across the seasons. In addition, imbalances can also occur based on location: in linked GRS areas, both shortages and surpluses can arise due to green gas demand and production. Additional measures are therefore required to match supply and demand effectively. The additional measures are described in 8.4.2.

8.2.2 Hydrogen in the distribution networks

In a number of scenarios, gas networks are converted for hydrogen distribution. The modifications for this are detailed in 8.4. It is also possible that power-to-gas installations will be developed in decentralised networks that will be connected to regional gas networks. In the case of decentralised electrolysis, gas compression needs to be facilitated in part of the distribution network, so that the gas can be transported to higher pressure levels.

The simplest way to use hydrogen in the distribution networks is to blend hydrogen and methane. A combination of the two gases then flows through the gas network. However, this does lead to variations in the gas quality. That poses a problem for measurements, operations and safety in the network. In addition, all the connected gas-burning appliances must be able to function with a blend of the two gases. Unless the share of hydrogen is limited, many changes will still need to be made to the gas network and at user locations[38].

Converting part of the gas network to hydrogen does mean that all connections in that part of the gas grid must be converted for hydrogen. An alternative is to split the gas network into multiple parts: one part with hydrogen and one part with methane. These networks must also be fed separately from a higher-level hydrogen and methane network. In lower-level gas networks, operating separate gas networks for methane and hydrogen side by side is complex. With repurposing of the current natural gas network as the point of departure, converting the pipelines and customers – without long supply interruptions and without having to making new supply pipelines available – is a major challenge. This also makes a significant extra claim on investment, implementation capacity, safety and space utilisation. In many cases, many additional pipelines will have to be laid to make this possible. It is therefore desirable in a final situation to separate gas networks for hydrogen and methane as much as possible locally and regionally, so that an area can be supplied with only one type of gas.

8.3 Changes in supply and demand in the regional gas network

This section describes the effects of the scenarios on the regional infrastructure for the gas networks.

8.3.1. Heating transition in the built environment

The impact of the heating transition on the gas network is based on the spread of future household heating solutions across neighbourhoods, according to the four scenarios. A distinction is made between different types of heating solutions: all-electric heat pumps, district heating, central heating boilers, hybrid heat pumps and other heating solutions.

Heating solution projections for the four scenarios are shown in Figure 54. Because the Decentral Initiatives and National Leadership scenarios rely primarily on decentralised renewable energy generation, all-electric heat

[38] Kiwa, 2020. De impact van het bijmengen van waterstof op het gasdistributienet en de gebruiksapparatuur [The impact of blending in hydrogen on the gas distribution network and on gas-burning appliances]. See netbeheernederland.nl

pumps play an important role in heating in these scenarios. Because there is more of a focus on molecules in the European Integration and International Trade scenarios,

heating based on gas is a strong element there. This leads to differences per scenario in the number of homes still connected to the gas supply in 2050. This ranges between 15% in the National Leadership scenario and 60% in the International Trade scenario.

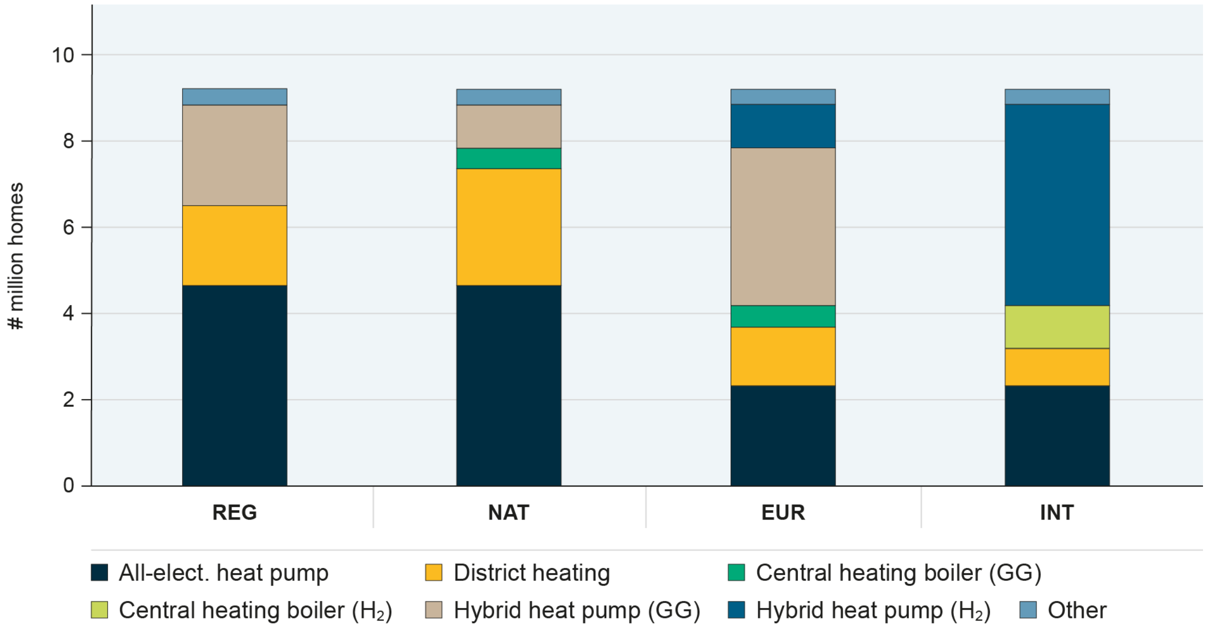

Figure 54: *Numbers for the heating solutions in households in 2050 per II3050-2 scenario. 'Other' consists of wood pellet stoves and electric central heating boilers.*

8.3.3 Use of green gas in the gas network

In all four scenarios, green gas is used in 2050. However, the differences are significant. The production of green gas and feed-in into the networks depend strongly on the scenario. In the European Integration scenario in particular, a lot of green gas is fed in regionally. There are also significant differences in the feed-in location: more green gas is generally fed in in rural areas than in the more urban areas.

The differences in the consumption of methane are also significant: for example, in the European Integration scenario more than 4 billion m³ of gas are still transported, compared to a mere 170 million m³ in the International Trade scenario. Figure 55 presents an overview of the methane demand per scenario, based solely on the methane demand fed in through the regional network operators. In all scenarios, the built environment is the main consumer of methane from the regional network operators. In all scenarios except International Trade, there are still homes that need methane. The methane is mainly used for hybrid heat pumps. In addition, there are still homes with methane-fired central heating boilers in the National Leadership and European Integration scenarios. In the International Trade scenario, the methane is used to supply extra heat to the heat grids at peak times. In addition to the built environment, industry is a major consumer of methane in the European Integration scenario.

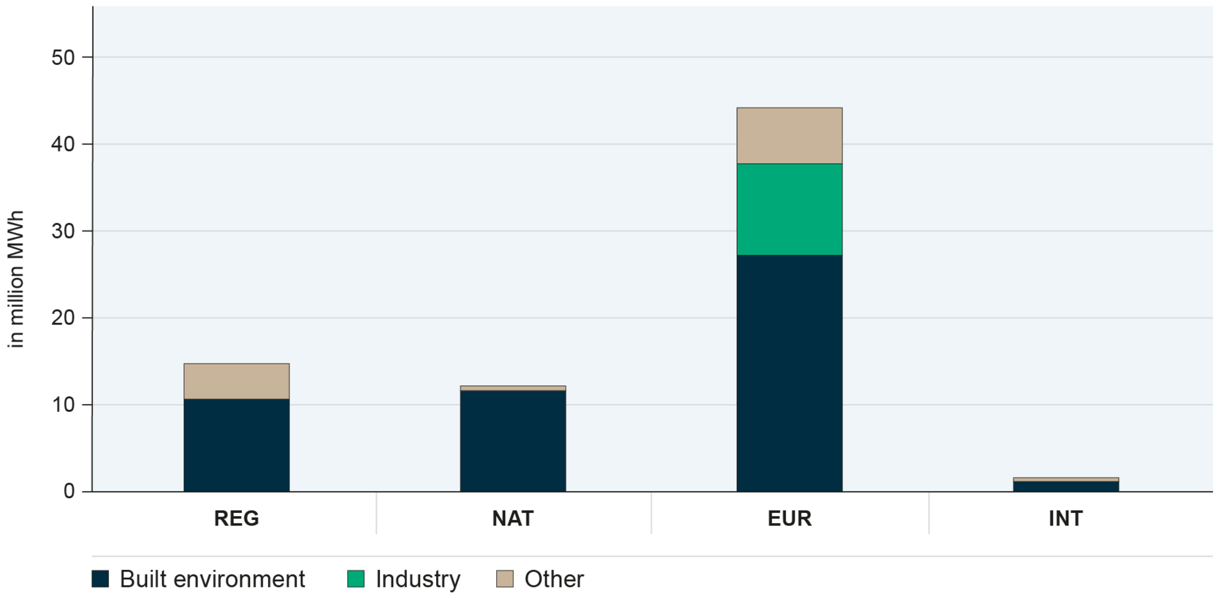

Figure 55: *Demand for methane supplied by the regional network operators in 2050, split by category*

8.3.4 Use of hydrogen gas in the gas network

Hydrogen is used in 2050 in all scenarios. In the Decentral Initiatives scenario, it is mainly used for transport and electricity production, as shown in Figure 56. The National Leadership scenario also includes an element of demand from industry, as opposed to the European Integration scenario where there is demand from the built environment. Hydrogen demand is by far the highest in the International Trade scenario, with hydrogen used in many different sectors. Much of the energy demand from the built environment is met by hydrogen in this scenario.

The mobility sector requires hydrogen in all scenarios, mainly for heavy goods transport and long-distance transport. In the International Trade scenario, there is significantly more demand for hydrogen in the regional networks, mainly because some cars and buses also switch to hydrogen, and hydrogen also has a larger share in goods transport. The high quality needed for hydrogen in mobility is a concern. Because of the quality requirements, it may be difficult to supply hydrogen to fuel stations for road traffic from the regional gas networks. A possible alternative would be to use tube trailers.

Regional industry requires a relatively limited amount of hydrogen in the distribution networks, but this segment is still a logical starting point for converting the gas network to hydrogen. These are large connections in the distribution networks, which are a natural starting point for converting the local gas network to hydrogen. This is only relevant in the National Leadership and International Trade scenarios.

In the scenarios that include hydrogen in the built environment, widespread use of hybrid heat pumps is expected. There are also hydrogen central heating boilers in the International Trade scenario. In the European Integration scenario both hydrogen and methane are used, leading to a tricky ‘distribution puzzle’: i.e. deciding which neighbourhoods are supplied with which type of gas. Transitioning homes from methane to hydrogen means that conversion work must be done. This is logistically complicated because the work has to be done all at once in a short period of time. More information on this is provided in Section 8.4.3.

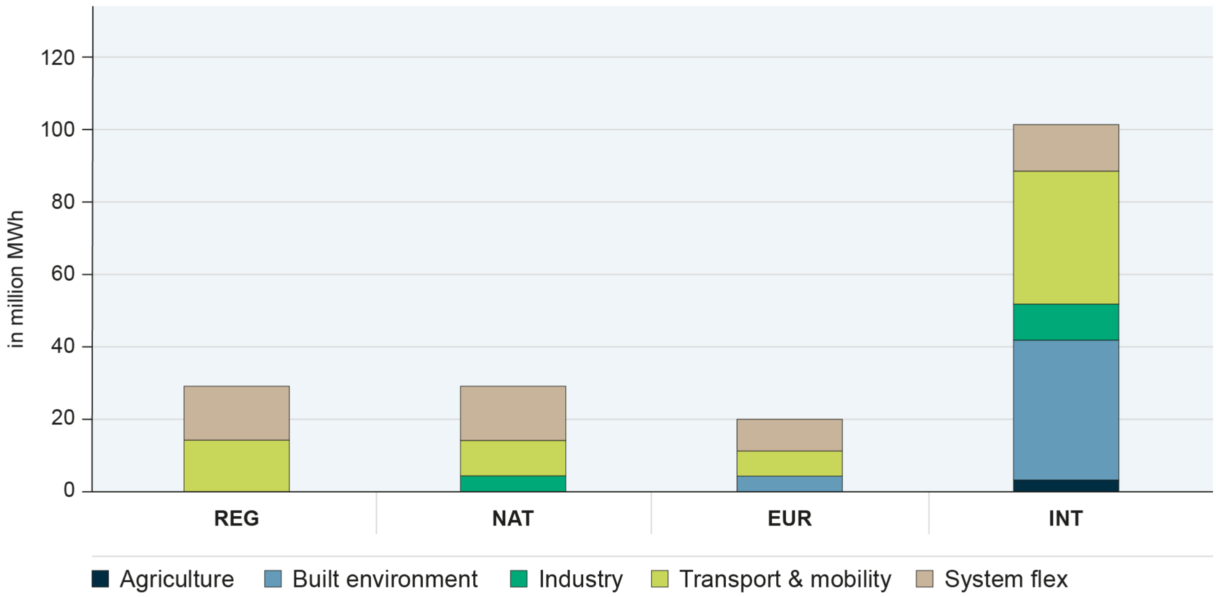

Figure 56: *Demand for hydrogen in the distribution networks, split by category*

8.4 Infrastructure developments moving towards 2050

8.4.1 Removal of the gas network

In the future, many existing homes will switch from methane to other heating technologies. The number of households varies depending on the scenario. When an entire district switches to, for instance, district heating or all-electric heat pumps, it becomes a gas-free district. In that case, part of the existing gas network will no longer be used.

The question as to whether this unused part of the gas network can be reused for other functions, or whether it has to be removed, is still open. Furthermore, if it is removed, the next question is whether that needs to be done immediately after the last user has been disconnected. Immediate removal of the gas grid has a much greater impact on the regional network operator's operations than combining the removal work with other work for which soil needs to be excavated anyway. Based on current regulations, immediate removal is still necessary in most cases. With that in mind, this report explicitly assumes immediate removal in order to determine the impact on the infrastructure.

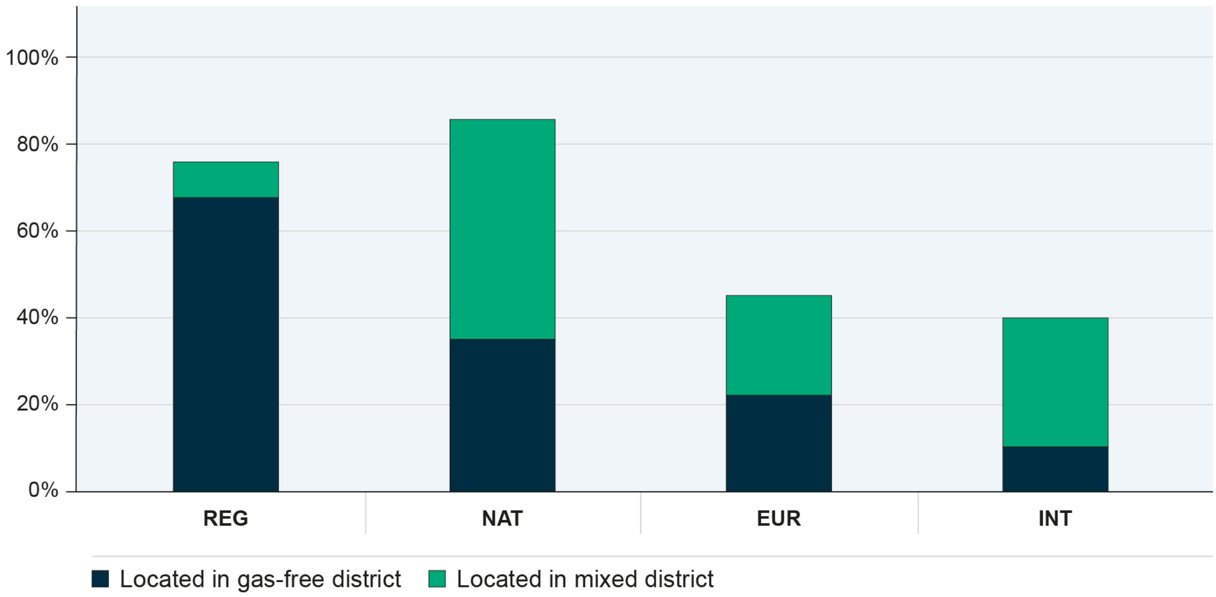

Figure 57: *Percentage of gas-free homes in a district that is fully or partially gas-free.*

Figure 57 shows wide variations in the degree of clustering of gas-free homes. In the Decentral Initiatives scenario, almost all gas-free homes are in a gas-free district, as opposed to the International Trade scenario where a small percentage of gas-free homes are in a gas-free district. There is no linear relationship between the number of gas disconnections and the part of the gas network that is no longer used and therefore potentially removable. If the number of gas connections were reduced by half, only about 15% of the LP network could be removed. It is only possible to remove the entire gas network if the district is completely gas-free. The exact relationship between the number of gas disconnections and the amount of the LP gas mains network that can be removed varies greatly depending on the specific topology of the network.

Figure 58 shows the proportion of the LP gas mains network that can be removed given the number of gas disconnections per district. For comparison purposes, the number of gas-free homes per scenario is also shown in percentage terms. The impact of clustering on the unused gas network, and therefore the part of the gas grid that can be removed, is clearly presented here. In the National Leadership scenario, there is much less clustering of gas-free homes, so also a relatively much smaller proportion of the gas network that can be removed compared to the Decentral Initiatives scenario. The same effect can be seen between the European Integration and International Trade scenarios. The total amount of LP mains infrastructure to be removed is between 20% and 65% of the existing network.

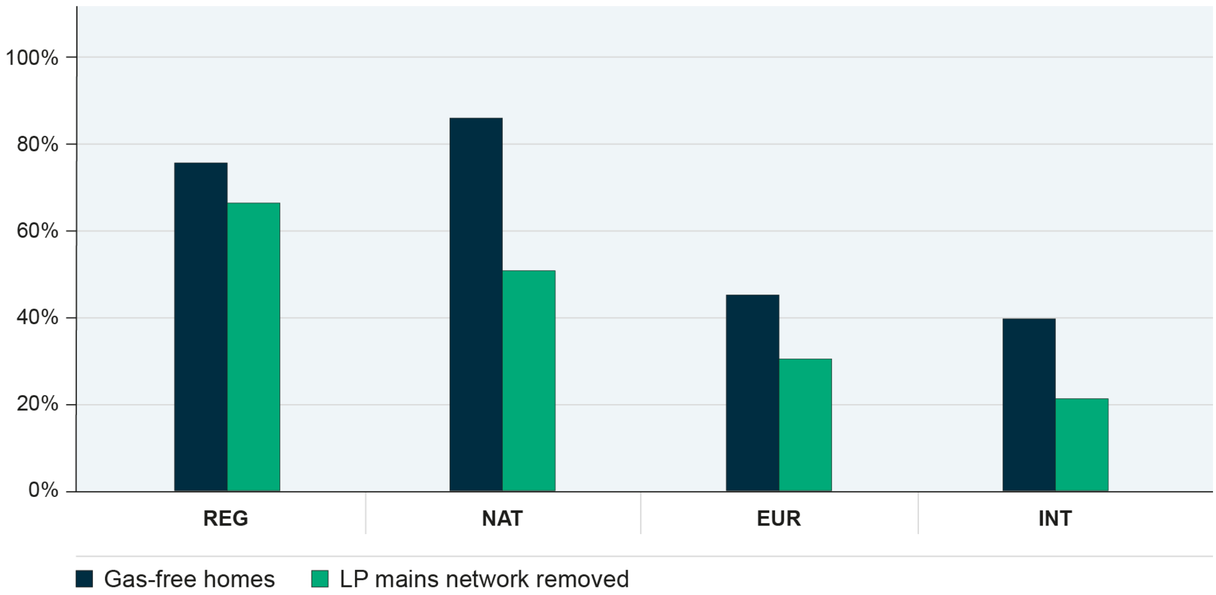

Figure 58: *Percentage of low-pressure network to be removed and corresponding proportion of households without a gas connection*

In addition to the removal of parts of the LP mains network, district stations can sometimes also be removed. Denser clustering of gas-free homes generally means that more district stations can be removed. A rough estimate of the number of district stations to be removed ranges from about 1,500 for the International Trade scenario to about 10,000 in the Decentral Initiatives scenario.

The percentage of high-pressure pipelines to be removed is lower than the percentage of low-pressure pipelines. The LP pipelines are mainly located in districts and can therefore be removed once a district becomes gas-free. HP pipelines on the other hand have a different function. The HP pipelines are used for transmission between districts[39]. That means many districts in the same region must become gas-free before any part of the HP pipelines can be removed. Removal of part of the HP pipelines may also affect the security of supply for the remaining customers in the area. Furthermore, large users, for example in business parks and small industrial businesses, are also connected directly to the HP distribution network. This part of the network can only be removed if all directly connected large users also switch to alternatives to their current gas connection. In the National Leadership scenario, most industrial users are expected to remain in the Netherlands and, as a consequence, most of the HP distribution network needs to remain intact for transmission. HP pipelines may also need to be added locally to facilitate network connections for green gas bottlenecks.

8.4.2 Making the gas network suitable for green gas

In the gas network, gas cannot be transported to higher pressure networks without modifications. If there is insufficient gas consumption locally, additional measures are needed to transmit green gas feed-in. This local overproduction of green gas can be dealt with in a number of ways:

- Network interconnections: expand the service area by connecting networks at the same pressure level or by using unused pipelines to centrally compress green gas feed-in.
- Increase the local gas demand or use surpluses locally in other ways.

[39] In practice, LP pipelines are sometimes also used for transmission between districts

- Concentration of green gas production: feeding higher production per location directly into higher pressure networks or connecting small production sites together via collector pipelines.
- Gas boosters: use compressors, boosters, to transfer the gas produced to a network at a higher pressure level.
- Gas storage: local, regional or national storage of green gas.

Network interconnections and increasing local gas demand may be effective local solutions for increasing gas consumption. This can help in specific cases when an area with a surplus of green gas is situated next to an area that has a large deficit. In the vast majority of the areas this is not the case and the adjacent areas also have a surplus in the summer. Feeding green gas directly into higher pressure networks prevents local surpluses, but is not always possible due to limited volumes or the distances to the higher pressure networks. In most cases, gas boosters are needed to feed green gas from the regional networks into the national networks. Local gas storage facilities are an alternative, but these facilities present major challenges in terms of expense and use of space. Because there is regularly a national surplus of green gas production outside the winter months, storage is necessary - either regionally or in the existing national storage facilities.

Green gas boosters

To put all the green gas to good use, green gas boosters are needed in many places. These are compressors that can transfer the gas produced from the distribution network to Gasunie's regional transport pipeline network. The choice of 'regionalisation' (regional breakdown) for green gas production leads a wide spread of production sites, requiring small boosters with a capacity of less than 1,000 m^3/hour in many areas. Denser clustering of green gas production can help reduce the number of boosters. Ideally, one would want to install fewer and larger boosters, for example, by concentrating feed-in locations, linking network areas together or linking production locations to a centrally located gas booster via a collector pipeline.

Another option is to install a booster only in areas with larger surpluses. To analyse this, we looked at a ‘threshold value’ for installing a green gas booster. A threshold value of 1,000 m^3 per hour indicates that a booster will be installed only if the surplus is at least 1,000 m^3 per hour in the summer. This therefore means that fewer boosters need to be installed, but also that green gas production in areas with a limited surplus cannot be transferred to higher pressure networks.

Figure 59 shows the relationship between the threshold for gas booster installation and the number of gas boosters that are installed. The assumption in this analysis is that a party feeding in green gas is able to feed in during a minimum of 8,000 hours per year. A relatively small threshold value of 1,000 m^3 per hour already has a large effect on the number of boosters to be installed. In the different scenarios, this results in a drop from about 200-250 boosters to 30-100 boosters.

The effect this threshold has on the amount of green gas that cannot be transmitted is shown in Figure 60. A threshold value of 1,000 m^3 per hour in the European Integration scenario has a limited effect in this respect: only 3% of green gas production cannot be transmitted. But in the other scenarios, this rises to between 13% and 28%, which means that a significant amount of green gas can no longer be transmitted. Because of the balance in the system, it is then necessary to either increase imports or decrease methane demand.

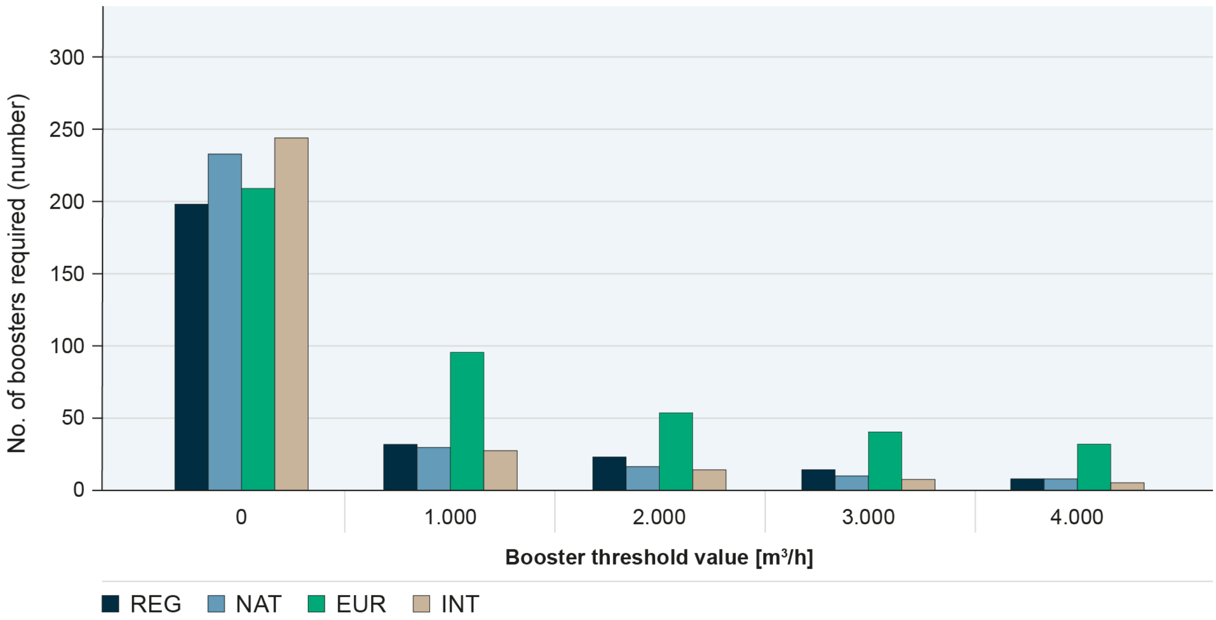

Figure 59: *Relationship between the threshold value for a booster and the number of boosters needed in the distribution networks.*

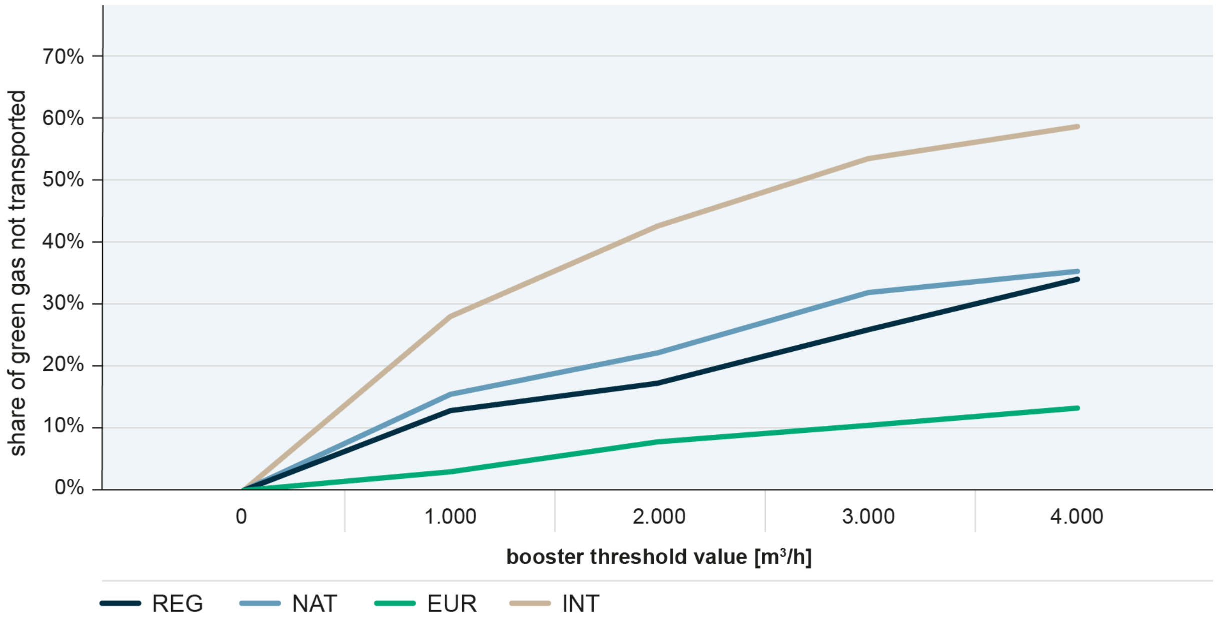

Figure 60: *Relationship between the threshold value for a booster and the proportion of green gas that is not transmitted in the distribution networks.*

In most cases, the gas is compressed to allow transfer to Gasunie's 40-bar regional gas network (see Chapter 6), which then creates a surplus in most of the 40-bar networks. Several dozen additional boosters to transfer gas from the regional network at 40 bars to the national network at 67 bars would then be needed. If possible, boosting the pressure from 8 bars to 67 bars directly may be desirable to avoid that extra intermediate step.

Storage

Green gas feed-in shows a flat profile throughout the year, whereas peak demand, for heating buildings, mainly occurs in the winter. This leads to a seasonal imbalance between the winter months and the other months. Storage is necessary to smooth out this imbalance. There are basically two solutions: regional gas storage or national gas storage. Regional storage facilities eliminate the need to transmit gas, but spatial incorporation and cost are major concerns. National storage facilities are probably cheaper, but require consideration of the gas quality - specifically, the oxygen concentration. Additional research into the seasonal green gas storage options is needed.

8.4.3 Making the gas network suitable for hydrogen

The way hydrogen behaves in the gas network differs from methane. The obvious differences are the much lower density (factor of nine), the lower energy density (factor of three) and different ignition limits. In practice, this has an effect on the end-user appliances, e.g. burners that need to be modified, and also on the potential flow rates in the networks. Both working groups formed by Netbeheer Nederland and broader research collectives such as Hydelta are investigating hydrogen transmission and distribution.

Suitability of the gas networks

Studies of the materials and components in the natural gas network have shown that the gas network is mostly suitable for transporting hydrogen. In fact, at the same pressure profile, the pipe capacity is about the same as for natural gas if the hydrogen can be made to flow through the pipes at three times the speed. In view of this, limited modifications are needed to convert the current gas networks to hydrogen networks. Modifications are also needed at the end-user point, such as replacement of the gas meter and the gas appliances.

In 2050, in the European Integration and International Trade scenarios, hydrogen delivers energy for part of the built environment and industrial users. In the first phase, the five major industry clusters are expected to transition to hydrogen in stages. Once the major clusters have transitioned, part of cluster 6 could also be switched to hydrogen. Then combinations can also be set up with the built environment or nearby mobility facilities. However, to get to that situation, a conversion involving a switch from natural gas to hydrogen must take place at some point. Studies investigating a conversion of this nature, e.g. Hydelta 2.0 work package 7, have led to the following findings:

- Conversion of the network involves many parties (network operators, customers, suppliers, etc.). Completing a conversion project successfully requires clear responsibilities and information transfer between all those stakeholders. Ideally, the government needs to define the framework conditions and appoint an implementing agency to coordinate the process.

- The gas network must be converted to hydrogen one sub-network at a time, and that process from the planning phase to the implementation phase can take several years for each sub-network. Things can be speeded up by using gas appliances that are suitable for both methane and hydrogen at end-user points. In addition, the licence issuing process for installing hydrogen stations in particular must be speeded up.

- The existing methane network can be used for hydrogen only if end users do not also want to keep a methane connection, i.e. a dual connection. Otherwise, a separate hydrogen network must be put in place. Overall, a dual network is probably not the preferred option due to considerations of practical feasibility and cost-effectiveness. In the transition period, a relatively large amount of new network construction will still be needed anyway, as the methane infrastructure is not yet available.

8.5 Development path

8.5.1 Removal of the gas network

In all scenarios, the gas network is used less, and more and more gas pipelines are left unused. It is not yet completely clear what will happen to these gas pipelines. This analysis is based on the principle that there is a statutory obligation to remove the unused gas pipelines. As mentioned earlier, this amounts to between 21% and 66% of the total LP network. This is a very significant amount of work, so it is important to know exactly when this work package needs to be done. Table 11 shows the average annual removal percentage of the LP mains network up to 2040, and after 2040. In the National Leadership and European Integration scenarios, the rate of removal before and after 2040 is reasonably similar. In the Decentral Initiatives scenario, the removal rate is much higher after 2040. In fact, many districts will be gas-free by then, in which case the LP mains network for the entire district can be removed. In the International Trade scenario, in contrast, the rate of removal is much slower because few additional gas-free districts will be added between 2040 and 2050. In all scenarios, a significant portion of the LP mains network must be removed, leading to a large work package.

Table 11: *Average annual proportion of the LP mains network to be removed up to 2040, and between 2040 and 2050.*

Scenario	Average per year up to 2040	Average per year between 2040 and 2050
Decentral Initiatives	2.1%	3.0%
National leadership	1.9%	1.8%
European integration	1.2%	1.0%
International trade	1.1%	0.3%

8.5.2 Development in the supply of green gas

Green gas production rises sharply in all scenarios in the period to 2050. At the same time, the total methane demand falls sharply. This causes a tipping point in the options for immediately using the green gas production at the local level. This tipping point already occurs before 2040 in many interconnected GRS areas, where the growth of green gas production exceeds the remaining gas demand in the summer months. Green gas boosters are required in these areas. Table 12 shows how many green gas boosters are needed in the period to 2040, and in the period from 2040 to 2050. This is based on the assumption of no threshold value for booster capacity. If a threshold value is applied (e.g. 1,000 m^3/hour), significantly fewer boosters are needed.

Table 12: *Average number of boosters per year up to 2040, and between 2040 and 2050.*

Scenario	Average per year up to 2040	Average per year between 2040 and 2050
Decentral Initiatives	10.1	2.8
National leadership	8.6	8.7
European integration	10.7	2.7
International trade	8.7	9.6

In respect of green gas boosters, the number of boosters to be installed is clearly skewed towards the period to 2040 in the case of the Decentral Initiatives and European Integration scenarios. This number is significantly less in the period after 2040. This does not apply to the National Leadership and International Trade scenarios, which show a more even trend through to 2050. Green gas storage capacity to accommodate the seasonal imbalance must be put in place in parallel with installing boosters.

8.5.3 The hydrogen and methane distribution puzzle

To avoid the need for duplicate gas networks everywhere, the preferred option is to use one type of gas per area as much as possible. This maximises the use (or repurposing) of the existing infrastructure for green gas and hydrogen distribution. It also means that the current natural gas network must be split regionally into separate networks for hydrogen and for green gas. A number of considerations come into play when splitting up the natural gas network. The choices made by one customer obviously affect other customers in the same area. To avoid duplicate gas infrastructure, customers who are on the same gas pipeline must use the same type of gas. This also applies to parties that feed in green gas. Green gas feed-in requires the presence of a local methane network. Converting from methane to hydrogen takes time because of possible modifications to the network and at the customer's premises. To avoid a situation where the gas infrastructure is out of service for a long time, the conversion work needs to be carried out as a start-to-finish project in small areas.

Investments are often planned years in advance and major changes are needed. This means that the distribution puzzle for other areas needs to be resolved very quickly when the hydrogen roll-out starts. With that objective in mind, consideration must be given now already to deciding which regions will use that hydrogen. This requires the formulation of new frameworks and coordination at the national level. Otherwise, there is a likelihood of fragmented hydrogen areas in sub-optimal locations. This remains a tricky puzzle at the moment because it is not yet clear what the cost of hydrogen and green gas will be and how much of it will be available.

8.5.4 Development of a regional infrastructure for hydrogen

How the regional hydrogen infrastructure will develop depends strongly on how the distribution puzzle is resolved. That must clarify how the regional network will be converted to hydrogen and for which pipelines. This decision is closely linked to the roll-out of the national hydrogen network. When a national network pipeline is converted to hydrogen, the underlying regional networks will also have to be converted to hydrogen, or switched over to another methane pipeline. Either that, or temporary duplicate infrastructure will be needed for gas and hydrogen. The appendices to this outlook contain the results of a number of studies conducted by the network operators. To gain hands-on experience with converting to hydrogen, pilot projects are being carried out by the regional network operators in cooperation with sectoral partners in Uithoorn, Lochem, Wagenborgen and other areas.

8.6 Uncertainties

The following developments are uncertain and have an impact on the regional gas infrastructure that have not been given consideration within the frameworks of the scenarios analysed here.

Dispersal or clustering in the production of sustainable gas
The regionalisation of green gas for the regional network operators is characterised by extensive spread and this has a direct impact on the number of boosters required. If green gas production is more concentrated in practice, fewer boosters will be needed and direct feed-in to the national grid could even be considered.
The regionalisation of hydrogen is very uncertain because it depends on the availability of the national hydrogen network, choices in other sectors and the feasibility of converting an area entirely to hydrogen. Clustered use and/or production of hydrogen versus widely dispersed production will have less impact on the regional gas infrastructure.

Hydrogen in regional networks
The role of hydrogen in the regional networks is uncertain and varies widely between the scenarios. For example, whereas in two scenarios there is no role for hydrogen in the built environment, in the International Trade scenario most of the residential buildings have a hydrogen connection. Because this infrastructure needs to be constructed in parallel with the phase-out of methane demand, it is very important to clarify as early as possible whether areas will be supplied with hydrogen and, if so, which areas. That will ensure adequate time for converting the networks. It is important to make choices, both by sector and geographically. Regional industry also has a requirement for hydrogen in the International Trade scenario. This can be supplied through separate pipelines, through pipelines shared with housing developments that use hydrogen, or directly from the national hydrogen network. These options vary widely in terms of complexity and the challenge they represent for the regional network operators.

Additional modifications to regional gas networks for hydrogen
In addition to the adjustments mentioned above, other changes to the regional gas networks may also be needed. These are not further quantified at this point - the degree of uncertainty is still too high. The most important changes are:

- Possible extensions to the network length that may be needed during the transition phase (2030 to 2050) to accommodate both green gas and hydrogen - separation of sub-networks, and building adequate redundancy into sub-networks.

- Extensions to the network length that may be needed in order to feed in hydrogen from regional power-to-gas installations - at higher pressures, for example, with interconnections to the national transmission infrastructure.

- The costs associated with enabling two-way traffic in regional hydrogen networks (hydrogen booster stations), perhaps necessary in the case of regional power-to-gas.
- Possible additional connections for industry, hydrogen fuelling stations for mobility, shipping, etc.

As the prospects for regional hydrogen networks become more concrete, it is recommended that the above developments be further explored.

Removal of gas pipelines

This analysis assumes the removal of gas assets as soon as they are no longer in use. The extent to which pipelines can be removed depends very much on the extent to which gas-free consumers are clustered. As a result, the extent of the low-pressure gas network that can be removed in each region is highly uncertain. Netbeheer Nederland is currently drafting the policy for this: ‘Verwijderingsbeleid voor hoofdnetten gas’ [Removal policy for the main gas networks]. This clarifies what should or could happen to the main gas networks as more and more gas connections are phased out due to the energy transition. Obviously, this takes into account both current and future laws and regulations. The removal policy can have substantial consequences for the operational work packages.

Chapter 9

Impact on other infrastructures

9.1 Conclusions

Infrastructure for CO_2

- In the II3050-2 scenarios, transmission by pipeline to one or more storage facilities in the North Sea is one of the possible solutions for reducing CO_2 emissions in the Netherlands to less than 10 Mtons per year by 2050.

- A network of pipelines between industrial clusters for the transmission of CO_2 to the offshore storage facility or facilities is a solution for achieving large reductions in CO_2 emissions in the short term (2030-2035). Part of the transmission will be done by ship.

- In the long term (towards 2050 and beyond), the CO_2 network can serve a useful function in achieving negative CO_2 emissions or building a circular economy, for example, by transporting CO_2 of biogenic origin to the industry clusters for making products such as plastics.

- A CO_2 network in the Netherlands can play an international linking role and, for example, also transport CO_2 from Germany and Belgium to storage facilities in the North Sea. Pipeline connections to other countries, such as Norway, are also a possibility in the more distant future.

- Transport of CO_2 by ship - via the rivers and the sea - will remain necessary and is an efficient alternative in particular for transporting smaller capacities (0.5 to 1 Mton per year) over distances of several hundred kilometres.

Infrastructure for heating

- Collective heat grids play a much stronger role in the supply of heat in the built environment in all scenarios for 2050 than they do today. There are however significant differences per scenario. The supply of heat via collective grids increases by a factor of five in the National Leadership scenario and only doubles in the International Trade scenario.

- Due to changes in supply, investment is needed in relatively large-scale heat transmission infrastructure that connects sources to one or more distribution networks. These transmission pipelines always remain regional in character though. The scale of investment is greater with a higher percentage of residual heat and geothermal heat.

- There is a strong need for heat storage in all scenarios. The volumes are described in Chapter 2: 4-11 TWh in 2040 and 3-14 TWh in 2050, with the largest volumes being needed in the National Leadership scenario.

9.2 Supply of and demand for CO_2 and the need for CO_2 transmission

According to the National Energy System Plan (NESP), carbon capture and storage (CCS) are needed if the Netherlands is to meet the national CO_2 reduction targets in the short term. The total capacity requirement in the Netherlands in 2030 will be about 20 Mtons of CCS (see II3050 scenario report, Section 4.7).

Transmission is needed to store the CO_2 captured in industrial clusters in empty gas fields under the North Sea. Large-scale projects such as Porthos and Aramis have been set up to make the final leg of this transmission route possible, from the Port of Rotterdam to suitable depleted gas fields offshore. Both onshore and offshore pipelines and other infrastructure need to be constructed for this. The maximum volume to be transported to storage is 22 Mtons of CO_2 per year, based on the infrastructure that is currently envisioned.

The other four major industrial clusters also produce CO_2, but it is as yet less clear how the captured CO_2 will be transported to storage facilities in those cases. The same is true of the large industrial clusters in Belgium and Germany, such as those near Antwerp and in the Ruhr region. Transport by ship, via rivers and by sea, is the main alternative to pipelines. Consequently, various clusters have made plans to transport CO_2 by ship to the Maasvlakte industrial park or to the offshore storage facilities. Research[40] has shown that transporting quantities of up to about 2 Mtons/year over distances of several hundred kilometres is best done by ship. Pipelines can be used efficiently when large quantities are involved and/or the distances are shorter (see Figure 62 in 9.3).

The next section describes the routes where installing a CO_2 pipeline is efficient and what a resulting network for CO_2 capture and storage might look like around 2035. It is essential to have a picture of the supply of captured CO_2 in the industrial clusters in this context. In the more distant future, after 2035, industry may also start demanding CO_2 as a raw material for making products, such as plastics. The CTM (Carbon Transition Model, see II3050 scenario report 4.7) has been used to determine the annual levels of CO_2 demand and supply for 2040 and 2050 in respect of the four scenarios in II3050-2. It seems that a high demand for carbon can arise: from 2 Mtons use of CO_2 (CCU) in the INT scenario to more than 15 Mtons in the NAT scenario.

For the years 2030 and 2035, the most recent scenarios of the network operators' investment plans were used, which are also based on the CTM. To estimate the transport needed, the figures were aggregated at the cluster level.

9.3 Development of a CO_2 network in the period to 2035

CO_2 transmission is different from natural gas transmission. At room temperature and under normal atmospheric conditions, CO_2 is a gas, but a phase transition occurs when it is subjected to high pressure. When the pressure is increased above 50 bars at a temperature of 15°C, a liquid is formed. Above 31°C and at pressures above 73 bars, CO_2 enters a supercritical phase, a form in which the distinction between gas and liquid disappears.
All forms - gas, liquid and supercritical - lend themselves well to transport through a pipeline - although phase transitions in the pipeline should be avoided. In practice, all these forms of transport have been used in various countries since the 1970s, for example in areas where oil is extracted.

At pressures just below the dew point, the process conditions required for a phase transition, condensation may arise, with both gas and liquid present. This is undesirable for pipeline transport. So CO_2 in gaseous form is preferably transported at fairly low pressures: 30 bars or lower. Liquid or supercritical CO_2 is best transported at

40 Element Energy, 'Shipping CO2 – UK Cost Estimation Study' report, November 2018

pressures up to about 80 bars, i.e. the pressure range that is also common in natural gas transmission.
When transported by ship, CO_2 is always in liquid form and this is similar to the transport of LPG and ammonia, for example.

When CO_2 is transported as a gas through a pipe, the capacity is much lower than when it is transported in liquid form through the same pipe. When transported in supercritical form however, the capacity almost the same as that for the liquid form. At present, it is not clear which pressure regime will be used in the Netherlands for transmitting CO_2 over long distances - the transmission may be partly gaseous and partly liquid/supercritical, depending on the route and conditions. Consequently, based on the supply and demand data alone, determining which pipe diameters should be chosen on the various routes under consideration is near impossible.
The following analysis only assesses the routes where a pipeline can be an efficient choice and not how large the diameter of the pipeline should be.

The analysis is based on the five major industry clusters in the Netherlands and the CO_2 supply and demand figures for each cluster. These five clusters account for most of the possible transport needs. The supply and demand data was specified by the largest companies themselves. Those figures can be found in Table 13.
International transport from Germany and Belgium is part of the analysis - this is especially relevant in scenarios with an international outlook (the INT and EUR scenarios are examples here).

Table 13: *Quantity of CO_2 per year in Mtons (demand = -; supply = +), base load (flat profile).*

Scenarios	2030KA	2030 IA	2035KA	2035 IA	2040 DEC	2040 NAT	2040 EUR	2040 INT	2050 REG basis	2050 NAT basis	2050 EUR basis	2050 INT basis
Clusters	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]	Net [Mtons/year]
Rotterdam – Moerdijk	8.7	8.6	8.1	7.6	6.8	7.6	8.8	7.8	3.2	-8.8	3.7	6.6
Zeeland	2.2	1.3	0.6	0.2	-0.3	-0.2	0.6	-0.2	-0.3	-2.6	-0.4	0.6
North Sea Canal area	0.0	0.0	0.5	0.0	1.5	1.0	0.8	0.0	0.0	0.0	0.8	0.0
Chemelot	1.2	0.9	0.7	0.2	0.4	0.0	1.2	0.0	-0.1	0.0	1.9	-0.1
Northern Netherlands	-0.1	0.0	0.5	-0.5	-0.7	-0.7	-0.4	-0.5	-0.8	-0.6	-0.6	0.5
Total Import (GER + BE)	9.80	8.8	-	-	-	-	-	-	0	7	20	10

In the period to about 2035, this mainly involves transporting CO_2 to storage under the North Sea.
The assumption is that the infrastructure from the Port of Rotterdam to the Porthos and Aramis storage facilities is already in place and has sufficient transmission capacity. The most important consideration is whether transport from the other clusters can be done most efficiently by pipeline or by ship. Safety also plays a role here: in densely populated regions, transmission by pipeline is preferable to transport by ship. In principle, these considerations result in a star-shaped network, without ring structures, running from the clusters to Rotterdam.

As described in 9.2, the choice to use a pipeline depends mainly on the transport distance and the amount of CO_2 to be transported. When transporting large quantities over relatively short distances, a pipeline is often more efficient than transport by ship. The relevant graphs (source: Element Energy[41])) are shown in Figure 62.

41 Element Energy, 'Shipping CO2 – UK Cost Estimation Study' report, November 2018

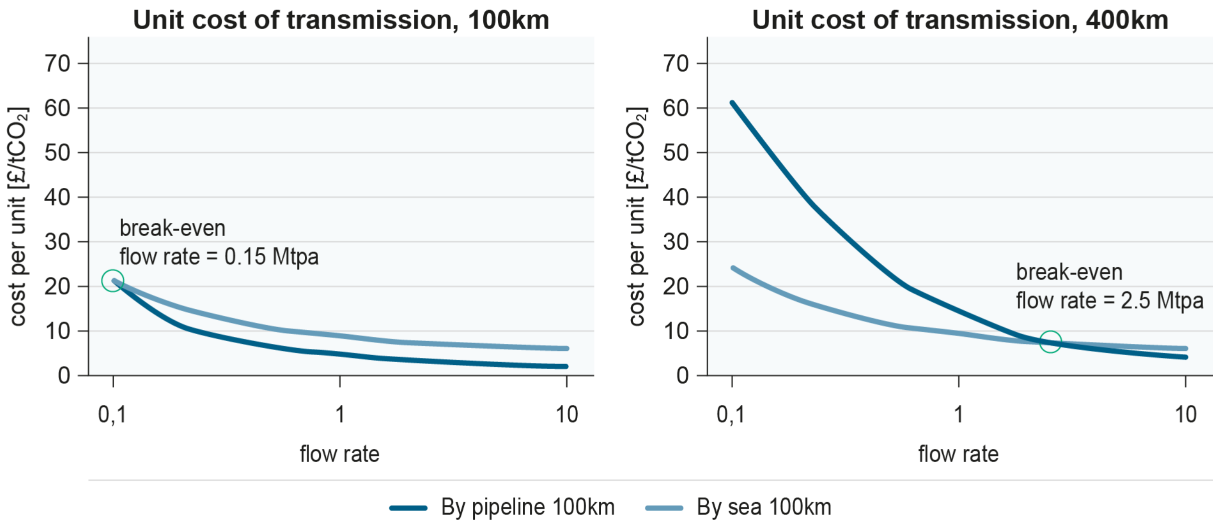

Figure 62: *Comparison of the costs of transporting CO_2 by ship and by pipeline, depending on distances and quantities to be transported.*

The estimated distances between the various clusters and the Port of Rotterdam are shown in Table 14. The analysis assumes that new CO_2 pipelines will be installed in existing pipeline corridor routes as far as possible.

Table 14: *Distances between clusters and the port of Rotterdam*

Cluster	Distance [km]	Comments
Zeeland	140	to Rotterdam/Moerdijk cluster
North Sea Canal area	100	to Rotterdam/Moerdijk cluster
Chemelot	250	to Rotterdam/Moerdijk cluster
Northern Netherlands	220	to North Sea Canal area (from there on to Rotterdam)
	280	to Rotterdam/Moerdijk cluster

The analysis shows that in the period to 2035, efficient connections can be established between the North Sea Canal area and Rotterdam, between Chemelot and Rotterdam and between the Zeeland industrial cluster and Rotterdam. In the case of the Chemelot connection, allowance has been made for extending it to the Ruhr region. The amount of CO_2 to be transported away from the Ruhr region is so great that the Chemelot-Rotterdam connection, via the Delta-Rhine Corridor, will act as the backbone of the CO_2 network in the Netherlands. Furthermore, allowance has been made for extending the connection to Zeeland to the industrial clusters in and around Antwerp and Ghent.

Due to the long transmission distance and relatively small quantities, a CO_2 connection between the industrial cluster in the north of the Netherlands and the other clusters seems not to be efficient in the period to 2035. Transport by ship to the Maasvlakte industrial park is a more logical solution. However, consideration could be given to a connection between the cluster in the north of the Netherlands and the nearby German industrial cluster in and around Bremen.

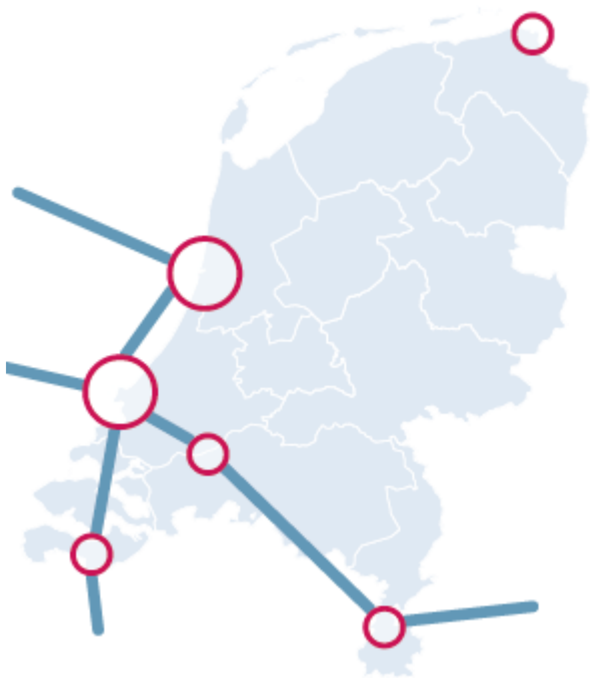

Figure 63: *Proposed CO_2 network in 2030 to 2035, based on an efficiency analysis. There are differences between the scenarios: in the European Integration and International Trade scenarios, the routes from Belgium and Germany have a higher capacity.*

9.4 CO_2 network development path in the period to 2050

Fossil fuels are going to play an ever diminishing role, so the supply of CO_2 captured from industry will decrease. A demand for CO_2 is expected to replace it, for example for the production of plastics, fertilisers, methanol and e-fuels and for use in greenhouses. Petroleum is largely used for those purposes now, but CO_2 also contains the carbon needed to make products of this type.

If CO_2 is used, plastics and other substances, such as synthetic fuels, can be made in a more sustainable manner. Furthermore, if CO_2 originating from industry that has previously been captured and stored is used, a process arises that has the potential for circularity, depending on the origin of the CO_2. On balance, no additional CO_2 is released into the atmosphere. If CO_2 is used that has been extracted directly from the air, through direct air capture for example, there may even be 'negative emissions', particularly if the CO_2 is then sequestered in a product for more than 100 years. The net result is that there is less CO_2 in the atmosphere than before. Exactly what is needed to achieve a circular economy and negative emissions is being investigated in multiple studies. Some technologies, for example direct air capture, are still much too expensive. Other technologies are still in their infancy and the extent to which they can ever become applied at scale is not clear. An example is storage in substances such as olivine. On the other hand, there are also encouraging developments that could speed up development of an approach to usefully reuse CO_2. The technology used for CO_2CLEANUP[42] is a good example.

If a substantial demand for CO_2 arises after 2035, in addition to the continuing demand for storage by industry, the network for CO_2 transmission built in previous years will continue to fulfil a useful purpose. For example, if a

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[42] SCW Systems, link: https://scwsystems.com/co2-clean-up/

lasting and wholehearted commitment is made to synthetic fuel production, utilisation becomes the driving force rather than storage. The end result then is that supply and demand will be distributed differently across the CO_2 system. Transmission of CO_2 remains necessary in all cases, but the direction of flow may reverse, with the industrial clusters as the destination rather than the source. The network can continue to fulfil its transmission function well beyond 2050.

All in all, it cannot even be ruled out that the cluster in the north of the Netherlands may also be connected to the other clusters in the Netherlands via a CO_2 pipeline. International connections in the North Sea with surrounding countries, as far away as Norway, are also being considered. Ships will then undoubtedly play a role, but offshore pipelines are also clearly in the picture. Depending on the scenario unfolding towards 2050, a large-scale Northwest European network of pipelines and ship connections could emerge. Figure 64 presents a possible design for this vision.

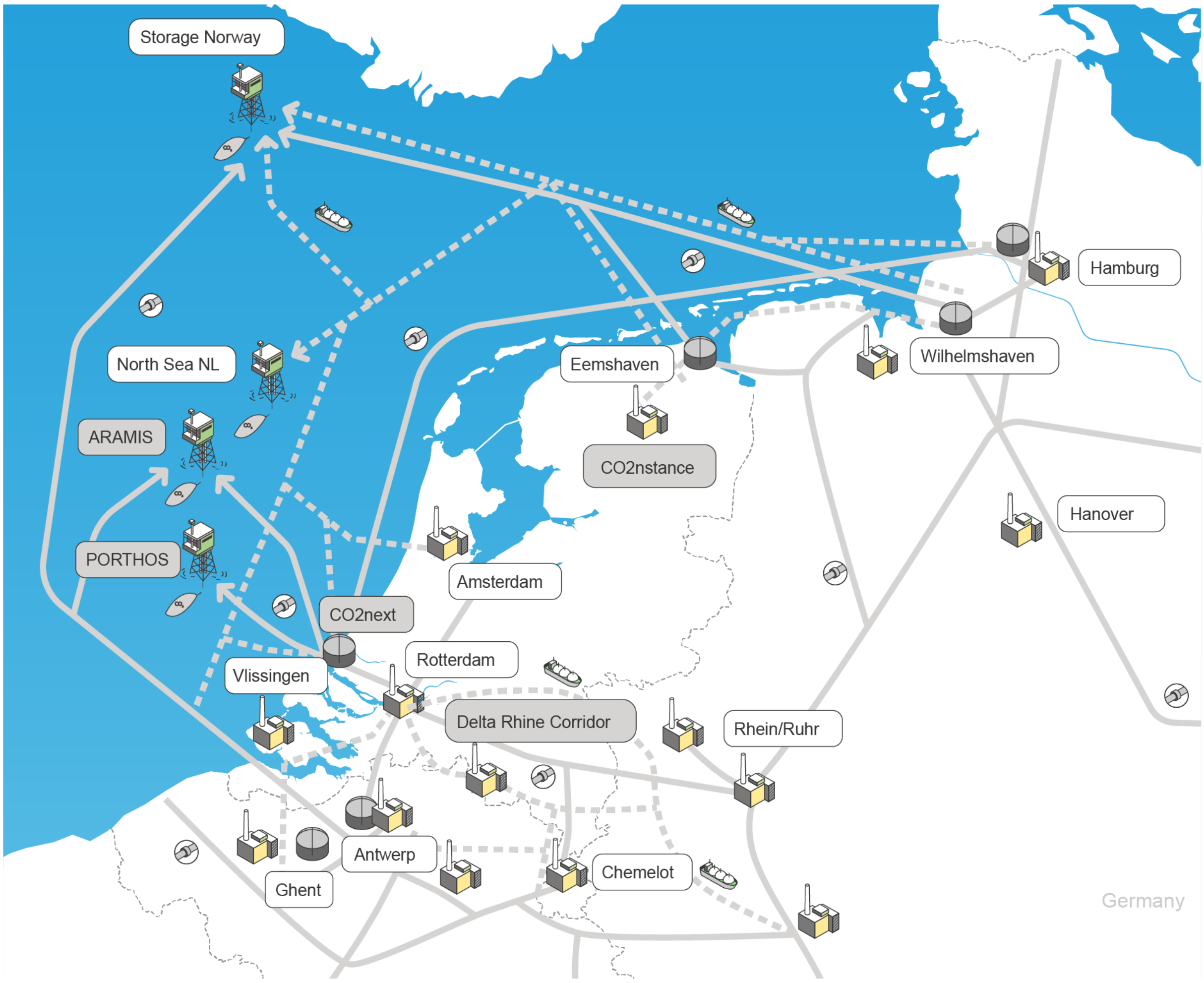

Figure 64: *Future vision of possible CO_2 connections via pipelines and ships in 2050 in Northwest Europe (source: Gasunie).*

9.5 Heat: the current heat grids

In 2019, the demand for heat supplied as heat distributed in heat grids was 47 TWh. The current demand comes mainly from industry (23 TWh) and greenhouse horticulture (15 TWh) and much less from the built environment

(6 TWh). The supply of heat in 2019 came from a combination of sources, including waste heat from local CHP units (14 TWh), and gas boilers (10 TWh). Some of the heat was produced with natural gas. Other sources, such as waste incineration plants (WIPs), bio-heat plants, heat boilers and geothermal energy - i.e. heat from deep underground - play a smaller role.

Very local infrastructure is often involved here, for example heat from a CHP unit supplied to a next-door greenhouse. The section below describes the development of collective heat grids for the built environment towards 2050.

9.6 Heat supply and demand and infrastructure developments in the period to 2050

9.6.1 Supply and demand developments

The supply of and demand for heat via heat grids change over time in the scenarios as shown in Figure 65 and Figure 66.

The nature of this heat transfer will change dramatically in the period to 2050: from ‘heat grids’ in an industrial and agricultural context - this is largely an accounting exercise, with little actual infrastructure - to the large-scale residential use of heat, which does require significant infrastructure. A lot will also change in greenhouse horticulture: from many greenhouses with a CHP unit and with little heat infrastructure to, for example, shared geothermal wells and thus the need for more heat infrastructure. These changes occur in every scenario.

- In the Decentral Initiatives scenario, a great deal of (residual) heat is supplied by industry. Geothermal energy and solar thermal energy also play a significant role in this scenario. The main heat source, as in the other scenarios, is power-to-heat: electric boilers and heat pumps.

- In the National Leadership scenario, heat is provided mainly by electric boilers, heat pumps and geothermal resources. This scenario is characterised by a heat demand that is four times higher than the current level in the built environment, because many homes and buildings are connected to a heat grid in this scenario.

- The heat demand in the European Integration scenario decreases by a third compared to today's level. The increase in heat demand in greenhouse horticulture lags behind in the scenarios referred to above.

- The International Trade scenario shows the lowest heat demand: the demand for heat distributed in heat grids only doubles. The level of demand from agriculture shrinks the most.

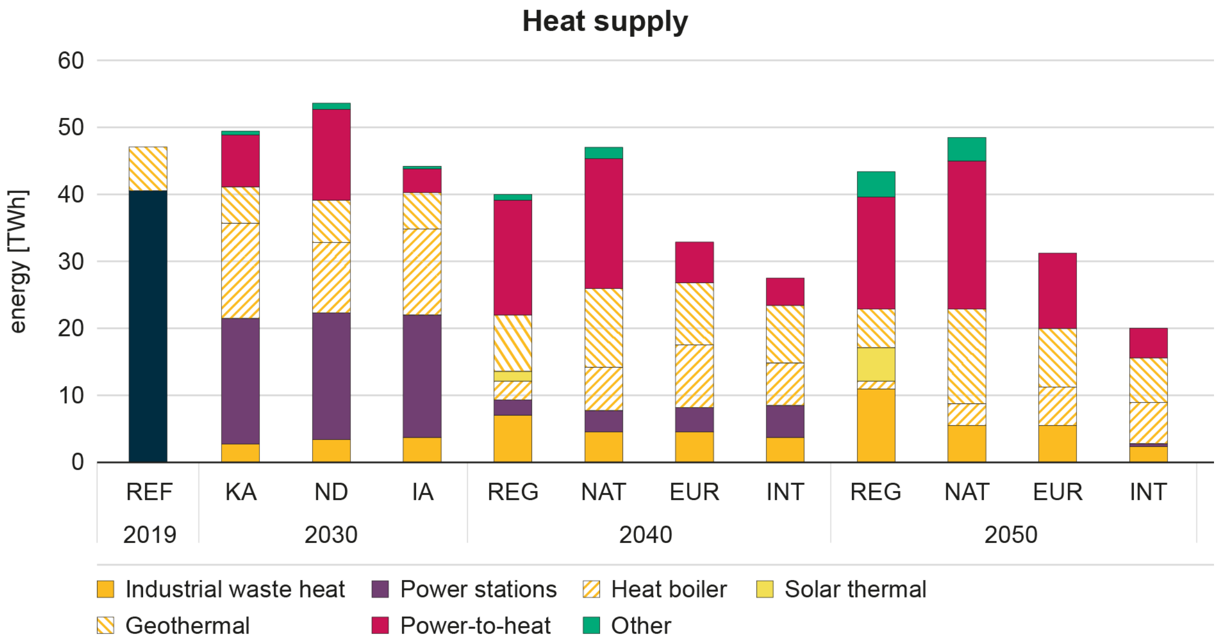

Figure 65. *The supply of heat for distribution in heat grids in 2019 and its development in the period to 2050, in TWh.*

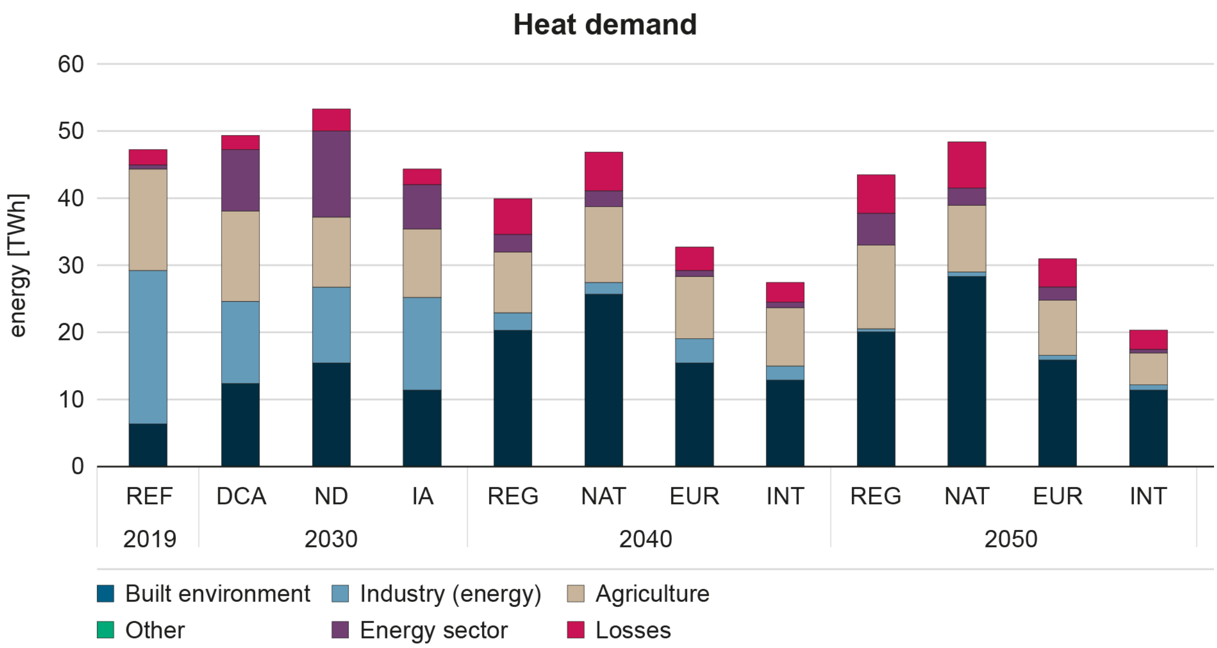

Figure 66. *The demand for heat distributed in heat grids in 2019 and its development in the period to 2050, in TWh.*

9.6.2 Infrastructure needs for heat transmission

Much of the current use of (residual) heat is concentrated in industry and the greenhouse and horticulture sectors, where heat is often generated locally. Partly due to the shift in the use of heat from industry to the built environment, the transmission requirement for heat increases in all scenarios compared to the current low level.

The increase in the use of heat in the built environment necessitates the construction of new distribution networks in all scenarios. These new, collective heat grids are expected to operate at lower temperatures than most of the current grids. This is not only because the consumers of the heat can get by at lower temperatures due to better insulation, but also because many of the providers will make (residual) heat available at lower temperatures in the future - much more so than CHP units and power stations do today.

In the Decentral Initiatives and National Leadership scenarios, relatively large amounts of waste heat from electrolysers become available, but the sources are generally not directly adjacent to heat demand in the built environment. The greatest transmission demand is expected to arise as a result of this industrial residual heat, because industry and homes are generally not located near each other. Drilling locations for geothermal energy should preferably be chosen close to customers, as we see, for example, in developments in the Westland region; this means that geothermal energy is often associated with a lower transmission requirement.

In the Decentral Initiatives scenario, more residual heat is accessed for the built environment; as a result, this scenario is where the greatest need for heat transmission pipelines arises. Heat transmission, by definition, becomes concentrated in regions where residual heat and/or geothermal resources are available. In the case of residual heat, that is around the major industrial clusters. In the case of geothermal heat, the Rotterdam/Moerdijk area, the North Sea Canal area and to a lesser extent Groningen/Eemshaven and North Brabant (see Figure 67) are concentration hot spots.

Heat grids fed by power-to-heat are mainly supplied by local sources, and this is reflected in the electricity infrastructure required. The residual heat sources and geothermal sources are primarily associated with the need for transmission over relatively long distances.

Decentral Initiatives

The use of residual heat from industry is greatest in this scenario, and geothermal energy also plays a significant role. A great deal of residual heat comes from electrolysers, which are not located in the immediate vicinity of the residential districts. Consequently, to connect demand with supply, there is a significant requirement for heat transmission. That requirement is greatest in Zuid-Holland province.

National leadership

The National Leadership scenario calls for slightly more heat transmission than the Decentral Initiatives scenario. The supply of residual heat from electrolysers and industry halves compared to that scenario. Geothermal energy, by contrast, is much more significant (from 6 to 13.8 TWh) and needs to be connected to the areas where there is demand. In addition to Zuid-Holland, Groningen and Drenthe, we also see a requirement for heat in Noord-Holland and Brabant.

European integration

The need for transmission pipelines in this scenario is similar to that in the National Leadership scenario. Because geothermal energy plays a significantly smaller role here than in the National Leadership scenario, we see fewer transmission pipelines and a relative shift of investment toward the industrial clusters.

International trade

Compared to the other scenarios, the need for additional transmission pipelines for heat is very limited in this scenario. Relative to the transmission pipelines that already exist or are under construction, only a dozen kilometres of additional pipeline are added, mainly in Zuid-Holland province.

Table 15: *Requirement for heat transmission infrastructure, DN500 - DN1000 (pipe diameter approx. 50 to 100 cm)*

	Decentral Initiatives	National leadership	European integration	International Trade
2040	approx. 300 km	approx. 350 km	approx. 250 km	approx. 150 km
2050	approx. 350 km	approx. 400 km	approx. 280 km	approx. 180 km

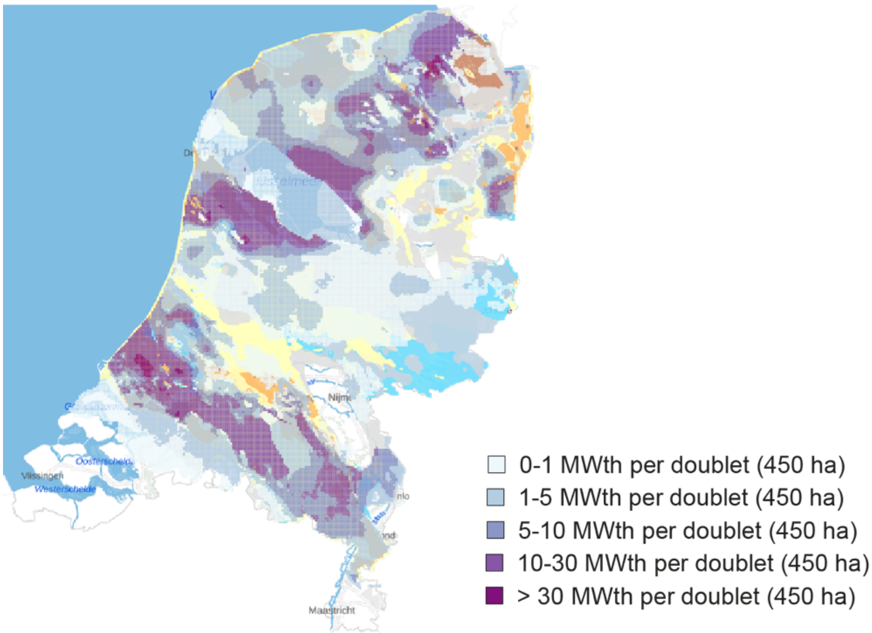

Figure 67: *Potential geothermal energy areas.*
Source: https://www.warmteatlas.nl/

Chapter 10

Overall impact on infrastructure

10.1 Conclusions and recommendations

- The future energy system can be optimised - in terms of cost, space, etc. - by taking an integrated look at the impact across all the grids and networks. After all, the infrastructures for the different energy carriers are interconnected, so a bottleneck in one subsystem is sometimes best solved by a measure in a different subsystem. This requires integrated assessments, based on looking 'across all the grids and networks'. Network operators are uniquely positioned to further develop these types of solution and demonstrate that there is added value in an integrated approach.

- At present, no models provide the output needed for integrated assessment of all facets of the energy system at the same time. Potential effects are already evident based on the examples in this chapter. However, developing computational models that can deliver more quantitative support is to be recommended.

- Installing hybrid heat pumps is an example of system integration at the regional network operator level. When there is a shortage of sustainable generation, especially outside the period of peak demand, bottlenecks in the regional electricity grid can be avoided through controlled, large-scale use of the electric resources, or the gas resources, or the hydrogen resources.

- An example of system integration at the level of the national network operators is integration of the national onshore electricity and hydrogen grids with the offshore infrastructure that is to be developed. The baseline scenarios assume 38 to 72 GW of offshore wind energy and 16 to 45 GW of electrolysis capacity in 2050. Offshore electrolysis hubs, from which wind energy can be brought to land both as electricity and in the form of hydrogen, are examples of system integration and effective spatial incorporation of flexibility resources and infrastructure. Hybrid hubs are more flexible and can therefore serve both the electricity and hydrogen markets, depending on the level of demand and the price trends. In addition, they lead to a higher and optimal utilisation of electricity cables running from the sea to the shore, resulting in more landfall with less infrastructure.
  How this development will evolve in the coming years is a subject for investigation. It depends, among other things, on the development in electricity and hydrogen demand, cost developments related to offshore electrolysis and the impact of international electrical connections. Within this integrated context, the optimal shares of electricity and hydrogen landfall by TenneT, Gasunie and other relevant parties should be further investigated.

- Methanation - the conversion of hydrogen to methane - has been explored as a way to make it easier to achieve sustainability in the built environment. However, this option appears to be a relatively expensive alternative and therefore a societally undesirable solution.

10.2 Integrated approach to the energy system

The energy carriers of the energy system of the future - electricity, hydrogen, methane and heat - are highly intertwined and connected. This interconnectedness can be viewed from different perspectives, for example:

1. *At the level of the energy balance*
   The demand for and supply of energy are not in equilibrium everywhere and at all times. In the past, supply (e.g. of natural gas) could be adjusted relatively easily. But with an increasing share of wind and solar, the weather-dependent, and thus non-dispatchable, volatility of supply becomes greater and greater.
   Conceptually, there are three approaches to resolving imbalance in the system:
   - When the energy is needed in a different place, that requires transmission;
   - When the energy is needed at a different time, that requires temporary storage;
   - When the energy is needed in a different form, that requires conversion to a different energy carrier.

   Conversion and storage are both aspects of flexibility, which also includes, for example, controlling supply and demand. Transportation and flexibility are strongly related and are, to a certain extent, communicating vessels: if the right choices are made in respect of location, behaviour and form to achieve flexibility, less transmission is needed and the energy system can be optimised in terms of cost, space, resources and the deployment of manpower.

2. *At the sector or market level*
   Industry, agriculture, the mobility sector, the built environment, etc. all use energy. Each sector influences what is possible or impossible for the other sectors through its pattern of consumption. Industry is increasingly adopting electrification and using less natural gas. If industry demands a lot of hydrogen in the future, less hydrogen will be available for mobility. In other words, the degree of interconnection between the different demand sectors is increasing. In the light of this, one prerequisite for setting up an optimal system is that sectors must be linked in the right ways. This is why system integration is also sometimes referred to as sector linking.

3. *At the network level*
   The energy system is partly composed of a number of networks for transmitting energy.
   At the national level, these are TenneT's high-voltage grids and Gasunie's high-pressure grids.
   At the regional and local level, these are the gas and electricity networks of the regional network operators.
   These networks are interconnected and they influence and support each other. This also means that a bottleneck in one network can sometimes be resolved by an adjustment in another network.
   The interaction between the grids will continue to increase in the coming years: for example, installing electrolysers will lead to greater integration between the electricity and hydrogen grids. There are a number of variants for system integration at the network level:
   - Between the different national networks, such as electricity-hydrogen, with interconnection via electrolysis and power stations, but also, for example, hydrogen gas, via methanation.
   - Between national and regional grids, such as at substations between high and medium voltage, or at green gas boosters from the gas distribution grids to the regional transport pipeline network.
   - Between regional grids. This involves interconnection of electricity or gas networks operated by different regional network operators, but also, for example, interconnection of the gas and electricity grids within a regional operator's network, via hybrid heat pumps or via local electrolysis.

4. *At the level of space utilisation and costs*
   System integration also aims to optimise the energy system in terms of cost and space utilisation. The aim is to achieve a reliable and efficient system at the lowest possible cost, with acceptable use of space. In a densely populated country like the Netherlands, space is a scarce commodity; moreover, it must be shared

with other infrastructures, such as roads, inland navigation routes and residential areas. The *Programma Energiehoofdinfrastructuur* (PEH), among other things, encourages grouping energy infrastructure in reserved swathes of land whenever possible. Grouping electricity cables and gas infrastructure in the same swathe of land - also an example of integration - may, subject to strict safety conditions, perhaps be a solution.

5. *Integration of the energy system and the feedstocks system*
   Electricity and heat are energy carriers, natural gas is both an energy carrier and a feedstock, hydrogen is at present mainly a feedstock and will soon increasingly become an energy carrier. As natural gas disappears from the system in the period to 2050, CO_2 - currently an unwanted waste product - can also become a useful feedstock. Industry will continue to need carbon atoms for the production of plastics and other materials far into the future. As a result, the energy system and the feedstock system will become even more intertwined than they already are.

The strong reciprocal influence of the various subsystems means that a stand-alone bottleneck analysis and plan for a particular subsystem, for example the electricity grid, is automatically always incomplete. After all, there is interaction with other subsystems - in this case, with the hydrogen network, via electrolysis and power stations. Because of this reciprocal interaction, the optimal solution to a bottleneck in one subsystem may lie in a modification in another subsystem. Network operators are well-equipped to further develop these types of solution ‘across the grids and networks’ and demonstrate that there is added value in an integrated approach.
The following sections analyse this at a greater level of detail. They illustrate what is already possible today, based on meaningful examples.

10.3 Elaborations of integrated assessments

System integration - in the sense of looking for solutions to bottlenecks ‘across the grids and networks’ - can lead to a more effectively designed energy system. The system may be easier to operate than without system integration, and, furthermore, system developments will be easier to implement, costs will be lower, and space usage will be minimised. The usefulness of system integration is obvious: if the national hydrogen and electricity grids are not interconnected, balancing supply and demand in the electricity grid becomes a very challenging task, especially when it comes to seasonal variations. For now, storing hydrogen in salt caverns appears to be the only option for smoothing these large-scale variations over long periods of time. Interconnecting the two grids via electrolysis and hydrogen-fuelled power stations is essential in this regard and the need to do so will only become more pressing over time.

Integrated calculations for the complete energy system are difficult to produce at this point in time. Subsystems can be analysed however, but the network models currently in use determine the extent to which quantitative results are achievable. Scientists have been tasked with coming up with computational models for properly calculating the combined behaviour of both the electricity systems and gas systems. What does not help in this regard is that electricity and gas transmission take place on different time scales: electricity transmission at the European scale is a matter of milliseconds, while gas transmission from one end of a country to the other takes hours. This fundamental difference means that electricity and gas have very different properties: intervening in a gas flow to prevent a bottleneck is different and often easier than intervening in an oversupply situation in an electricity transmission context.

So, by necessity, the reflections in this chapter are mostly qualitative in nature. They do as much justice as possible to the various infrastructures and the interactions between them. The following sections discuss examples of system integration at the national level, for electricity and hydrogen, as well as, for example, the deployment of hybrid heat pumps in households.

10.4 Further exploration: some cases for systems integration

10.4.1 Case 1: Hybrid landfall arrangement for offshore wind

The installed capacity of offshore wind in the Netherlands is expected to be 21.5 GW in 2030, which then rises to between 38 and 72 GW in 2050, depending on the scenario. In the National Leadership scenario, 20 GW of the 72 GW will be brought to the shore in the form of hydrogen. This can be achieved through dedicated offshore electrolysis, or through a hybrid solution, where the offshore hub is connected to the mainland by both cables and pipelines.

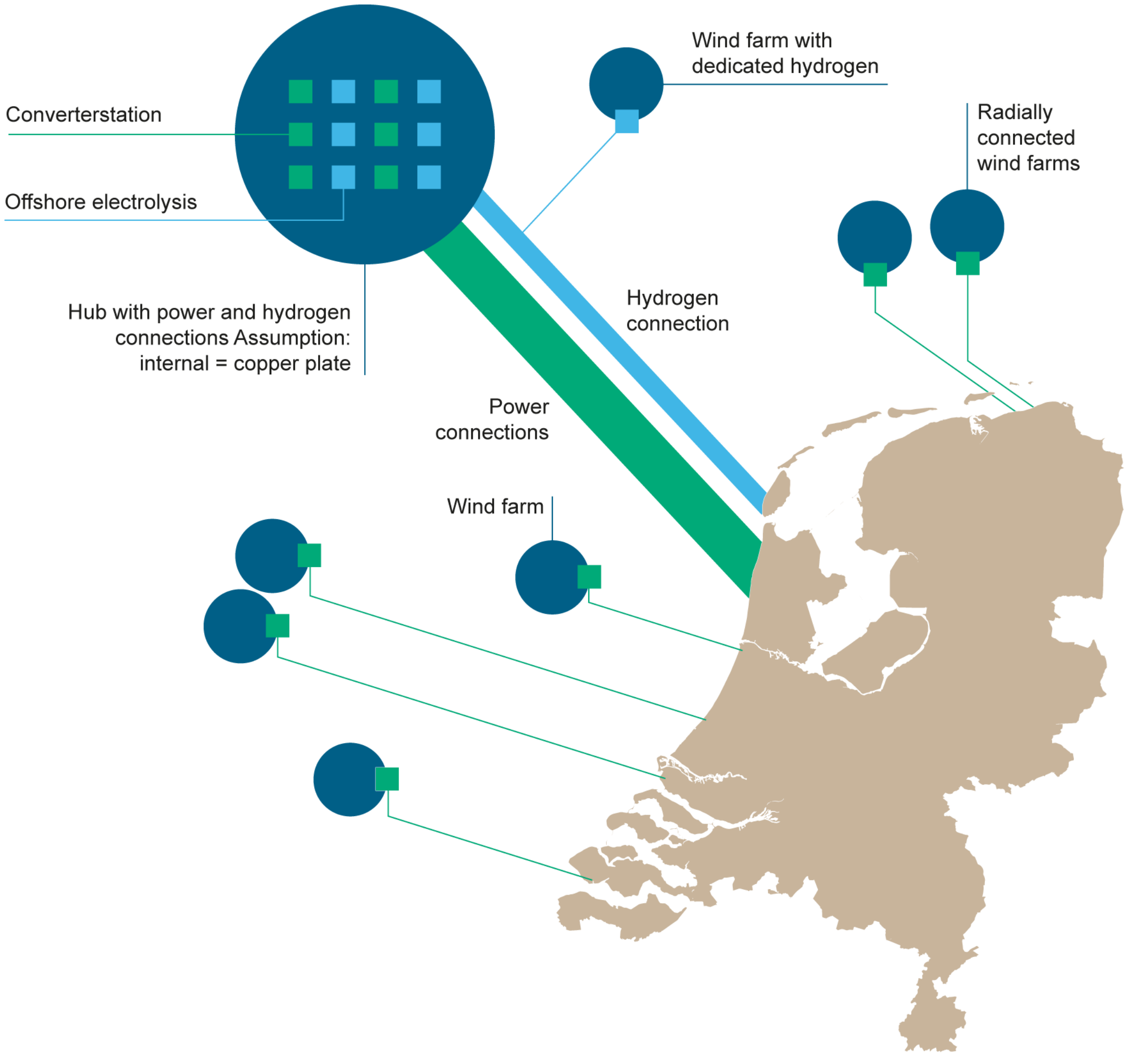

Figure 68: *Possibilities for bringing wind power produced offshore to the mainland (schematic)*

Many wind farms are connected 'radially' from an electrical design point of view. The hydrogen connections are likely to be engineered as a pipeline ring, connecting to the onshore hydrogen network at two locations. This configuration for hydrogen allows multiple electrolysis sites – at wind farms in different wind areas – to be connected, at the lowest cost. Figure 69 shows an impression of the hydrogen network. A possible overall design for both the electricity and hydrogen connections in 2050 is shown in Figure 70.

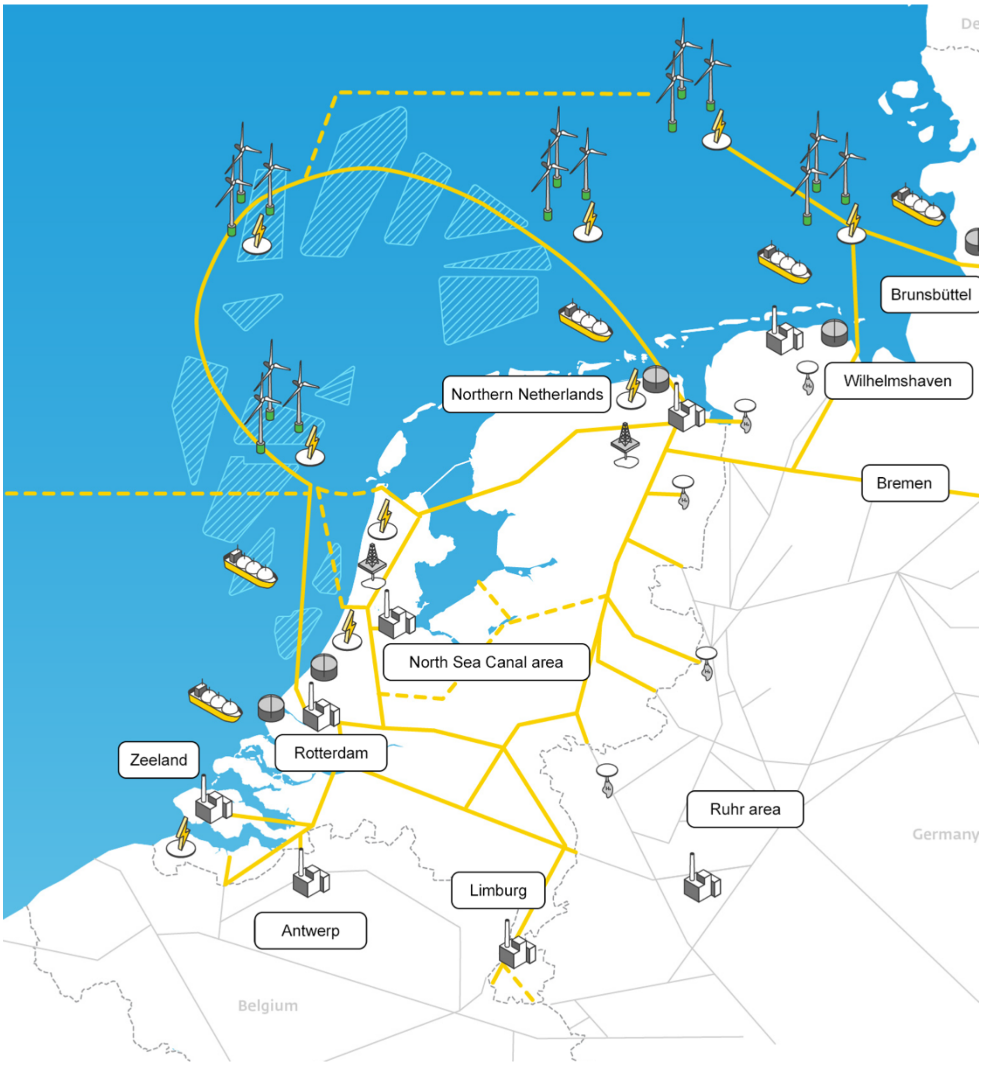

Figure 69: *Impression of the offshore hydrogen infrastructure and its connection to the onshore hydrogen network.*

Onshore electrolysis plays an important role in building flexibility into the energy system. Offshore electrolysis can have the same effect, but only if the hybrid solution is chosen. The following explanation clarifies how hybrid connection can contribute to an optimal design of the overall energy system, onshore and offshore.

Initially, at least until 2030, wind farms will be connected electrically in almost all cases. This is for several reasons, including the fact that a rapid scale-up of electricity generation also allows for rapid electrification of the demand, but also because the later wind farms will lie much further offshore, with correspondingly higher transmission costs for electricity. In the period from 2030 to 2040, incorporating a greater element of offshore wind into the electricity system becomes more challenging. The number of times when offshore wind electricity generation exceeds demand will grow rapidly. In addition, there is limited space on the coast for bringing more cables ashore and for upgrading the onshore grid. Flexible offshore electrolysis could be a solution here, by reducing the spatial impact on land, by providing flexibility to facilitate the integration of electricity into the system and by supplying the emerging hydrogen market with sufficient molecules. In this context, it is important to match the split between electrons and molecules to the development in the demand for electricity and hydrogen. This is handled for example in the OWLFS programme investigating ways of landing offshore wind power.

Suppose that 35 GW of electricity needs to be brought ashore in 2050, i.e. half of the total of 70 GW. In line with the above, the first 35 GW of wind power can be brought ashore purely as electricity. An alternative (theoretically) is to bring ashore 50% of the power produced by each farm contributing to the total of 70 GW in the form of electricity, the maximum hybrid option. The result seems to be the same, 35 GW of electricity and 35 GW of hydrogen are brought ashore. But, from a system perspective, there is a world of difference. Suppose the wind drops to a breeze at a certain time, causing the wind farms to operate at 20% of their power capacity. In the first case, only 7 GW can be brought ashore as electricity, compared to 14 GW in the second case. So, in the second case, there are far fewer shortages and there is also a much lower requirement for expensive balancing and flexibility options.

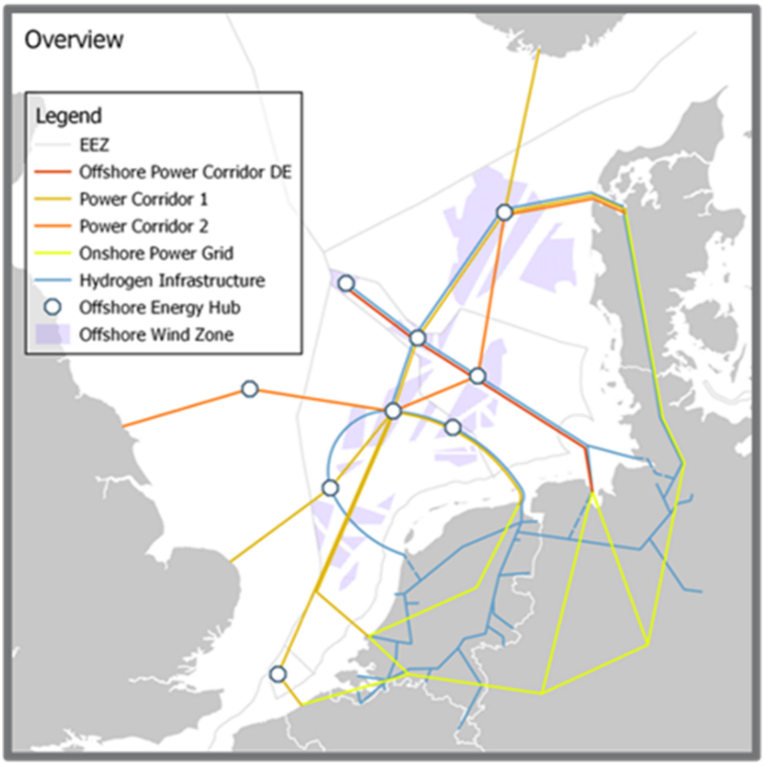

Figure 70: *The possible North Sea infrastructure in the long term and its connection to the networks onshore (source: EnergieHub NL).*

The conclusion here is that, from an energy system perspective, having the electricity cables more dispersed, rather than clustered, may have significant added value. Another conclusion is that a hybrid grid design can handle higher direct consumption with fewer cables. The optimal electricity/hydrogen ratio of the power brought ashore - set at 50/50 in the example - is still a subject for further investigation.

An electrolysis hub can be deployed in various ways. So the question is: under what conditions is hydrogen produced, under what conditions is electricity transmitted to the coast, and what combinations of the two are relevant? A deployment based on market prices is obvious and would mirror the onshore deployment of electrolysis. Basically, there are three situations:

1. *Wind in abundance*
   When the maximum capacity of electricity interconnections and offshore electrolysis is equal to the installed wind power capacity, there is no choice regarding the deployment of wind power. After all, both the electricity connections and the offshore electrolysis systems are being used at their maximum capacity.

2. Wind at, for example, 50% capacity
   With a 50/50 split between offshore electricity capacity and electrolysis, there is a choice of deployment. Two extremes:
   - Full use of the electrical infrastructure, with offshore electrolysis ‘switched off’. This is possible in a situation of equal direct demand for electricity, without conversion.
   - Full use of offshore electrolysis, and no use of the electrical infrastructure. This is possible in a situation of surplus electrical production relative to the level of electrical demand, which is then converted to hydrogen via electrolysis.
   - A situation between the two extremes, involving both offshore electrolysis and bringing electricity ashore, is also possible (and more likely). A choice between the two forms must then be made, based, for example, on market prices and ‘willingness to pay’. There may be other deployment strategies.

3. No/little wind, but abundant onshore solar power
   The wind farm is not producing any energy. The offshore electrolysers can be used to produce hydrogen with the onshore solar energy. The hydrogen is then transported back to the mainland. This does involve a lot of transmission of electricity and hydrogen, with all the associated losses. Further investigation is required to determine whether this set-up offers benefits.

Other aspects also affect these system questions, for example the size of the connection for electricity with foreign countries. Some of the electricity generated offshore could possibly be used directly in Belgium or Germany, if the supply needs in the Netherlands are already fully covered at that time. This requires thorough analysis of the state and behaviour of the market in those countries on an hourly basis. Some scenarios for Germany, as described in the German Netzentwicklungsplan (network development plan), actually show a surplus on an annual basis, i.e. a situation where wind and solar power together produce more than the base load. TenneT specifically is responsible for mapping the interconnection of electricity as accurately as possible. At the time of this outlook, the calculation tools needed to come to conclusions on the overall end picture were not yet available.

Another aspect that has yet to be explored is the extent to which the hybrid deployment of electrolysis at sea has an effect on transmission and flexibility on the mainland. This includes, for example, the utilisation of future hydrogen-fuelled power stations in terms of operating hours. Calculations for these types of analysis will be prepared as a follow-up to this outlook.

Finally, offshore electrolysis where the energy is only brought ashore as hydrogen - dedicated electrolysis - is a less flexible variant than the hybrid option. Dedicated large-scale electrolysis is therefore not preferred. It may be set up for specific situations in the future.

10.4.2 Case 2: Impact of (hybrid) heat pumps on regional operators' networks

Hybrid and all-electric heat pumps offer significant sustainability and energy-efficiency benefits. Table 16 shows the annual electricity use and associated gas savings for two types of heat pump, for different house types. It has been assumed that new homes are better insulated than existing homes.

With an all-electric heat pump, a household can be completely disconnected from the gas mains. A hybrid heat pump still requires a gas connection.

Table 16: *Electricity use and gas saving for hybrid and all-electric heat pumps on an annual basis (key figures taken from the 2021 Energy Top Sector report[43])*

Utilisation as a percentage of time		70%	30%		
	KWh-th/ year	Hybrid HP (kWh)	Gas saving (m^3/year)	All-electric HP (kWh)	Gas saving (m^3/year)
New terraced house	5000	1000	421	1429	602
Existing terraced house	6500	1300	548	1857	783
New detached house	12000	2400	1012	3429	1445
Existing detached house	14000	2800	1180	4000	1686

Seasonal and diurnal patterns will continue to strongly affect heat demand, even when combined with solar panels. After all, solar panels produce the most power during the day in the warmer months, while the greatest heat demand generally occurs in the cold months. The question is whether and how heat pumps can provide flexibility services through system integration. The answers underline the characteristics of heat pumps and the effect their deployment has on the gas and electricity grids.

Firstly, the increasing use of hybrid and all-electric heat pumps in the Netherlands has an impact on the low-voltage and medium-voltage electricity grids of the regional network operators:

- All-electric heat pumps have a major impact on the electricity grid, especially during peak periods. At the coldest times of the year, they can collectively lead to a high demand for electricity to meet the total heat demand.

- Hybrid heat pumps primarily use gas for peak performance and do not put a load on the electricity grid at that time. The originally constructed gas supply capacity is still utilised at such times. Over the year as a whole, however, there is a significant reduction in gas consumption because as temperatures rise the unit switches to the electric heat pump.

Because heat pumps can be turned on or off within minutes, they are technically suitable for use as flexibility resources. Hybrid heat pumps can additionally switch over to gas - in the future, sustainable gas, i.e. green gas or hydrogen. The ability, in principle, to control the heat pumps at the individual or collective level offers opportunities for grid load smoothing and possibly even peak reduction.

[43] Link: https://topsectorenergie.nl/documents/139/Flexibele-inzet-warmtepompen-voor-een-duurzaam-energiesysteem.pdf

If collective control were possible, for example, in the event of a shortage of sustainable electricity or grid capacity, some of the hybrid heat pumps could switch to using gas to avoid electricity grid bottlenecks. This would need to be a sophisticated form of control ('scarcity-neutral') to avoid exacerbating problems in the local grids. Collective control of electric heat pumps can additionally help to a limited extent in increasing non-simultaneous switching, but mainly outside the true peak times.

So hybrid heat pumps in particular contribute to system integration, resulting in optimal utilisation of the overall system. The overall effect may be limited in magnitude, yet may still be enough to avoid costly measures.

There are also risks. If control of the heat pumps is market-driven rather than grid-oriented, the simultaneity factor may even increase and any peak usage may coincide with a high grid load.

10.4.3 Other examples of system integration

In addition to the situations already analysed, there are many more examples of system integration. Some have already been studied in more detail; others deserve to be worked out further in a detailed follow-up to this outlook.

- **Distributing residual heat generated by electrolysers**
  Even with a useful efficiency of 70%, an electrolyser still produces a lot of heat, with temperatures reaching up to 80°C. All or part of that heat can be reused to heat buildings. Large-scale electrolysis is expected to be mostly on the coast, sometimes in or near an industrial cluster. In that case, the heat can be used locally for heating business premises. Another option is to distribute residual heat to the built environment elsewhere. If the electrolyser is not installed near a residential district, construction of a heat grid is unavoidable. Heat, electricity and hydrogen are therefore interlinked, and system integration is a logical approach: by choosing the location of the electrolyser favourably, the energy system set-up can be optimised overall in terms of space, cost, etc. Large amounts of heat are involved: a 1 GW electrolyser running at full capacity for 4,000 hours theoretically produces up to 1 TWh of residual heat, enough to heat thousands or even tens of thousands of homes.

- **Use of (hydrogen) compression for electricity grid balancing**
  The current national natural gas network is equipped with compressor stations to keep the gas in the pipelines at the required pressures. Some of the compressors, especially the more modern versions, are electrically powered and these compressor stations are connected to TenneT's high-voltage grid. The compressors often do not run continuously, but are switched on and off depending on the gas transmission situation.
  This involves hundreds of MW of power that can be deployed if needed. In theory, the process of ramping up and ramping down electric compressors offers opportunities for interaction with TenneT's electricity grid. It is conceivable that TenneT would be aided in certain situations by a lower deployment of the compressors, or a higher deployment, as this might prevent a temporary bottleneck. Ramping up and ramping down compression can be done quickly - on an hourly basis - and is thus suitable in principle as an operational measure. Varying the deployment of compressors does mean that the gas network may not be running at peak transmission capacity; i.e. a lower pressure is still acceptable somewhere else in the network. Against the background of a declining level of demand for natural gas, this form of system integration may be especially interesting in the future in an interaction with the hydrogen network. The hydrogen grid is also expected to be equipped with compressor stations after 2030. These hydrogen compressor stations will be built as far as possible at existing locations spread across the country.

- **Methanation**
  Methanation, on balance, seems to be a societally undesirable solution. The costs are too high for the moment. In the International Trade scenario, a large proportion of the hybrid heat pumps in the built

environment run on hydrogen in 2050. This may be a good solution, but it requires replacement of all the gas boilers in order to use hydrogen. An alternative is to partially convert the assumed ample supply of hydrogen back to methane, through a process called methanation. This can only be done in an environmentally friendly manner if CO_2 of biogenic origin is also available, in addition to hydrogen. In a methanation scenario, the systems for hydrogen, green gas and CO_2 become more closely linked and one can then, in principle, start looking for a cost-optimal combination; in other words, this is another case of system integration.
The feasibility of methanation for the benefit of the built environment in the Netherlands has recently been investigated in technical and cost terms in two reports[44]. Although the cost to households under a targeted policy is not very different in the two cases, the outcomes indicate that, based on the current state of technical knowledge, the methanation value chain as a whole, including additional electricity generation for the process, is more expensive than choosing to use hydrogen in the built environment.

[44] J. H. Osinga, *Exploring the Potential Role of Synthetic Methane for Domestic Hybrid Heating Systems - Comparison Study between Hydrogen and Synthetic Methane for the Dutch Residential Market*, Report: EES-2021-460, University of Groningen, March 2021; M.A. Boekenstijn, *Comparative Analysis of Hydrogen and Green Gas from Methanation to Substitute Natural Gas in Dutch Households*, Hanze University of Applied Sciences Groningen, November 2022

Part 3:

Overarching themes

Chapter 11

Cost, space, feasibility and raw materials

11.1 Conclusions

- In the four scenarios of II3050-2, the national annual costs exceed the current energy system costs. The latter costs would rise sharply anyway, even without the energy transition. The differences in total costs between the scenarios are limited. However, the composition of the costs does vary widely between the scenarios.

- Modifications to buildings, installations and production equipment are the main cost drivers, accounting for more than 50% of the costs. The costs of infrastructure and flexibility resources - storage and conversion - account for 20% to 30% of the total energy system costs. In addition, in the European Integration and International Trade scenarios, the costs for energy carriers are significant due to the import of energy carriers (20%). The latter costs are sensitive to price fluctuations in the international market.

- The analyses show that the energy transition leads to a sharp increase in demand for transmission capacity on the EHV grid. To facilitate this, major expansion and upgrading of the infrastructure will be needed. In the Decentral Initiatives scenario, a network expansion of approximately 320 km is envisioned; about a 20% increase in the route length of the current EHV grid in 2023. The European Integration scenario requires about 510 km of new connection infrastructure (+33%). Assuming a corridor width of 100 metres, this utilises a surface area of between 32 and 51 km^2.

- For the 110/150kV grid, the space requirement consists of the space utilisation for new high-voltage stations, to increase capacity for transmission towards the regional network operators, and for space for new connections at the 110/150kV level. The greatest network expansion is envisioned in the Decentral Initiatives and National Leadership scenarios, of approximately 955 km in route length; about a 22% increase in the number of kilometres currently covered by the HV grid in 2023.

- The growth in offshore wind power connections also requires space on land. Each 2 GW offshore wind power connection will be connected to the 380kV grid, distributed across multiple station locations. The converter stations, needed to convert the direct current into alternating current, should be located near the respective 380kV stations. A converter station requires a surface area of around 6 hectares (= 0.06 km^2). The prediction is that between 2030 and 2050, a minimum of 50 hectares (= 0.5 km^2) up to a maximum of 90 hectares (= 0.9 km^2) will be needed for all the converter stations distributed throughout the Netherlands. In addition, these connections will require expansion of the 380kV stations, or even a number of new stations. Each converter requires two connection fields. Each field covers a surface area of around 0.2 hectares (= 0.002 km^2). In the maximum scenario, i.e. National Leadership, 32 connection fields are needed, covering a total area of 6.4 hectares (= 0.064 km^2).

- The space utilisation of the national transmission system for hydrogen and green gas in 2050 is similar to that of the current national transmission system for natural gas. Indeed, the development path assumes reuse of existing pipelines and station locations. In the case of new pipelines and stations, the guiding principle is that they should be installed along existing routes and built at existing locations whenever possible.
  The investment costs are low relative to the other energy carriers and production assets.
  The raw materials – mainly steel – do not impose limitations.
  The storage of molecules in 2050 - particularly hydrogen - does have a spatial impact, especially in the subsurface domain. Construction of the caverns needed for hydrogen storage is on the critical path and also leads to temporary additional utilisation in connection with leaching and brine disposal. The spatial impact can be reduced if the hydrogen can be stored in empty gas fields or in salt caverns offshore, or in existing caverns in Germany.

- The infrastructure for CO_2 transmission, which may be developed depending on the scenario, will mainly follow the existing routes for pipelines. The extra space utilisation is minor therefore. The development of the heat grids is a different story: the transmission infrastructure from the heat source to the point of demand basically involves new routes, and distribution in the districts requires excavation work in many of the streets, which obviously involves temporary space utilisation.

- The indicative space requirement for solar farms and wind power differs between the scenarios. For offshore wind it ranges from 3,800 to 7,200 km^2, for onshore wind from 1,250 to 2,500 km^2 and for solar farms from 350 to 580 km^2. The indicative space requirement varies from publication to publication and depends largely on exactly which key indicators are used. These key indicators are continuing to evolve as time passes. This must be taken into account when making comparisons with other space requirement calculations – now and in the future.

- The installation of new low-voltage and medium-voltage cables requires between 260 and 330 km^2 of additional space, depending on the scenario. Between 80,000 and nearly 105,000 kilometres of cable must be buried in the soil. That is equivalent to between 55% and 75% of the total length of all the streets in the Netherlands. On every working day from now until 2050, 12 to 16 kilometres of new cable must be laid. That work obviously goes hand-in-hand with unavoidable nuisance. Some of the routes are complex and also often require modifications to other infrastructures, such as those for telecommunications and water.

- The additional above-ground space requirement of regional network companies for the various station types is 4 to 6 km^2 (800 to 1,200 football fields) of which – in most scenarios – about 1.2 km^2 are needed for transformer stations. In the vast majority of cases, these are locations in the built environment – close to the consumers. Finding this space makes these grid expansions in a densely populated country like the Netherlands a very difficult task. Most of these areas are urban, and, on average, the work involves adding a third transformer station for every two existing transformer stations. It is essential to start looking for this space now, together with the municipalities involved and other stakeholders, in order to continue facilitating developments in the urban environment.

- The total space requirement for flexibility resources is extensive. Assuming the use of today's technology, the large-scale batteries in the scenarios will require between 23 and 33 km^{2}of space, an area similar to the size of the municipality of Haarlem, which is about 32 km^2 (built-up area plus outskirts). This is relatively sizeable compared to infrastructure with similar space requirements in terms of location and use of space. Compared to the space requirements for the new 110/150 kV substations that are needed, 10 to 20 times more space is required for these flexibility resources. For land-based electrolysers, 3 to 8 km^2 are needed, about 600 to 1,600 football fields. Furthermore, all of these space needs are spread across a large number of locations, which makes the question of the regional fit a key issue. The location of these resources is critical to the energy system's ability to function properly, as they are used for balancing and grid congestion.

The *Programma Energiehoofdinfrastructuur* emphasises timely reservation of the space needed for the incorporation of large-scale flexibility resources. Smaller-scale batteries and electrolysers in the distribution network are also important. This is why it is important to provide tools for choosing locations based on spatial policy, based on the needs of the (local) energy system and with the aim of preventing additional grid congestion.

- The execution challenge for network operators is significant. The projects in the high-voltage grid are primarily related to electrification - especially in industry - and opening up enough capacity for the regional network operators. Most of this work must be done in the period up to 2035. In addition, connecting offshore wind power and the international connections to DC continues beyond 2040. For the regional networks, the task of increasing the electricity distribution capacity will require work to be completed at 2 to 3 times the current speed. The work package must be implemented early on, in the period to 2030/2035. The network operators' investment plans must clarify the extent to which this is feasible.

- For the national gas infrastructure task, the main push in the work appears to be in the period up to 2035. The conversion operation to build the main infrastructure for hydrogen is the most extensive activity in this package. After 2035, the focus of the activities shifts to the offshore hydrogen network.

- The regional gas networks mainly need to be prepared for the feed-in of green gas in the short term. The main push in the work in the regional gas networks comes after 2035, due to conversion to hydrogen and partly for the removal of the gas networks in neighbourhoods that switch completely to electricity or a heat grid. At the same time, the gas network as such will continue to exist, but the connection density and transmission function will decrease significantly.

- It seems almost inevitable that sky-rocketing demand for raw materials, especially certain types of metals, will already lead to scarcity and even physical shortages in the coming years. According to the IEA, the global demand for metals such as copper, lithium, cobalt and nickel will exceed supply even before 2030. This affects all parts of the energy system, but battery systems in particular. It will slow the speed of the energy transition and cause a sharp increase in the associated costs

- The top 10 ranking of critical metals is more or less the same regardless of the II3050-2 scenarios. Lithium – needed almost exclusively for battery systems – tops the list with a requirement in 2050 that varies per scenario up to over a quarter(!) of the global lithium production in 2020. In 2030, that percentage is already 4%. Lithium is followed by dysprosium and neodymium, specifically for wind and also battery systems. For each of these metals, the variation between scenarios is substantial - up to about a factor of 1.5. However, a different technology choice in the area of wind turbines or battery systems has a greater impact and significantly affects demand for the metals.

- The Netherlands must act in collaboration with the EU partners to minimise dependencies on a limited number of source countries. In addition, an immediate start must be made on implementing the four circular strategies in the National Circular Economy Programme. The most important path to reducing raw material usage for the energy transition is also the most obvious: energy saving - i.e. ‘rethink’. And substitution, i.e. ‘reduce’, driven by technological innovation, is also crucial at all steps in the value chain. The combination of the four strategies can result in a drop in demand of 90% or more in the case of some metals.

- The capacities for the manufacture of the materials and equipment required must increase substantially – i.e. electrolysers, power transformers, wind turbine towers and transformer stations – and that too is expected to be a serious bottleneck. Much greater investments need to be made almost everywhere. It is difficult to assess this accurately. The situation differs per semi-finished product and finished product, and the value chains are complex and not at all transparent.

11.2 Energy system costs

11.2.1 Introduction

This section estimates the cost of the energy system associated with each of the scenarios. It first describes the methodology chosen, then the sources of the cost figures and the results for the overall cost. The chapter concludes with some observations on interpreting the results.

Methodology

In general, three types of cost calculation are possible in this study:

- System-related - the integrated system cost perspective;
- Market-related – the marginal cost perspective;
- Societal - the societal costs-versus-benefits perspective.

The nature of these cost perspectives varies, and they can be used to answer different questions. Consequently, the use of these methodologies also varies. Each of these methods has its own strengths and limitations. Following on from the first edition of II3050, the second edition again provides the integrated perspective on system costs. That creates a basis for system choices. This section describes what the chosen methodology entails.

System-related - The integrated system costs method

In practice, when reference is made to the total or integrated system costs with regard to the energy transition, the national costs are usually meant. This involves all the costs of the entire energy system, regardless of who has to pay what part of that bill. The costing methodology used in the Energy Transition Model (ETM) is closely related to this approach. The integrated cost methodology and the national cost methodology do not shed light on the costs to end consumers or other stakeholders. On the other hand, these methodologies do provide a transparent framework for comparison of the national - or integral - energy system costs. When assessing similar scenarios, the cost differences between scenarios can thus be clearly identified.

11.2.2 Cost calculation in the ETM

The scenarios on which this study is based were modelled in the ETM. The costs in the ETM model were updated in the run-up to II3050-1. In addition to the profiles of supply and demand and the consequences for the energy balance, the ETM model provides output for the total annual costs. It takes into account the sum of depreciation costs, capital costs, fuel costs, emission costs and operations and maintenance (O&M) costs. The ETM cost calculation is based on the following principles:

1. Greenfield approach: the ETM method ignores existing assets and investments. Only future investments in assets are considered.

2. Societal costs: in the description of the ETM costing methodology, reference is made to the societal costs of future energy systems. Energy prices for specific stakeholders are not calculated. Taxes, government grants and levies are not considered.

3. Direct costs: the ETM considers only the direct costs of the energy value chain.

4. No inflation: all costs in the ETM are expressed in real terms, and inflation is not taken into account.

5. Straight-line depreciation: all investments are depreciated using the straight-line depreciation method.

In the II3050-2 costing, the cost of the network operators' infrastructure is added outside the ETM model. The total annual costs are the main outcome of the costing methodology in the ETM. These costs are broken down into ten categories: heat, electricity, hydrogen, transmission, fuels, non-energy fuels (feedstock), energy infrastructure, CCS in industry, flexibility and vehicles. A detailed overview of the various cost components by sector is also available. The scopes of this sector-based cost calculation are presented in outline below.

Cost determination

The determination of the integrated system costs for the energy system transition is shown in Table 17.

Table 17: *Determination of the integrated system costs for the energy system transition*

Sector	Source	In scope	Outside scope
Built environment	ETM	Energy technologies for useful demand (such as space heating, lighting, cooling, electricity for appliances)	Household appliances (dryer, vacuum cleaner, washing machine, television, computer, dishwasher and refrigerator), non-household appliances, lighting and cooking
Transport/ mobility	ETM	Assumed additional BEV (battery-powered electric vehicles) and FCEV (fuel cell-powered electric vehicles) costs relative to conventional cars	Other means of transport
Agriculture	ETM	As per the built environment, for cooling and space heating	Business installations
Industry	ETM	Process heat (for steel, aluminium, fertiliser, other chemicals, refineries, food and paper and 'other')	Raw materials and other installations (including data centres); detailed refining processes or chemical processes. Full process revision
Flexibility	II3050 flexibility analysis & ETM	Gas-to-power stations, power-to-gas installations, hydrogen storage, system batteries, power-to-heat, thermal storage, hybrid heat pumps, smart car charging	Costs for curtailment of renewable generation
Infrastructure for CO_2	ETM, supplemented by our own infrastructure calculations		
Energy	ETM	Imported electricity, heat, green gas, biomass, bio-fuels; assumption for imports regarding cost per unit volume (natural gas, coal, oil, fuels, biomass)	
Infrastructure E, G, H_2, H	II3050 infrastructure analyses and network operators	CapEx investments, Network O&M	

11.2.3 Costing methods conclusion

The national cost methodology and related integrated system costs were used for this exploratory outlook of the energy system. This approach identifies the integrated costs for the Netherlands as a whole. In respect of the infrastructure calculations, our own analyses in II3050-2 take priority and the costs have been taken from the Basic Document drawn up by the network operators ('Basisdocument voor de energie-infrastructuur' [Basic Energy Infrastructure Document], NBNL). Since this document has not been updated recently, the maximum values were chosen to ensure a realistic estimate.

In line with usual practice, the boundary of the national energy system has been taken as the system boundary. So net imports are included as a cost component. The total costs of the system change have been mapped, as explained below in the section on the results. It is also important that the results are carefully interpreted in line with the nature of the scenarios.

11.2.4 Further processing of the costs in II3050-2

As described above, the energy system costs have been taken from the scenarios in II3050-2, as modelled in the energy transition model. There is one exception: the infrastructure costs. In phase 2 of II3050-2, close attention was given to the impact of the scenarios on the energy networks. In the analysis, after the bottleneck phase, proposals for infrastructure solutions were put forward. These solutions have been worked out as final pictures with the associated infrastructure. In combination with key cost figures from the Basic Document, this provides information about the infrastructure costs. The annual upkeep costs and operation and maintenance costs are included in the numbers. This was done for the energy carriers electricity, methane and hydrogen (both in gaseous form), heat and CO_2. CO_2 transmission only applies in the European Integration and International Trade scenarios. For the regional and national network operators, calculations have been made for different time periods, 2023 to 2050 versus 2035 to 2050, because of the different starting point of the analyses, i.e. 2023 and 2035, respectively. Allowance has been made for this in the cost calculation.

Results

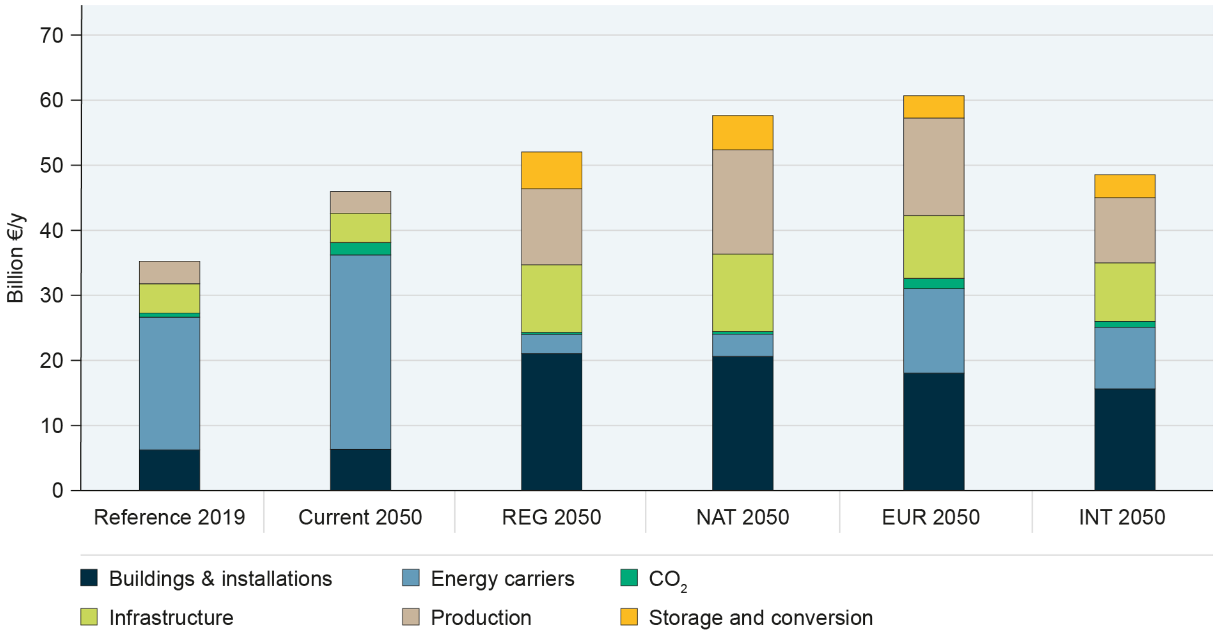

Figure 71: *Total annual energy infrastructure costs for each scenario of II3050 edition 2*

Figure 71 shows the annual, national cost of the energy system infrastructure in the different scenarios: first, the current composition of costs (REF19) and, next, the current system in 2050 (HUID50). The fuel cost trends and CO_2 prices, according to the IEA 2021 report, are included The *Stated Policies* scenario has been taken as the starting point here. This scenario is not the same as the 'current system'. It does aim to describe a scenario based on current policy, without the additional sustainability goals. The fuel costs and the CO_2 price were adopted from this scenario and modelled in the ETM model. Allowance was also made for expiry of the CO_2 exemptions in 2050. This scenario is very sensitive to import costs. In 2022, as a result of the turmoil in the energy market, we saw energy costs increase by a factor of 5. If that were modelled here, the picture would look very different.

In the four climate-neutral 2050 scenarios, the costs of infrastructure are higher than the current energy costs. The differences in total costs between the scenarios are limited; however, the composition of the costs does vary widely between the scenarios. The costs of infrastructure and flexibility resources - storage and conversion - are relatively modest at 20% to 30% of the total energy system costs. The main costs are principally associated with modifying buildings and installations - these costs are highest in the Decentral Initiatives and National Leadership scenarios - and with the production assets- highest in the National Leadership and European Integration scenarios. In addition, in the European Integration and International Trade scenarios, the costs for energy carriers are significant due to the import of energy carriers. The latter costs are sensitive to price fluctuations in the international market.

Buildings/installations:

The buildings and installations category includes all heat production costs, excluding the fuel costs. Insulation costs in the built environment are also included. Possible additional costs related to electric mobility, such as investment costs, are also included in this category.

Storage and conversion

- H storage: the cost of storing heat. The scenario results of the ETM model were used here.

- H2 storage: the cost of storing hydrogen. The values for this are based on an internal analysis.
- Flexibility: the cost of batteries and flexibility resources for electricity-to-hydrogen conversion with electrolysis, system batteries for power-to-power and the gas-fired power stations, peak power stations and large power stations. In this version, this is modelled in the ETM. This differs from II3050-1, due to an update of the ETM model.

Production assets

All costs for domestic production of electricity and dedicated (blue) hydrogen, excluding fuel costs. The cost of CO_2 allowances from the ETS is not included, as this cost is a tax.

Energy sources and imports

The costs of all (primary) energy carriers. In 2050, this consists almost entirely of imports, except for a limited amount of local biomass, based on the World Energy Outlook 2020 cost overview (International Energy Agency, 2020).

Infrastructure

- Heat infrastructure: the costs for heat grids, based on our own calculations.

- G (gas) and H2 (hydrogen) infrastructure: the costs for the gas grid and the hydrogen grid, both onshore and offshore, based on our own calculations.

- E (electricity) infrastructure: the costs for the electricity grid, both onshore and offshore, based on our own calculations.

- Other network operators' costs: the annual costs include depreciation and the costs of the organisations of the various network operators. This was estimated in 2019, based on an analysis made by the network operators. It has been assumed that these costs will remain the same. On the one hand, there is an increase in assets, and on the other, increasing efficiency. As a forecast of OpEx development is not part of the study, it has been kept at the 2019 level.

- CO_2 networks and CCS: the additional investments for carbon capture plants at power stations and hydrogen stations, the costs of CO_2 infrastructure and the cost of storing CO_2. The costs for infrastructure, based on our own calculations, have been added to the costs from the ETM model. The cost modelling method used in the ETM model is described in the ETM documentation. The scenarios that were modelled and the results can also be found here.

11.2.5 Detailed analysis of the infrastructure costs

This section looks at the investment costs of the assets that need to be built (new) or expanded (existing). They are expressed as the annual costs, because that ties in with the costs that are consistent with the ETM cost system. First, the outcomes are shown for gas, then for electricity, and finally for heat and CO_2 networks. A discount rate of 3% and a depreciation period of 40 years were used for all investment costs.

For the period to 2030 and to 2050, it has been calculated that network operators need to invest between 5 and 7 billion euros annually, depending on the scenario. In all scenarios, the investment for expanding the electricity grids is the greatest. The outlier here is the National Leadership scenario, in which an average of nearly two billion euros per year is earmarked for offshore electricity grid construction. The hydrogen pipelines are additional to this. In the National Leadership scenario, relatively large investments need to be made in the construction of heat grids to provide heat to six million home equivalents, both households and buildings, in 2050.

As described earlier in this report, the electricity system may need to be ready earlier than 2050, in the period from 2035 to 2040. This means that investment costs will have to be incurred mainly in the first period.
This applies particularly to the part that is linked to the CO_2-free electricity system, for production. The part linked to the electricity demand for heat supply and mobility, for example, will also have an effect in the period from 2040 to 2050.

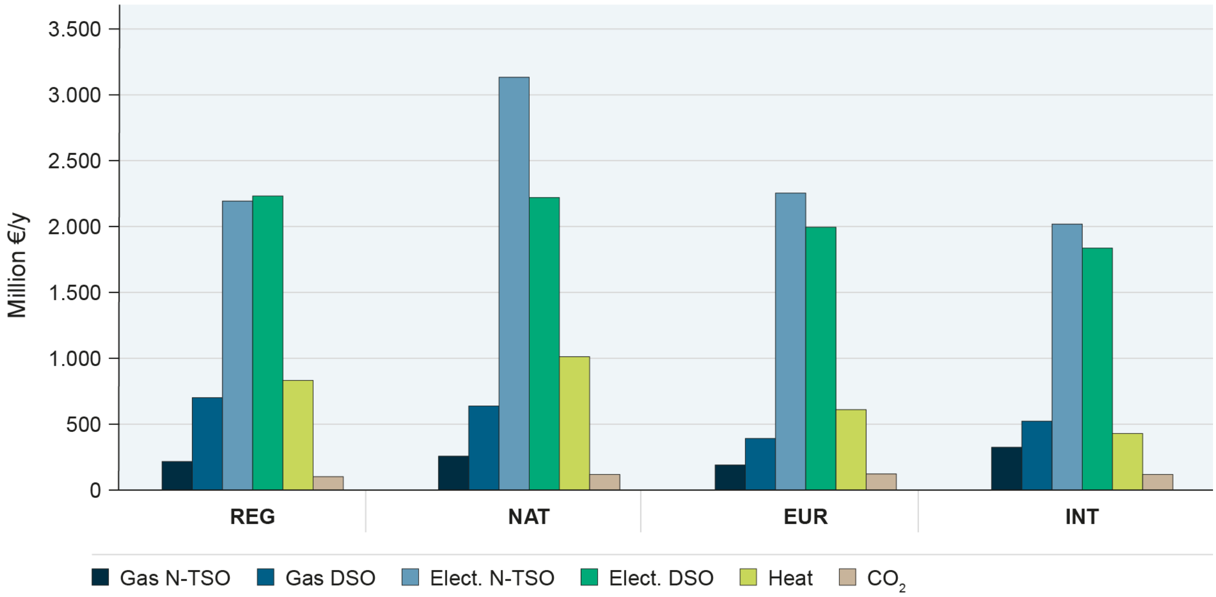

Figure 72: *Annual infrastructure investment costs*

National gas infrastructure operator

The cost of modifying the required national hydrogen infrastructure between 2035 and 2050 is relatively small. The main cost items are the hydrogen compressors, which are roughly the same in all scenarios. In addition, the construction of hydrogen pipelines and the installation and conversion of gas receiving stations are major cost items in three of the four scenarios. The investment in offshore hydrogen pipelines is the largest cost item. Allowance is made for about 400 km of HPGG pipeline with compression, depending on the capacity needed.

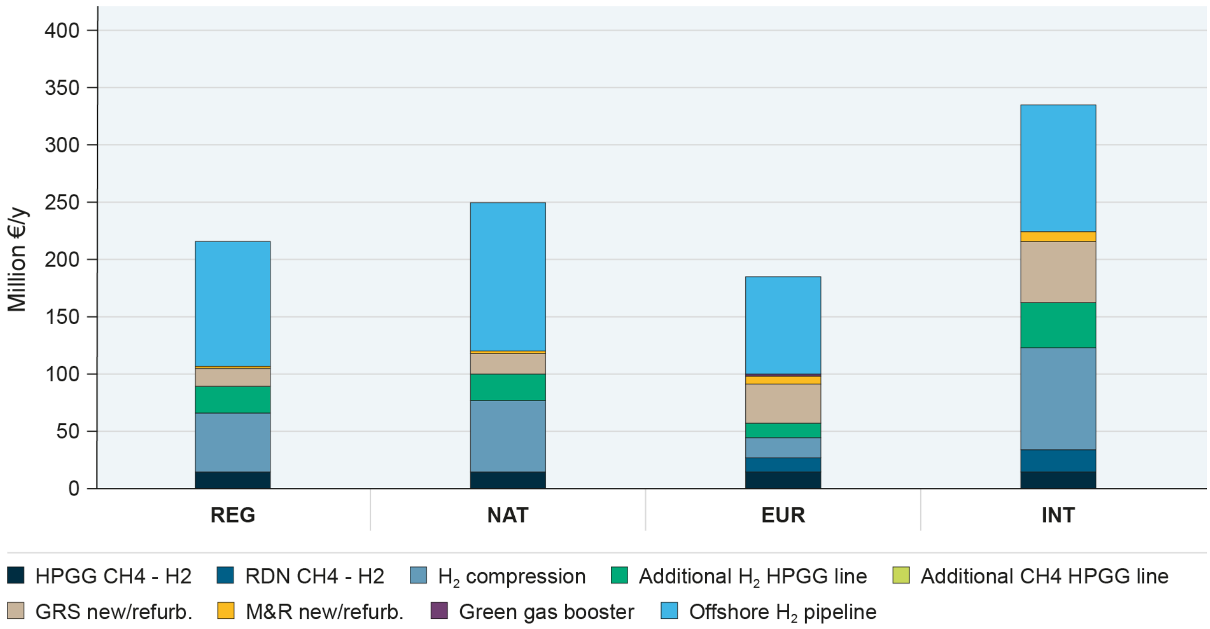

Figure 73: *annual national operator costs for gas.*

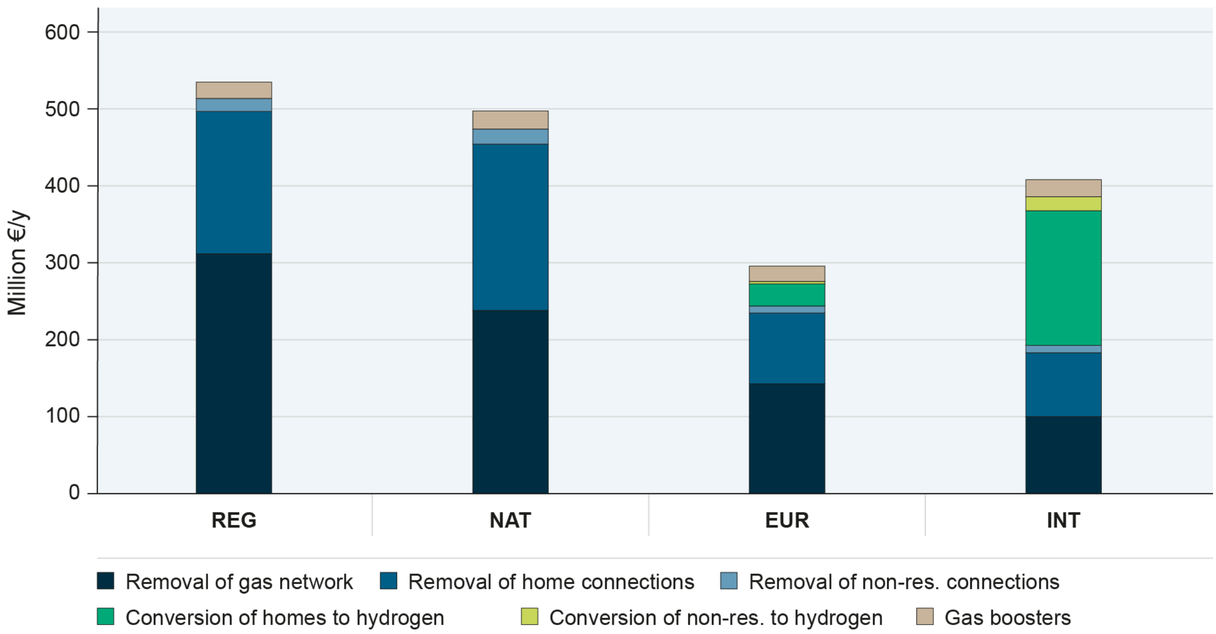

Figure 74: *annual regional operator costs for gas*

Regional gas infrastructure network operators

The regional network operators managing the gas infrastructure foresee a conversion of the existing natural gas network to a hydrogen network for the built environment. In cases where the built environment no longer uses gas for heating, the cost of removing the gas network is included. As shown in Figure 74, these costs are huge. Enormous savings can be made by deciding to take the pipelines out of service first and then removing them at a convenient time.

National transmission system operator for electricity

TenneT, the Dutch national transmission system operator, faces an extensive task. In the calculations, we examined the necessary modifications between 2035 and 2050. This assumes that the Investment Plan for 2035 has been implemented, including the projects that are currently still in a study phase, but scheduled to be in operation by 2035.

The costs relate to investments in and management of the 220-380 kV and 110-150 kV onshore infrastructure and electricity infrastructure for connecting offshore wind farms. These include offshore platforms for collecting renewably generated energy and the cables that run to the coast. Figure 75 clearly shows that the investment costs in the national infrastructure for electricity are highest in the National Leadership scenario. This is mainly due to the large amount of installed offshore wind power. The costs for the main distribution stations (MDS) are included in the regional network operators' costings, the costs incurred at the national network level only include the 150 kV or 110 kV connections that are required. All the other MDS costs, transformer and IV or MV installations, are included in the regional costing.

The costs in Figure 75 include only investment costs and are a very rough estimate. The scenarios are uncertain. Moreover, the actual costs are highly dependent on the technical implementation and technological development, among other things, which may also result in a cost reduction. The impact of these factors on the costs cannot be estimated accurately at this time.

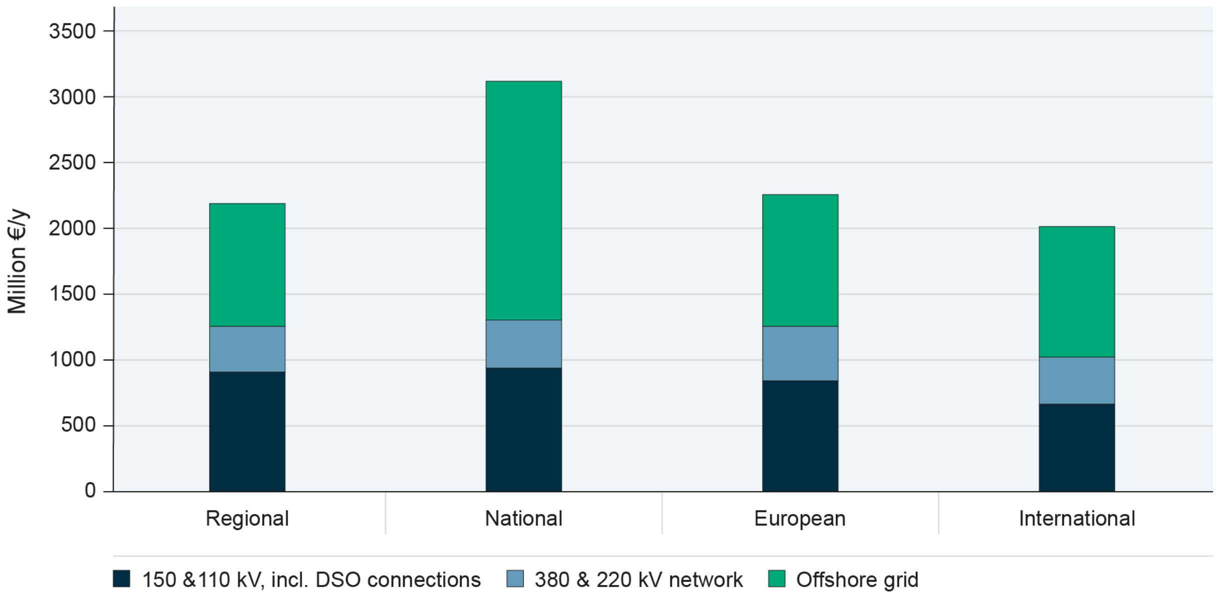

Figure 75: *annual national network operator costs for electricity*

Regional transmission system operators for electricity

The Decentral Initiatives and National Leadership scenarios assume local or national generation of energy, primarily in the form of wind and solar power. Due to this assumption, these scenarios place greater demands on the electricity grid than the European Integration and International Trade scenarios. The latter two scenarios focus more on gas - hydrogen and green gas - as an energy carrier. In the case of the first two scenarios, the main focus is on local sustainable energy generation in the form of solar and wind power. This is reflected in the level of investment in the regional grids. A relatively large part consists of the modifications to and new construction of the main distribution stations (interconnection point with TenneT).

Interestingly, the different scenarios do not show major differences in the MV and LV cable-laying work that will be needed. The numbers of MV and LV cables are similar. The differences in cost can be attributed to differences in the unit price, materials and construction approach. Those costs are a factor of 2.5 higher for an MV cable than for an LV cable.

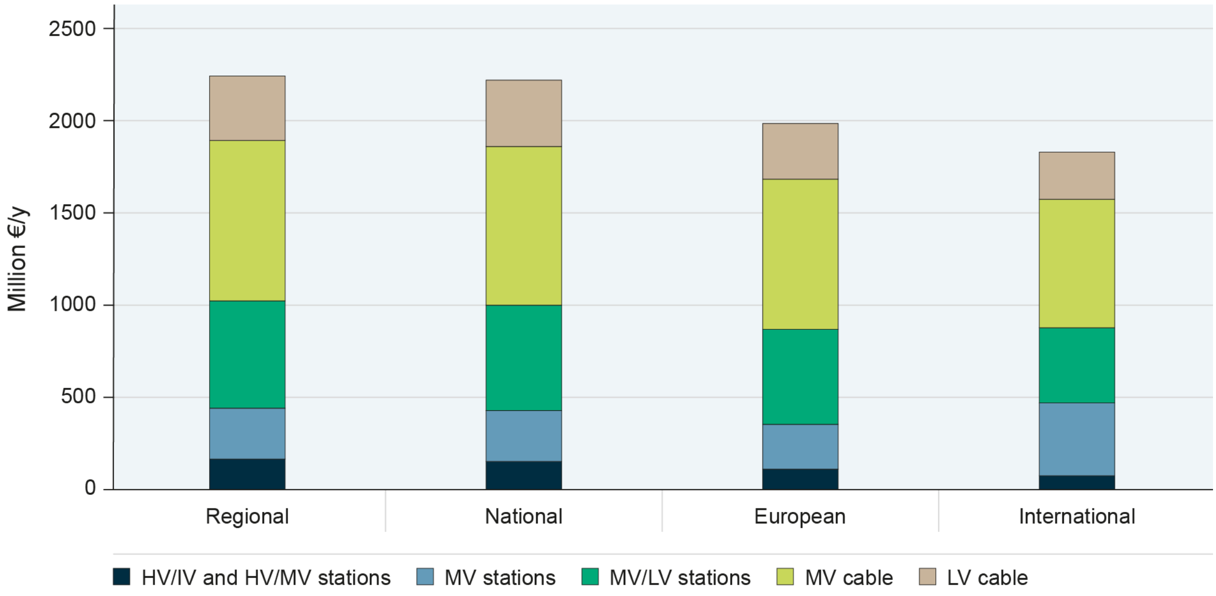

Figure 76: *annual regional network operator costs for electricity*

Heat grids

In respect of large-scale heat transmission, the following cost estimates apply in each scenario. These estimates include pipelines, pump stations, pressure maintenance systems and heat distribution to end-user consumption points. The costs for laying a distribution network from the source are not yet included. These expenses are usually borne by the heat supplier rather than the heat transmission company. The stated distances and costs are per doublet - supply and return are therefore not counted separately, but seen as a unit.

CO_2 networks

The European Integration and International Trade scenarios include a CO_2 pipeline network of about 250 kilometres in length: 75 km for Maasvlakte-Zeeland and 175 km for Maasvlakte–Sittard. This is a large-diameter pipeline (36” - 47") with a capacity of roughly 5 Mtons at the assumed 40 bars pressure. To achieve the level of compression required, one compressor will handle the first route and two compressors per 100 km will be installed to handle the circuit to Sittard. That adds up to a total of five compressors. Allowance is made for these infrastructure costs in the total CO_2 costs and in the overall costs.

11.3 Energy system spatial requirement

11.3.1 Introduction

The energy system of 2050 requires additional space - much more space than the fossil-based system.
Solar, wind, the extensive grid infrastructure and the various flexibility resources must be assigned a geographical location, very quickly in some cases, in a climate-neutral Netherlands. The associated choices for assigning

scarce space in the Netherlands will largely be made in the coming years. Much of the energy system change must be planned now.

The space needed for all the components of the new energy system must be available in good time. Failure to meet this requirement will delay the energy transition because one or more of the indispensable components, for generation, storage, conversion and transportation, cannot be built. This is why II3050-2 maps out the long-term space requirements of the future energy system. It is important that these pictures of the space requirements are incorporated in planning and spatial programmes and processes - the MESP, RES, local environmental visions, NOVEX. It is also important to target this aspect in the NESP, Energy Visions/provincial multi-year energy and climate infrastructure programme (pMIEK), and the national climate and energy policies so that the required space can actually be reserved. This allows network operators to plan, invest and build more effectively and at a faster pace, meaning that the Netherlands will be able to meet its climate goals.

II3050-2 clarifies how much space is required at the national and provincial level for solar farms, wind power, flexibility resources and the grid upgrades needed for a balanced energy system. To estimate the space requirements for grid upgrades, TenneT, Gasunie and the regional network operators have each produced their own analyses.

The sections quantify the space requirements in km^2 or hectares, or equivalents such as the numbers of football fields, by way of illustration - and describe how they were determined. Section 11.3.2 starts with a brief reflection on the space requirements of the new energy system. The goal is to identify different aspects or qualities associated with the space requirements and establish a relationship with existing programmes and projects. Appendix G visually juxtaposes the overall picture of the space requirements for the four II3050 scenarios.

11.3.2 The space requirements in perspective

The space requirements are expressed in km^2 or hectares, but the corresponding figures must be considered in context. Two aspects are important here:

1. The nature of the claim to space varies - not all claims are the same.
2. Space has different qualities - not all spaces are the same.

The first aspect - in addition to blending in as required by current laws and regulations - is affected by possible function combinations, which lead to above-ground restrictions. This is one of the three assessment principles applied in the MESP[45]. For energy infrastructure, these include:

- In the case of pipelines, the above-ground area must be accessible. The construction of roads or paths and laying other hard surfacing is not allowed without a permit. Potentially dangerous activities such as digging, pile driving, deep ploughing and placing or removing deep-rooting plants are not allowed in the pipeline's controlled area.

- The limitations associated with hydrogen storage are minor. A small area of the land above the caverns is not available because of the installations needed for compression and gas treatment and because of valves.

- In the case of high-voltage power lines, there are prohibitions on carrying out work and/or erecting structures, and restrictions on working with, for example, cranes and pile drivers in the vicinity. Electromagnetic fields can lead to restrictions on the possible designated use, such as residential use.

[45] *Draft Programma Energiehoofdinfrastructuur (PEH)* (2023)

- In the case of cables, the land above should be kept unobstructed and any hard surfacing for streets should take the form of individually removable paving bricks or pavement slabs. Proximity to tree roots should be avoided to prevent damage.

- Distribution stations, electrolysers and system batteries: dual function use is not possible, or is not a logical choice in view of the intensive use of space by vulnerable installations and contours for safety, electromagnetic fields and noise/nuisance. Smaller stations and batteries can be placed indoors as appropriate.

- Wind turbines are sometimes difficult to combine with other functions due to safety and environmental requirements. But, once installed, there are hardly any restrictions on agricultural activities and any existing road and railway infrastructure, for example. In the case of solar farms, dual function use in combination with agricultural activities is possible but is not always applied by a long way. Solar PV is also sometimes installed on inland waterways.

The second aspect is also obvious: there is a difference between urban and rural areas, coastal areas and, for example, port or industrial areas. Space is scarce in the Netherlands, but at some locations there are more opportunities for incorporating energy infrastructure than at others, judged purely by square metres. Regarding spatial qualities: the space needs of the energy system and possible solutions for meeting those needs are addressed in a number of programmes and studies. The MESP summarises this as follows: ‘The National Spatial Planning Vision (NSPV) sets out central government's guidance framework for developing the living environment in the Netherlands. In the face of various spatial challenges such as climate change, housing and mobility, the NSPV sets out an integral vision of the future design of the Netherlands, and in doing so, central government also provides guidance for regional choices. The various tasks are further elaborated in a number of thematic programmes, including the MESP. As a result, the NSPV provides a roadmap for strengthening environmental quality in the Netherlands. Through the NOVEX programme, the national and regional spatial tasks are explored for each province, and government authorities at all levels work together on a plan for the spatial organisation of the Netherlands. Areas where many tasks converge have been designated as focus areas; so-called NOVEX areas. In the NOVEX area approach, central government works closely with regional governments, market players and other stakeholders to plan the space needed for energy in the industrial parks for the medium and long term. The ‘Mooi Nederland’ aesthetics programme aims to make spatial quality central to the spatial implementation of the various tasks. The outcomes of the NOVEX and ‘Mooi Nederland’ programmes will lead to new national spatial policy: the revised and more detailed NSPV, expected in 2024. The MESP serves as input for this.’

Finally, PBL (the Netherlands Environmental Assessment Agency) recently published the 2023 Spatial Outlook, which explores the future spatial planning of the Netherlands from various normative perspectives. Four normative scenarios are worked out in detail: policy scenarios with different spatial options, based on different societal visions, which respond to spatial tasks from their own inherent value orientation. It is a qualitative study that explores what spatial choices policy-makers can make to achieve visions of the future that are considered to be desirable from different societal perspectives. The four scenarios in II3050-2 and the four normative scenarios presented in the Spatial Outlook are not related to each other, cannot be mapped onto one other, and serve different purposes.

11.3.3 Rough picture of the space required for TenneT's infrastructure

Assumptions and methodology

For this analysis, it is assumed that the existing investments for grid upgrades identified in the 2022 IP are realised. For the spatial requirements analysis, a distinction was again made between the 220/380kV grid and the 110/150kV grid.

In the case of the 220/380kV grid, the mitigation measures needed to resolve the bottlenecks in the different scenarios were considered. In principle, the infrastructure for the 220/380kV network is constructed above ground. Where there is a need to provide additional connections, it is assumed that they will be placed next to existing connections and next to those expected in the period from 2030 to 2035. Possible new connections for resolving bottlenecks were not considered in this study. The need for space was determined based on the task in the MESP: for an overhead high-voltage line, a route 100m wide is assumed. This study does not consider the space requirements for possible 220/380kV stations.

In the case of the 110/150kV network, the additional space requirements consist largely of two aspects:

- The first aspect is the space for new high-voltage stations, for increasing the transmission capacity towards the regional network operators. The number of new high-voltage stations was determined based on the regional need for transformer capacity and is further detailed in Chapter 7. The indicative space utilisation follows in a later section.

- The second aspect is the space for new connections at the 110/150kV level to connect the new high-voltage stations.

In the 110/150 kV grid, new connections are usually installed underground, unlike 220/380 kV connections. In terms of the space requirement, a route width of 35 metres has been assumed[46]. This study did not consider the following: possible alternative routes for the connections to resolve bottlenecks, further splitting of pockets through new connections to the 220/380 kV grid or large-scale sustainable generation in regional areas, or directly grouped connection to the 220/380 kV grid.

Space requirement for the 220/380 kV network

For the 220/380 kV network, an analysis was performed to see what grid upgrades could be used to mitigate the bottlenecks. As indicated in Chapter 5, the analyses show that a grid upgrade between Noord-Holland and Zuid-Holland provinces and the south of the Netherlands is necessary, particularly to facilitate the growth of offshore wind. The upgrade of the connection between Ens and Hengelo ties in with the grid upgrade between Diemen and Ens, which is already under preparation. This establishes a strong connection between the Randstad and Germany via the north side of the national ring. The assumption for this study was that the grid upgrades identified in the2022 IP publication have actually been implemented. To determine the number of route kilometres of additional connections to be built, it was assumed that they would be placed adjacent to the existing connections. Possible new connections - connecting two previously unconnected stations - to resolve bottlenecks were not considered in this study.

In the current situation, there are approximately 1,500 route kilometres of 220/380 kV line connections.

The additional spatial requirement varies between scenarios and depends on the amount of offshore wind and choices regarding the size and location of flexibility resources. But in all scenarios, the need to upgrade the corridor between Noord-Holland and Zuid-Holland provinces and the south of the Netherlands is clearly apparent.

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[46] This includes the laying zone (see also the Draft PEH) and differs here from NBNL's Basic Information Document and the first edition of II3050, where the calculation was based on 10 metres (without the laying zone).

Although the space requirement is a fraction of the surface area of the Netherlands, finding that space is a difficult task. This is because the space must be found in relatively small search areas. The choice of search areas is limited by the need to connect to existing and planned infrastructure, and other considerations. All the new infrastructure must also be blended in with the existing built area in densely populated parts of the country. Thorough consultation with the relevant authorities, agencies and residents is crucial here in order to engender support for the concrete implementation of the space requirement.

Space requirements for bringing offshore wind power to land

The growth in the number of connections for offshore wind power also requires extensive space on land. The government's targets indicate that another 16 to 31 GW of connections for offshore wind power must be put in place between 2030 and 2050. For this purpose, TenneT is developing a standard platform concept that will be connected to the 380kV grid via a 2 GW direct-current connection. So a total of 8 to 16 of these connections are necessary. This has two consequences:

1. Direct current must be converted to alternating current. This is done in a converter station. Depending on the scenario, 8 to 16 new converter stations will be installed after 2031, spread across the Netherlands at various locations. These converter stations should preferably be located near several 380kV stations. A converter station requires a surface area of almost 6 hectares. The prediction is that between 2030 and 2050, a minimum of 50 hectares and a maximum of 90 hectares will be needed for all the converter stations distributed throughout the Netherlands.

2. Additional connection fields are also needed at the 380kV stations, two connection fields per converter. Station extensions or possibly new 380kV stations are require to facilitate the connections. Each connection field covers a surface area of around 0.2 ha. In the maximum scenario, 32 connection fields are needed covering a total area of 6.4 hectares. An entirely new 380kV station requires an area of about 20 hectares.

Space requirement for the 110/150kV network

New connections at the 110/150kV level are needed to connect the new high-voltage stations. It is assumed that the high-voltage stations cannot be built directly under or adjacent to the existing connections. On average, each new station requires a connection with a route length of 10 km.

Table 18**Table** quantifies the indicative space requirements in terms of the route kilometres and surface area in km², calculated based on a route width of 35 m. The final route length in practice depends on the actual technical implementation.

Table 18. *Indicative space requirements for new 110/150kV connections*

Additional route length required in km (area in km²)	Current situation	Regional	National	European	International
110/150kV grid	4400	955 (33.4)	955 (33.4)	720 (25.2)	555 (19.4)
110/150kV grid (% increase)	4400	22%	22%	16%	13%

The indicative lengths and areas are not all that different for the Decentral Initiatives and National Leadership scenarios. Fewer high voltage stations are required by the regional network operators in the European Integration and International Trade scenarios. This results in a smaller number of route kilometres for the linking connections.

11.3.4 Rough picture of the space required for Gasunie infrastructure

Assumptions and methodology

The space requirements for the hydrogen and methane infrastructure were determined based on the results of the bottleneck analysis of the national gas grids, the HPGG high-pressure grid and the RTP medium-pressure grid, in Chapter 6. The investments mainly involve converting existing natural gas pipelines to use for hydrogen, laying new pipelines for hydrogen and installing hydrogen compression at various locations.

Part of the hydrogen infrastructure in 2050 consists of newly constructed pipelines. These will be placed almost entirely in currently reserved pipeline zones - in many cases zones identified in the Structure Vision for Pipelines - running parallel to existing pipelines. This does not change the overall corridor width; usually 70 m for SVP zones.

The total space utilisation in km^2 for HPGG pipelines can be calculated by multiplying the length in kilometres of a pipeline in a given zone by 0.07 km. A pipeline stack with several parallel pipelines in a 100 km route thus covers a total area of 100 x 0.07 = 7 km^2. This space cannot be built on, or not fully built on, but normal use for arable and livestock farming, for example, is often possible. In other words, the effective space utilisation is smaller than the calculated space utilisation.

Hydrogen compression is in principle planned in locations where natural gas compression is currently taking place. The possibility that hydrogen compression will need to be provided at some new locations cannot be ruled out. The space utilisation depends on the installed compression capacity, which determines the size of the building for the installations, the grounds and the fencing.

In the case of the RTP, the situation is different. Most RTP pipelines are not installed in a national pipeline corridor. The Dutch Decree on the External Safety of Pipelines applies to those RTP pipelines, covering a distance of about 6,000 km in total, and this decree states that a four-metre zone must be reserved on both sides of the natural gas pipelines. For other substances, including hydrogen, this zone is five metres on each side. So an RTP pipeline that is converted to hydrogen needs an extra two metres in width.

HTL figures

The investments in the high-pressure grid between 2023 and 2050 mainly involve making existing natural gas pipelines suitable for transporting hydrogen. No new space needs to be claimed for this purpose. Part of the HPGG for hydrogen in 2050 consists of newly constructed pipelines. These new pipelines also do not lead to additional space utilisation because they can be laid in existing pipeline corridors. The new hydrogen compressors that need to be installed will only lead to an additional claim on space if they are built in new locations. The space required for a new station is limited, but does depend on the compressor power installed.

Because of the decreasing role played by methane in the energy system, no new pipelines for methane need to be built, except perhaps the occasional new connecting pipeline for green gas production. We assume that the numbers of these pipelines will be so small that the associated space utilisation can be ignored.

Figure 77: *New H2 pipelines in 2050*

Table 19: *Indicative distance in km of the new H2 pipelines in the HPGG from 2035. This does not lead to extra space utilisation.*

New H2 pipelines *(km)*	Situation in 2035	Regional	National	European	International
HPGG H_2	approx. 1,100 km*)	150km	150km	80km	260km
HPGG CH_4	approx. 5,200 km	0	0	0	0

*) Onshore network. Construction of the offshore network starts from 2030 and increases to about 400 km in the run-up to 2050. This does not lead to further space utilisation on land.

Table 20: *Indicative number of new hydrogen compression locations from 2035 (space utilisation < 0.01 km^2).*

New H_2 compressor locations *(number)*	Situation in 2035	Regional	National	European	International
HTL	0	1	1	1	2

Because the calculation methodology links neighbourhoods to points in the future hydrogen network via the shortest distance, it does not provide information on the required hydrogen connection pipelines. Reuse of an existing gas connection is not possible in all cases. While connection pipelines tend to be short, a few kilometres at most, when dozens of new connections are involved, the total length can still be considerable. If we assume a distance of 200 km and that the connection pipeline will be located approximately 1 m from the existing natural gas pipeline, the additional space required is 200 x 0.001 = 0.2 km^2.

RTL figures

In the International Trade scenario, substantial hydrogen demand develops in the regional grids after 2030. Regional hydrogen demand also develops in the European Integration scenario, although to a lesser extent. It is not inconceivable that certain smaller industries in cluster 6 will be given a direct, new connection to the national hydrogen network. Part of the current RTP can be converted to hydrogen to satisfy the remaining demand in the regional grids.

Even if dozens of small industries are given a new connection of this type, the additional space utilisation is small, less than 1 km^2; a pipeline of 1.5 km in length per connection, in a 10 m wide corridor. The reuse of RTP pipelines is roughly estimated to involve up to 2,000 km in the European Integration scenario and 3,000 km in the International Trade scenario. So an additional two metres of space must be reserved alongside these pipelines, equating to 4 or 6 km^2 in total respectively. The outcomes for the additional space utilisation are specified in Table 21 below.

Table 21: *Indicative additional space utilisation for RTP pipelines transporting H2. For the European Integration and International Trade scenarios, the space utilisation specified includes new connections for cluster 6 industry.*

Extra requirement *(km^2)*	Current situation	Regional	National	European	International
RTL	approx. 5,700 km	0	0	< 2,000 km (< 5 km^2)	< 3,000 km (< 7 km^2)

11.3.5 Rough picture of the space required for regional network infrastructure

The required upgrade of the grid infrastructure of the regional network operators is described in Chapter 7.[47] The associated space requirement is a direct consequence of the required grid upgrades. This is calculated based on the average length and surface dimensions per asset type identified in Netbeheer Nederland's ‘Basic Information on Energy Infrastructure’ document.

For the 110/150kV network (connector points with TenneT), consideration has been given to the new station construction activity that is expected to be needed to resolve the overloads at the connector points in the scenarios without adding system flexibility. The assumption here is that an overload of less than 80 MVA - worst case - or less than 160 MVA - best case - can be accommodated by expanding the station within the currently available physical space at the station location. If the overload exceeds 80 MVA or 160 MVA respectively, a new station must be built at a new location in the vicinity.

[47] In the case of the gas infrastructure, the space requirement is limited to the installation of boosters for green gas; this is negligible. Removing parts of the gas network does not lead to a space claim. No calculations have been made for making parts of the regional gas grid suitable for hydrogen, and it is currently estimated that no significant space claim follows from this either.

To estimate the space utilisation for the underlying grid, the required infrastructure was divided into two types of assets: underlying substations and medium voltage stations - transformer stations. The cables are for low voltage (LV) and medium voltage (MV).

Results

Figure 22 indicates the above-ground space requirement. In respect of the transformer stations, in the vast majority of cases these are locations in the built environment - close to the consumers. This involves a total area equal to between 170 and 240 football fields - for the International Trade and Decentral Initiatives scenarios, respectively. That space breaks down as an average requirement of 22.5 m^2 of land per MV/LV station in urban and inner city areas.

Table 22: *Above-ground space requirement for regional network operators across all of the Netherlands*[48].

Voltage level	Regional	National	European	International
110/150kV stations	1.8 – 3.7 km^2	1.8 – 3.5 km^2	1.0 – 2.4 km^2	0.6 – 1.6 km^2
Underlying substations	1.9 km^2	1.9 km^2	1.7 km^2	1.6 km^2
MV/LV stations	1.2 km^2	1.2 km^2	1.1 km^2	0.8 km^2
Total	4.9 – 6.8 km^2	4.9 – 6.6 km^2	3.8 – 5.2 km^2	3.0 – 4.0 km^2

The space utilisation for the 110/150kV stations by province is shown in Figure 78. The forecast space utilisation is largest in the Decentral Initiatives and National Leadership scenarios. This is because of the large amount of onshore wind and solar farms - as well as the peak-prevalent nature of these technologies - creating the heaviest load for the 110/150kV stations.

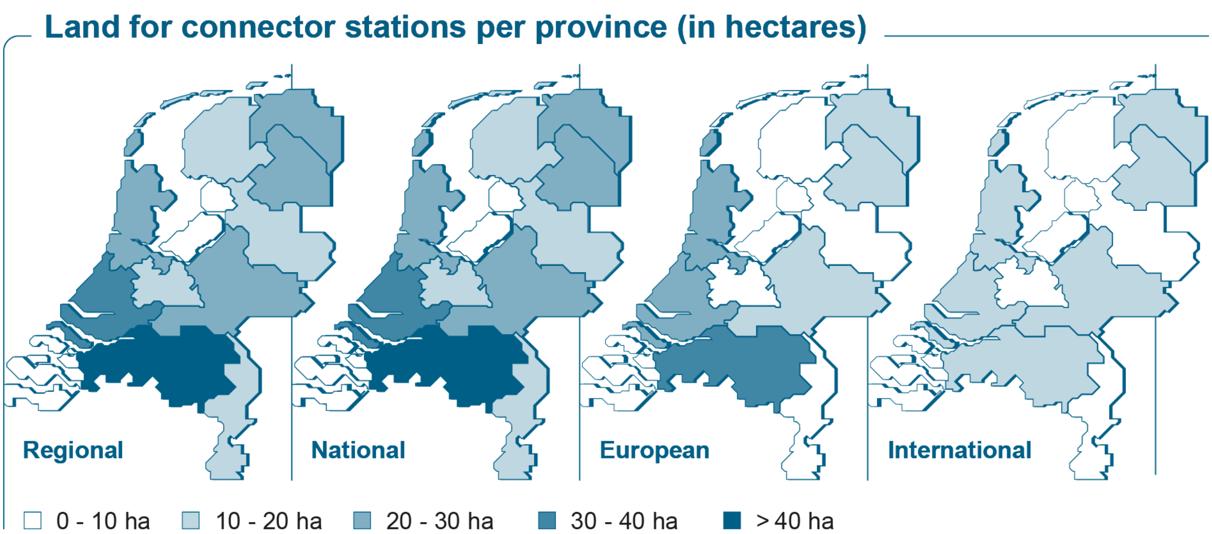

Figure 78: *The split across the provinces of the space requirement for 110/150kV stations*

The underground space requirements are significantly higher than the above-ground space requirements. Between 80,000 and 105,000 km of cable must be laid during the next 25 plus years. That is equivalent to about 55% to 75% of the total length of the streets in the Netherlands and means that on every working day between

[48] Relative to II3050-1, the MV/LV stations are shown separately. In II3050-1, the MV stations were erroneously included at a space requirement of 6,000 m^2 (as part of the Underlying substations). This explains why the figures in II3050-2 are about 60% of those in the previous report.

2023 and 2050 12 km to 16 km of cable will have to be laid. The fact that this involves construction in urban areas, especially in the case of LV cables, illustrates how enormous this societal task is.

Table 23: *Underground space requirement for regional network operators across all of the Netherlands.*

Voltage level	Regional	National	European	International
MV cables	274 km^2	274 km^2	257 km^2	219 km^2
LV cables	54 km^2	54 km^2	47 km^2	40 km^2
Total	328 km^2	328 km^2	304 km^2	259 km^2

11.3.6 Rough picture of the space required for heat and CO_2 infrastructure.

The possible development of CO_2 infrastructure is described in Chapter 9. Much is still unclear and the developments depend on the scenario that unfolds. However, it is clear that existing pipeline corridors must be chosen for the routes as far as possible, especially the reserved corridors that are defined within the scope of the Structure Vision for Pipelines. This choice is also noted in the *Programma Energiehoofdinfrastructuur*. Based on that philosophy, the spatial impact of constructing a CO_2 transmission network in the Netherlands is likely to be minor.

However, the situation is different for heat grids. Although a heat grid is not a national entity, but limited to a region, an entire network does need to be built in that region. In most cases, urban areas will be connected to one or more heat sources in a nearby industrial area. So connections must be constructed for this, between the heat source and the city. Like the electricity grids, this means that excavation work will need to be done in many city streets. This study did not investigate the number of households involved in each area. That would require more accurate information about the development of heat grids in the different regions; the scenarios do not specify this regionalisation.

11.3.7 Rough picture of the space required for sustainable generation

Methodology and assumptions

The regionalisation of the installed capacities for solar and wind power is described in Chapter 2. *Regionalisation of the scenarios*. To estimate the space requirements for solar farms and wind power, the Generation Energy report[49] and also the Draft MESP - Appendix X[50] were referenced. The key figures for the number of MW per km^2 vary depending on the source and, as you would expect, with the passage of time. The figures in the right-hand column of the table below have been used in this report. Because the space requirements presented here are indicative, the *cumulative average* key figures will continue to evolve over time and depend, for example, on the cluster size used for wind - six turbines in the Draft MESP - and the degree of overplanting in solar farms (reduction of peak power feed-in). This must be taken into account when making comparisons with other calculations of the present and future space requirement.

Table 24: *Key figures for the indicative space requirement for solar farms and wind power. The minimum and maximum values have been taken from [49]).*

Category	Unit	Min.	Max.	II3050-1	PEH	II3050-2
Onshore wind	MW/km^2	4	8	6	12	8

49 *Generation Energy & PosadMaxwan, 2020*

50 *Pondera and CE Delft, APPENDIX X Beoordelingsmethodiek Milieu & Ruimte 2023 [2023 Environment & Space Assessment Methodology]*

Offshore wind	MW/km^2	6	10	*not used*	-	10
Solar farms	MW/km^2	48	156	102	150	100

Results

In relation to the four scenarios, these key figures were used to determine the *total* indicative space requirements for solar farms and wind power capacities in the 2050 final picture. See Section 11.3.2 for the different impact or nature of the space claim for solar and wind energy, in comparison, for example, to the claim imposed by infrastructure and flexibility resources.

Table 25: *Indicative space requirement for onshore wind power (15, 20, 10 and 10 GW), offshore wind power (45, 72, 38 and 46 GW) and solar farms (58, 58, 35 and 35 GW)*

Category	Regional	National	European	International
Onshore wind	1,875 km^2	2,500 km^2	1,250 km^2	1,250 km^2
Offshore wind	4,500 km^2	7,200 km^2	3,800 km^2	4,600 km^2
Solar farms	580 km^2	580 km^2	350 km^2	350 km^2

The space requirements for solar farms and wind power are also broken down by province, according to the regionalisation described in the II3050 scenario report [51], and presented in illustrations for each of the scenarios in the Appendix.

11.3.8 Rough picture of the space required for flexibility resources

Methodology and assumptions

To estimate the additional space requirements for flexibility, the key figures for the specific space utilisation associated with the number of MW or TWh per km^2 were taken from the sources below.

***Table 26:** Key figures for the specific space requirement per flexibility resource.*

Category	Unit	Value	Source
Power-to-gas	MW/km^2	3,000	Generation Energy
System batteries	TWh/km^2	0.014	Generation Energy, Draft MESP
Gas-fired power stations	MW/km^2	21,300	EnergieNL, Draft MESP
Hydrogen storage (space above ground)	TWh/km^2	8	Gasunie

In respect of the four scenarios, the space requirements for the flexibility resources were determined for all of the Netherlands (Table 27) based on the key figures. These space requirements are limited compared to those for solar and wind, but have an impact of a different nature. Compared to the space requirements for infrastructure, the claim for system batteries is large; it ranges between about 4,500 and 6,500 football fields. Power-to-gas (electrolysers) needs about a quarter of the space required by system batteries, but this is still more than that required for the substations. Note that the scenarios with more solar and wind power also require more space for flexibility resources.

[51] The Energy System of the Future: the II3050 Scenarios (NBNL, June 2023)

Table 27: *Indicative space requirements for flexibility resources.*

	Regional	National	European	International
Power-to-gas	8 km^2	8 km^2	5 km^2	3 km^2
System batteries	33 km^2	32 km^2	23 km^2	23 km^2
Gas-fired power stations	0.9 km^2	0.7 km^2	0.5 km^2	0.7 km^2

The space claim for the gas power stations is smaller than the space for the currently existing natural gas power stations. That means reuse of the associated zoning does not involve a *new* space claim. The Draft MESP[52] stresses this benefit. New space *is* required for power-to-gas and system batteries. In the relevant scenarios, the nuclear power plants are located at Borssele and in the Maasvlakte industrial park. No data is presented for power-to-heat as a flexibility resource. The installations in question are not separate installations - such as electrolysers and system batteries - but largely already present in the energy system as normal, peak or back-up resources in the heat infrastructure (see Section 11.3.6.).

Hydrogen is stored in Groningen and Epe (Germany) where the field also extends partially into the Netherlands (Overijssel). The space requirement above ground is very limited, given the amount of energy stored.

Table 28: *Indicative space requirements for hydrogen storage above ground.*

Province	Regional	National	European	International
Groningen	2.2 km^2	1.4 km^2	1.5 km^2	3.0 km^2
Overijssel	0.4 km^2	0.3 km^2	0.3 km^2	0.6 km^2
Total Netherlands	2.6 km^2	1.7 km^2	1.8 km^2	3.6 km^2

The space requirements for flexibility resources, following the regionalisation described in the II3050 scenario report [51], are also broken down by province. The associated figures are included in the appendix.

11.4 Energy system feasibility

Introduction

The feasibility of realising the energy infrastructure is a major concern. An awful lot needs to be done to achieve the climate-neutral goals. II3050-2 further underscores this. In addition to the costs and spatial impact, feasibility is also a key aspect of achieving the climate-neutral goals. Feasibility in this context means the technical and practical feasibility, i.e. manpower and the completion times.

Scope

This report is limited to the specific infrastructure-related activities within the scope of the network operators: i.e. the electricity grids and the gas grids operated by the regional and national network operators. In the case of gas, this involves the methane and hydrogen networks and hydrogen storage. Because of the scale and storyline of the scenarios, the feasibility of the hydrogen networks is included in the scope of the II3050-2 outlook.
The feasibility of the activities for constructing the heat grids and CO_2 networks falls outside the scope of this chapter. This is because the professional expertise of the parties that commissioned this study does not currently extend to these activities. However, during implementation, the total infrastructure task must be considered

52) Chapter 8: 'For these reasons, central government considers it very important that these sites be permanently available for installations producing large-scale, sustainable and dispatchable power. These are power stations that in the future will be hydrogen-based or green gas-based, for example, or feature a combination with CO_2 capture. It is expected that these locations will provide sufficient space.'

because the civil engineering works and the availability of the physical locations (including route corridors) depend on the overall activities.

A testing challenge

Given the insights and knowledge provided by the second edition of II3050 regarding the future energy system, the obvious question is whether these scenarios can actually be realised in the period up to 2050. Where do the bottlenecks arise? And what is needed to resolve them? To give a rough idea of this, this section describes the scope of the work needed in relation to the electricity grid, gas network, hydrogen network, CO_2 network and the heat grid.

Relevant in this context: the next section describes the raw materials needed for the Dutch energy transition in the different scenarios of II3050-2, and then the required scaling up of production capacities for the various energy technologies.
In the context of the network operators' investment plans, more information about the feasibility of those investment plans in the period to 2035 will become available later in 2023.

Electricity

This section describes the new construction required for the electricity system - stations and cables. The first step was to review what was actually completed in the period from 2019 to 2022. This review revealed that the network operators are scaling up. As a result, the averages over this period are not fully representative of the current production figures. The definitions of 'production' or 'volume of workload' in the 2019-2022 review and in the analyses in this outlook are not quite the same.

Three periods are distinguished in the network calculations: first 2023-2030, then 2030-2035 and finally 2035-2050. The mean is then calculated of the numbers over each of these periods. These numbers relate to the entire country. It is unlikely that things will turn out like this in all cases; further studies are still being conducted to arrive at optimal choices, and detailed grid designs continue to be made. The stated numbers are the result of an analysis of key figures and building blocks. Nevertheless, the overall picture they paint is accurate: it is clear that the network operators face a huge task.

In the case of the LV cables (see Figure 79), the size of the work package for 2023-2030 is 200% to 300% higher than the average production of the past five years. In subsequent years, the work package in this area decreases. The clear issue here is whether this pace can be achieved. Potential bottlenecks include the capacity of the network operators themselves and the licences needed for work in the public subsurface domain. If this 2023-2030 work package is not fully completed, the remaining work must be added to the task for the subsequent years. That in turn may jeopardise the goals established in the interim period.

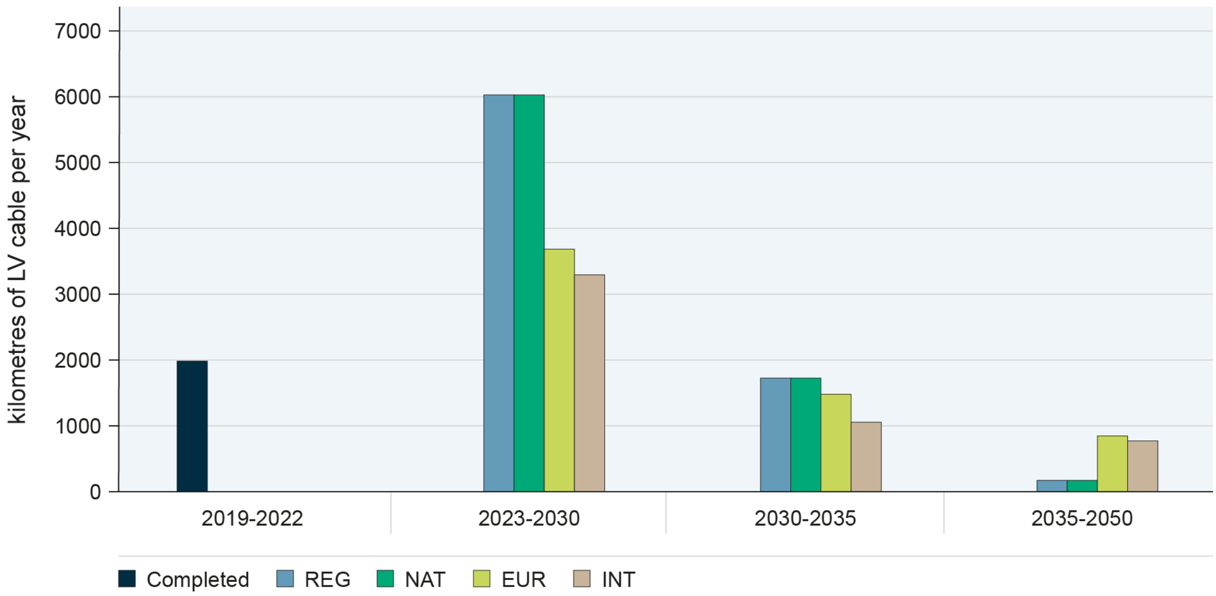

Figure 79: *LV cables task.*

The Decentral Initiatives and National Leadership scenarios also call for a significant increase in respect of MV/LV or distribution stations (see Figure 80). These are the more electricity-oriented scenarios. Again, a scaling-up of 200% to 300% applies in comparison to recent installations. As you would expect, this also follows the pattern of the LV cables.

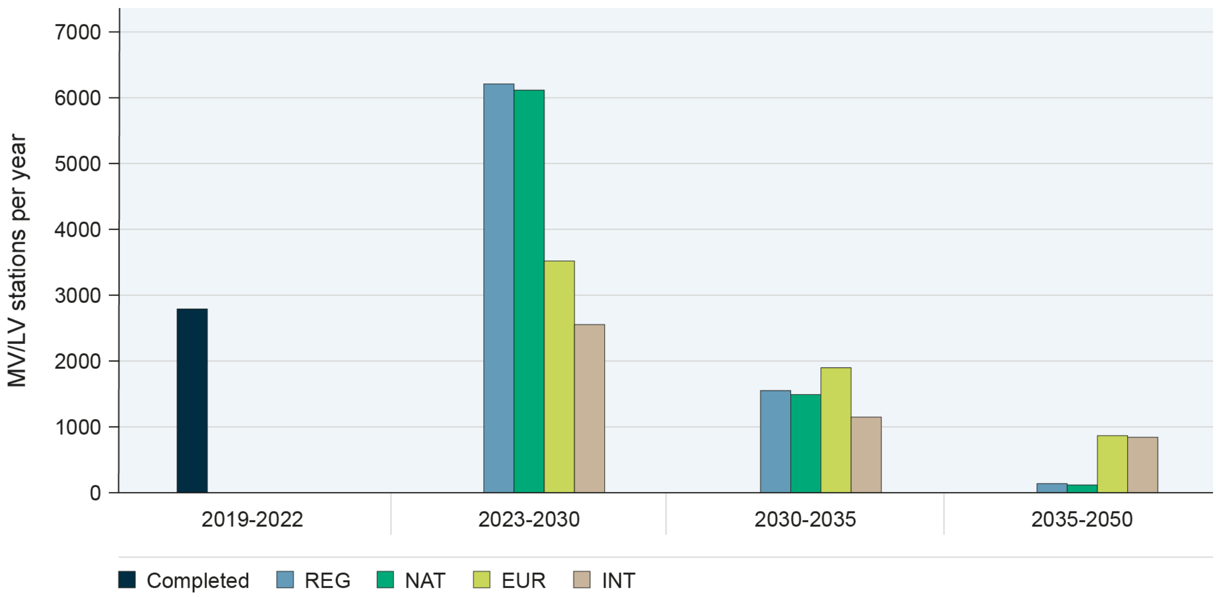

Figure 80: *MV/LV stations task.*

The picture for MV cables is slightly different; see Figure 81. Here too a substantial increase is called for in several scenarios, but the task in the period from 2030 to 2035 is also considerable and roughly 2 times higher than the recent production level. In the Decentral Initiatives and National Leadership scenarios, the work package for MV cables (for capacity!) is complete after 2035.

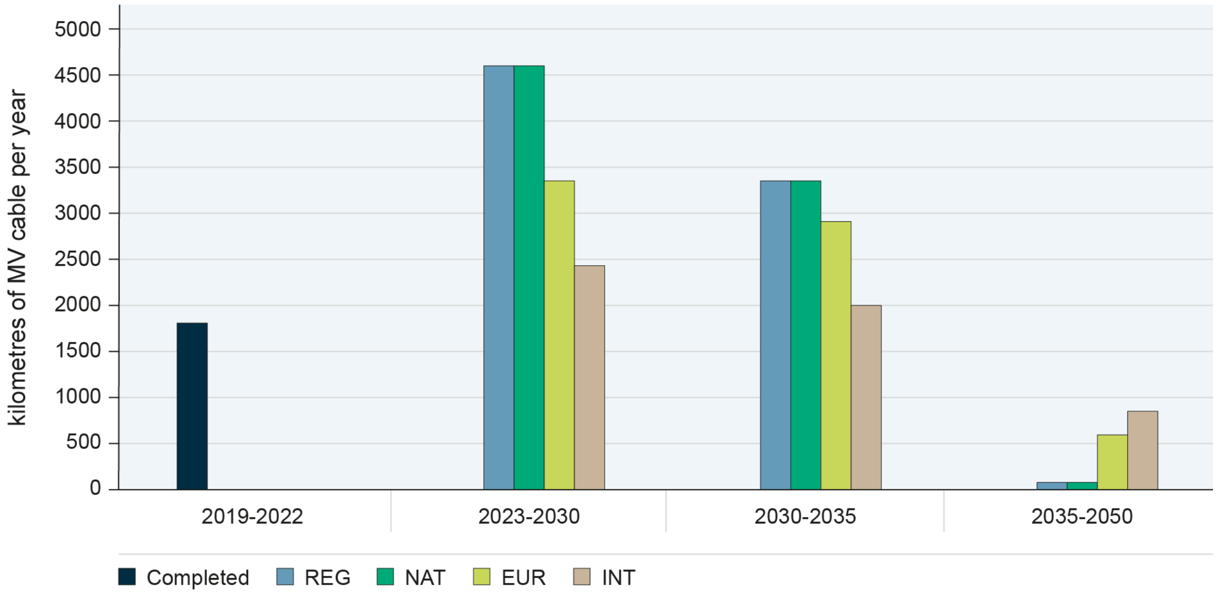

Figure 81: *MV cables task.*

In respect of the MV building blocks, this involves not only new 10kV to 25kV stations, but in many cases also expansion of existing stations. This also reduces the spatial task somewhat. At the same time, the desire to limit the impact in the event of an outage imposes a limit on the size of a station. But the amount of cabling that can physically enter and leave a station is also a limiting factor. This requires bespoke design on the part of the grid designers.

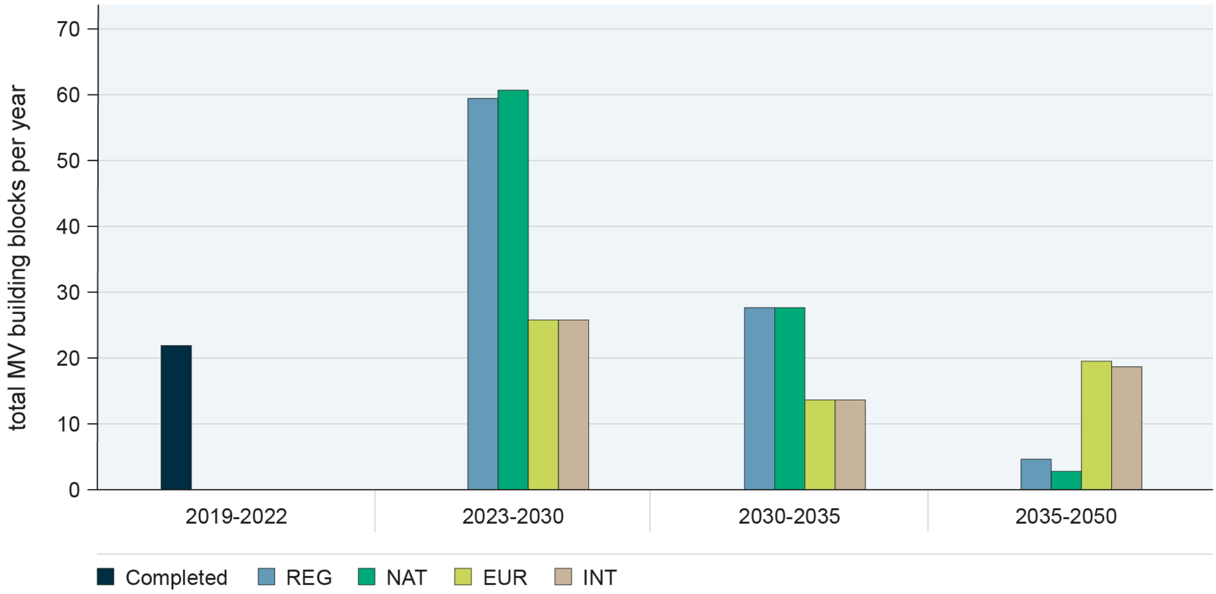

Figure 82: *MV building blocks task.*

Developing the number of interconnection points between the regional and national networks is a major task. Depending on the scenarios, new stations are expected to be built at a rate of 1 to 5 stations per year. These are the 150/50kV, 150/20kV or 150/10kV stations. This is a considerable task, but not an impossible work package. Split across the three major regional network operators, this task is feasible. Finding space is a further challenge, especially in the urban environment. Table 29 shows the task scope associated with building new substations. The best-case and worst-case situations relate to the ability to expand existing regional network stations. In a best-case situation, there are still good opportunities for this, and the number of new stations and the associated demand for space is not all that large. In a worst-case situation, these opportunities are not so good and many new stations must be built.

Table 29: *Substations task, in numbers.*

New stations	Best case	Worst case	Average per year
DEC	68	125	3-5
NAT	66	118	3-4
EUR	40	96	1-4
INT	24	67	1-2

In respect of the activities of the national transmission system operator TenneT, the scope of the work to be carried out between 2035 and 2050 cannot yet be reliably estimated. Given the long completion time for the construction of above-ground connections and stations in particular, time can be saved through proper coordination, including prioritisation, and making a timely start on both preparation and projects for having the required grid upgrades in place on time. This applies especially to the National Leadership scenario, where both the offshore and onshore tasks are considerable.

The analysis shows that the network operators are already making good progress. According to the figures, this is still insufficient for the 2023-2030 period, but the network operators are scaling up. The extent to which this will be successful remains to be seen. At all events, this analysis indicates the impact on feasibility. In order to meet the intermediate goals for 2030 and 2035, the rate of work must be ramped up, especially in the Decentral Initiatives and National Leadership scenarios. The degree to which feasibility truly becomes a bottleneck depends on a number of factors. The key factors are those that network operators themselves can influence, such as innovation, working efficiently, recruiting technical staff and predicting customer demand in a timely manner. Obviously, the network operators are making every effort to increase the pace of implementation to the greatest possible extent.

Gas

The scope of the work for Gasunie, the national transmission system operator, is described in Chapter 6. As indicated there, the national hydrogen network, as envisioned in the period up to 2030, is not yet the final situation, and construction continues in all scenarios until 2050. Between 2035 and 2050, methane pipelines in the RTP may also be converted to hydrogen pipelines. This involves a rough maximum of 2,000 km of the RTP grid in the European Integration scenario and 3,000 km in the International Trade scenario. However, much of the work needs to be done in the next few years, in the period to 2030/2035. The investment plans of Gasunie Transport Services and HyNetwork Services provide further detail on this.

In terms of feasibility, storing hydrogen is a challenge in itself, partly because of the long completion time. One crucial aspect is the need to leach out a salt cavern, as a system must be set up to drain the brine. This requires specialised knowledge, it is an activity with a spatial impact and, if possible, a useful application needs to be found for the brine. Brine disposal is potentially a factor that limits the number of caverns that can be created for hydrogen storage.

Chapter 8 describes the measures that are required for the regional gas networks. This involves a combination of placing boosters to feed local overproduction of green gas into the national network and removing gas networks in areas where a heat grid or an all-electric district is envisioned. In the scenarios, the latter scope varies from 34,000 km to 83,000 km of pipeline that need to be removed. The measures also include the work needed to convert existing networks to hydrogen networks.

No comparison can be made based on the current pace of work in this respect, as this conversion work mainly involves new activities.

The same applies to CO_2 and heat: these are mainly new activities and it is difficult to estimate, based on current knowledge, whether the required work is feasible within the specified period.

Task evaluation
The conversion of the energy system cannot be compared with the traditional activities of the network companies. This makes it difficult to quantitatively substantiate the feasibility of the scenarios.

In the case of electricity, scaling up in the relatively short term is a considerable task. Because of those 2030-2035 objectives, extensive additional construction is needed in the short term. The work pressure is greatest in the low voltage domain. In the medium voltage domain, the work is spread over a longer period, but the task there is also considerable. In the two electricity scenarios, Decentral Initiatives and National Leadership, the task is greater than in the other two scenarios. The extent to which realisation is feasible will be identified in the 2024 investment plans. The first edition of II3050 showed stronger task growth. The fact that the task seems smaller now partly reflects the major acceleration in implementation that has already begun.

For gas, the conversion operation is extensive. In the context of the regional gas networks, it is important to identify which areas may be supplied with hydrogen.

11.5 Scarcity of raw materials and products

11.5.1 Introduction

In recent years, increasing attention has been given to the enormous need for raw materials that arises when transforming the current energy system into a sustainable energy system. Scarcity and shortages may arise as a result. This jeopardises the feasibility of the energy transition, which may prevent climate targets from being met. This section introduces the topic of resource scarcity and also addresses scarcity of semi-finished and finished products, which has a more direct impact on network companies and developers. Some of the differences between the four II3050 scenarios are then discussed in the light of this raw material and product availability issue. Finally, the prospects for action and management are analysed.

Raw material requirements for sustainable energy (technologies)
The topic of raw materials in relation to the energy transition is attracting increasing attention, due in part to a number of reports that have been published, in particular *The Role of Critical Minerals in Clean Energy*

Transitions[53], *Critical materials for the Energy Transition*[54], *Een circulaire energietransitie [A Circular Energy Transition]*[55] and *Energy Technology Perspectives 2023*[56]. Additionally, the raw materials issue in a broader sense has become a topic of focus in politics, within the EU in the form of the *Critical Raw Materials Act*[57] and through adoption of a raw materials strategy in the Netherlands[58]. Attention is also given to this topic in the *Draft NESP*[59].

The transition to a climate-neutral energy system means a change in the need for raw materials, both in terms of the quantities needed and in terms of the types of raw materials. The energy supply is no longer based on huge amounts of fossil hydrocarbons and combustion machinery, but rather large amounts of new types of metals for the purpose of sustainable generation, storage, conversion, other flexibility resources and so on. The demand for metals such as copper, aluminium and iron will rise sharply. However, the demand for lithium, cobalt, nickel and the rare earth elements will sky-rocket. The latter include neodymium, dysprosium and praseodymium. This presents a challenge, both in the Netherlands and globally: all countries are transitioning to a climate-neutral energy system at varying speeds. In all these countries, the need for these metals is rising to such an extent that the question inevitably arises: how soon and where will bottlenecks occur? And what impact will those bottlenecks have on the energy transition in general, and in the Netherlands in particular? What does the impact look like, per scenario, in the final picture of the energy system?

Table 291 below, a combination and adaptation of Figure 5.5. from Witteveen+Bos[60] and Figure 15 in Metabolic's study [55], shows a selection of the metals used for the different technologies and where there is a certain supply risk. Of course, other metals are relevant too, but they are not associated with a supply risk; e.g. iron for pipes, wind turbine towers and high-voltage pylons, among other products. The full table and the method used to arrive at a final assessment of the supply risks can be found here [60].

Table 291: *Minerals associated with a certain supply risk in relation to technology, compiled based on a combination of two publications [55, 60].*

Technology	Copper	Aluminium	Nickel	Cobalt	Lithium	Dysprosium	Terbium	Yttrium	Lanthanum	Praseodymium	Neodymium	Indium	Molybdenum	Silicon metal	Natural graphite
Solar PV	•	•										•	•	•	
Wind	•	•	•			•	•			•	•		•		
System batteries	•	•	•	•	•										•
Electric vehicles	•	•	•	•	•	•				•	•				
Electrolysers	•	•	•	•				•	•						
Electricity infrastructure	•	•													

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53 The Role of Critical Minerals in Clean Energy Transitions (IEA, 2021)
54 Critical Materials for the Energy Transition, (IRENA, 2021)
55 Een circulaire energietransitie [A circular energy transition] (Metabolic et al., 2021)
56 Energy Technology Perspectives 2023 (IEA, 2023)
57 Study on the EU's list of Critical Raw Materials (EU, 2020)
58 Evenwichtig sturen op de grondstoffentransitie en de energietransitie voor brede welvaart [Balanced management of the raw materials transition and energy transition to preserve broad prosperity] (SER, 2022)
59 Draft NESP, working document D (Dutch Ministry of Economic Affairs and Climate Policy, 2023)
60 Scenariostudie kernenergie [Nuclear power scenario study] (Witteveen+Bos et al., 2022)

Scarcity in the value chain for sustainable energy (technologies)

In addition to resource scarcity, scarcity of materials, equipment and production capabilities plays a role, each with its own dynamic. The value chain in the figure below has been included to aid understanding here.

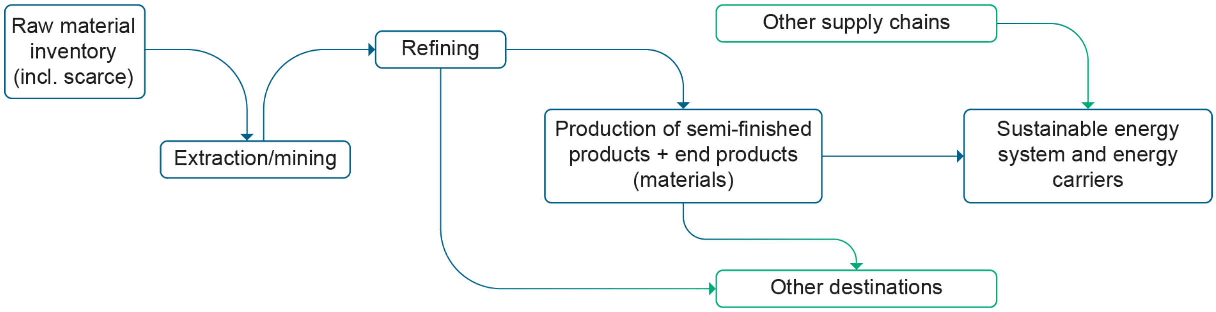

Figure 83: *A diagram of the value chain for sustainable energy (technologies).*

The value chain consists of a number of sequential steps. They concern the availability of the raw material, the total reserves, technically extractable and economically extractable reserves, the extraction capacity, the refining capacity, transport and, finally, the manufacture of semi-finished and finished products, i.e. materials. In addition, (scarce) resources are also used elsewhere. ‘Other uses’ such as microchips and medical and defence equipment, for example, require the same raw materials and/or semi-finished products as the sustainable energy system.

Furthermore, it makes sense to separately consider supply chains that may not be dependent on scarce raw materials, but which may constrain the development of the sustainable energy system in some way. In relation to these ‘other supply chains’, the IEA report *Energy Technology Perspectives* - based on projections through to 2030 - identifies two examples that are illustrative of the pressures they exert on energy transition ambitions:

- There are currently about 10 ships operating outside China worldwide that are active in offshore wind farm construction. In 2030, 50 of these ships will be needed worldwide, but only 15 are being built and/or are currently planned in the period up to 2026. This rate of construction must be maintained to 2030 at least.

- When it comes to ammoniac and hydrogen tankers for global transport, IEA projections call for respectively 170 and 20 to be built and operational by 2030. These numbers too are far from trivial, given the limited construction capacity in the maritime sector.

Two types of challenge can be identified in the chain from scarce raw material to semi-finished and finished products and finally to a sustainable energy system.

- The first type concerns dependencies and vulnerabilities in or caused by the value chain, vulnerabilities that are already manifesting themselves now. An example is the concentration of the deposits of some metals and suitable refining capacities and production capacities in a very limited number of countries. For example, platinum is concentrated in South Africa (more than 70%) and cobalt in the Democratic Republic of Congo (more than 70%). China has more than 70% of the rare earth element reserves and refining capacity, almost 80% of the production capacity for solar and battery systems, more than 50% for wind systems and 40% for electrolysers. Geopolitical developments, but also, for example, natural disasters combined with the dependence on a limited number of countries, and long overseas transport distances can lead to serious disruptions in the supply of sufficient raw materials and products.

- The second and currently most pressing challenge is the required scale-up of the production capacities at all the individual steps in the value chain. That is needed to meet the substantially higher level of demand at the end of the chain due to the energy transition. Scaling up leads to a huge increase in absolute quantities of raw materials and (semi-finished and finished) products flowing through the value chains.

The challenges of scaling up the sustainable energy (technology) value chain are the focus of the *IEA's* studies. As an example, by 2030, lithium production must increase by a factor of 7 and copper production by a factor of 1.5. In some IEA projections, the annual demand for copper, lithium and cobalt exceeds the annual production volume in 2025. In absolute terms, while there may be sufficient ore reserves worldwide, extraction and refining are not scaling up fast enough to keep up with demand.

The same applies to the production capacities for semi-finished and finished products, such as electrolysers, power transformers, wind turbine towers and transformer stations. So the investments must increase sharply almost everywhere - and to a much higher level than can be achieved with the existing (and projected) investments. However, due to a difference in completion times, this will not automatically eliminate the pressures in the value chain. Developing new extraction sites can take up to 10 years or more, while creating a new production facility for batteries, for example, is possible within a few years. On the other hand, some semi-finished and finished products are so high tech and labour-intensive that new entrants are unlikely, and capacity expansions are actually not possible - this is true, for example, of power transformers.

An important insight is that the situation varies greatly from one metal to another. *One size fits all* does not apply. Theoretically, there are enough ores on earth to meet the metal needs. But the economically extractable deposits are inherently difficult to estimate and come from a large or small - but always different - group of countries, some of which are accessible, but others less so. The development in refining and production capacities is only partially known and is uncertain, and international demand development (within or outside the energy system) varies depending on the metal and technology. Factors related to societal, environmental, political and labour rights conditions in and associated with the extraction of the various raw materials in the various countries also have an effect. How these aspects are involved in the strategies to acquire the metals and energy system components needed also has an effect on access to and the effective amount of raw materials and products available.

In summary, to bring the energy transition up to the desired development speed to achieve the required final picture in 2050, four factors can be distinguished:
1. Timely availability of raw materials.
2. Timely availability of production capacity, for example, for the production of batteries or power transformers.
3. Timely availability of equipment, for example, tankers or the ships needed to build an offshore wind farm.
4. Minimum disruption to the value chain due to geopolitical or other developments.

To illustrate the issues: the deposits of iron and the extraction capacity for iron ore are not bottlenecks. Adequate production capacity for steel is the next step. Then there needs to be sufficient production capacity for such items as pipelines, wind turbine towers or high-grade sheet metal materials for power transformers. And finally, ships capable of installing the wind turbine towers at sea must be sufficiently available. All these steps are important to successfully completing the energy transition.

11.5.2 Implications of the four scenarios

This section describes the raw materials needed for the Dutch energy transition in the different scenarios of II3050-2. It then considers the scaling up of production capacities for the different energy technologies that will be needed.

Raw materials

At the request of the network operators, Metabolic has recalculated the raw material requirements in line with the scenarios in II3050-2[61]. It is based on the same points of departure as those stated in their earlier report [55]. One important addition is that the four scenarios are now analysed separately and the need for each specific metal per scenario is clearly indicated, as is the component in the energy system that drives that need.

Based on the calculation, we see that the ten most needed metals in the period 2040 to 2050 are the same for each scenario and that their ranking hardly varies. They are calculated as a percentage of the global production in 2020 as the reference year. Table 30 shows the top five, in which iridium moves up to position 2 in the National Leadership scenario. The complete table is included as Appendix G.

Table 30: *The top five supply-critical metals with their range of expected annual demand, in the period 2040 to 2050 as a percentage of world production in 2020.*

Metal	Range
Lithium	25 – 28%
Dysprosium	24 – 27%
Neodymium	17 – 26%
Iridium	15 – 28%
Praseodymium	13 – 14%

In addition, the allocation across the different components of the energy system was quantified for each scenario. Figure 84 shows this allocation for lithium, neodymium, dysprosium and iridium; similar figures for ten metals are included in the appendix. Figure 84 shows the variation between the scenarios and the growth in the requirement, as an average per decade. The growth in the requirement depends heavily on the shape of the growth curve for each technology towards the final value in 2050. If the process is speeded up, the metal demand shifts to an earlier point in time. The top five metals are particularly relevant to the development of battery systems, electrolysers and wind power, as modelled by Metabolic. However, every part of the energy system faces scarcity.

[61] *De metaalvraag voor de Nederlandse energietransitie: een gedeeltelijke actualisering op basis van de nieuwe II3050-scenario's* [*The demand for metals in the Dutch energy transition: a partial update based on the new II3050 scenarios]* (Metabolic, 2023)

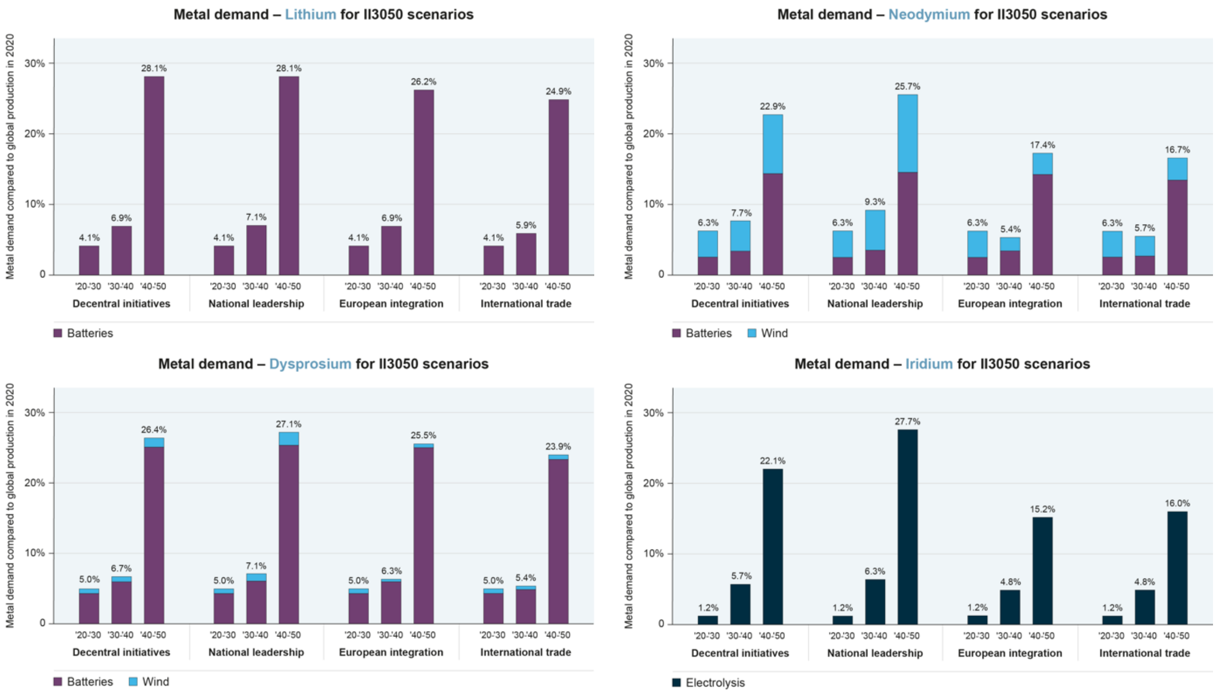

Figure 84: *The lithium, neodymium, dysprosium and iridium requirements (as a percentage of the respective global production in 2020) per scenario and broken down by decade, for the different components of the energy system.*

Three more aspects are important here:

- There is obviously a certain amount of uncertainty and therefore a range of possible outcomes. For example, for battery storage, it has been assumed (in deviation from Metabolic's earlier report) that the mix of battery technology in 2050 will be 70% LFP and 30% NMC[62]. Different assumptions lead to different results so the figures should be treated with caution.

- In the material flow model, the penetration of the technologies shows an S curve based on the values in 2019, 2030 and 2050. However, to know exactly what the II3050-2 scenarios require in terms of the metals, a growth line based on the II3050 development paths would provide more accurate information.

- The figures do not take into account the impact of the circular strategies of *rethink*, *reduce*, *reuse* and *recycle*. The earlier study shows that implementing these strategies can lead to a substantial decrease in metal demand. Depending on the raw material, the difference can be as much as 75% to 90% [55].

The above analysis and figures relate only to the *demand side* for the Dutch energy transition. No consideration is given to global demand from other sectors, such as defence or medical, or the demand driven by the energy transition in other countries. Nor has the supply situation between now and 2050 - per metal - been analysed. This makes it impossible to come to a firm conclusion based on these quantitative results[63]. The fact that the Netherlands, within the assumptions of the analysis, will need on average a quarter(!) of the 2020 world production of lithium annually in the period 2040 to 2050, and 4% in the period 2030 to 2040, does clearly illustrate the enormity of the challenge.

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62 LFP type batteries: lithium-ferrous-phosphor. NMC type batteries: nickel-manganese-cadmium oxide.

63 In line with the answer to Parliamentary questions on the strategic autonomy of the Netherlands in relation to the energy transition (July 2023): Answers to Parliamentary questions on the strategic autonomy of the Netherlands in the energy transition | Parliamentary Document | Rijksoverheid.nl

Scaling up production

To identify the future production capacities available for refining and the production of semi-finished and finished products, it is necessary to understand:

- All the different products;
- The current worldwide production capacities;
- How production capacity could decrease, through possible closure of capacity;
- How that capacity could increase in response to currently known and emerging investment plans - with the associated planned production;
- The investment plans relating to the more distant future through to 2050.

The IEA has analysed a number of cases based on a horizon up to 2030. An analysis of this type is beyond the scope of this II3050-2 document. However, there is an understanding of the production scale-up needed to achieve the final pictures of the Dutch scenarios. The table below shows what it would take between now and 2050 to achieve the final value of the most intensive scenario, i.e. National Leadership, assuming constant annual growth. The table shows the link between technologies, the increase in installed capacity in the recent past and the required increase in installed capacity. For the other scenarios, it suffices to apply the relevant percentage per technology to the acceleration factor.

Table 231: *The recent growth of different technologies versus a theoretical linear growth path, from 2023 to 2050, to assess the production scale-up that is needed.*

Technology	Realisation in 2021 and/or 2022 (GW/yr)	Demanded (NAT) - linear profile (GW/yr)	Required acceleration factor	Regional	National	European	International
Solar PV	3.8	6.2	X 1.6	106%	100%	73%	58%
Onshore wind	0.8	0.6	X 0.7	75%	100%	50%	50%
Offshore wind	0.5	2.8	X 5.6	63%	100%	53%	64%
System batteries	*zero*	1.4	X >100	122%	100%	63%	47%
Electric vehicles (numbers)	85,000	342,000	X 4.0	100%	100%	83%	67%
Electrolysers	*zero*	1.8	X >1,000	73%	100%	36%	40%

The table shows that the pace of production and installation must increase sharply to achieve the 2050 final picture in the National Leadership scenario. In the other scenarios, the ratio between required and realised capacities is generally lower. The exceptions are solar PV and system batteries in the Decentral Initiatives scenario.

This involves a factor of 1.6 for solar power and almost a factor of 6 for offshore wind power from 2023 to 2050. In the European Integration scenario, a factor of 3 applies to offshore wind power. For onshore wind power, the pace from 2022 to 2050 should at least be maintained in the National Leadership scenario. For batteries and electrolysers, the ratio is currently not meaningful because these technologies are still at a very early stage of development.

All of this is taking place in a global market of production and demand, where the energy transition is accelerating in many countries and the demand is rising sharply for the same technologies - largely to the same extent or even more strongly than in the Netherlands. Consequently, the Dutch figures are to some extent representative of global needs (see also [56]).

11.5.3 Action perspectives and management options

It follows from the above analysis that, in the light of the current global effort to build a climate-neutral energy system, there will be an immense need for certain metals. Production capacities must therefore scale up sharply. This is hardly surprising; replacing an energy system that has evolved over more than 100 years to its current size and complexity in a time span of just 30 years is no easy task. It seems almost inevitable that this will lead to scarcity at an early stage and even physical shortages in the coming years. That will slow the speed of the energy transition and cause a sharp increase in the associated costs. To a large extent, the Netherlands cannot solve the challenge entirely on its own - not even in the Decentral Initiatives scenario, which assumes many local initiatives. This is being worked on in a number of areas: at the European Union level, with the *Critical Raw Materials Act*, and in the Netherlands with the Raw Materials Strategy.

The National Raw Materials Strategy emphasises that the energy and raw materials value chains are closely intertwined and therefore must be addressed simultaneously. In other words, the energy transition is not possible without a raw materials transition, and vice versa. The draft NESP emphasises that, from the standpoint of global equity, disproportionate demands should preferably not be made on the globally available supply of raw materials. In the search for solutions, the National Circular Economy Programme identifies four approaches: *rethink*, *reduce*, *reuse* and *recycle*.

Reducing raw materials use - using fewer primary resources by not having products, sharing them or making products more efficient - is the *Rethink* circular strategy. The first and most important path to reducing raw material usage for the energy transition is also the most obvious: energy saving. Less energy demand leads to a lower-capacity energy system with a correspondingly large reduction in the raw materials and products needed for infrastructure, generation, conversion and storage. Some of this can be achieved with technology, but it also requires behavioural change.

Raw materials can be substituted - replacing primary raw materials with sustainable raw materials, such as high-grade sustainable bio-based raw materials, or more widely available raw materials with a lower environmental footprint. This is the *Reduce* circular strategy. Substitution, driven by technological innovation, is crucial at all steps in the value chain. Diversifying design and using technology that makes less use of scarce raw materials and/or products helps reduce the footprint.

The last two solutions focus on extending the useful life, *repair* (or *reuse* in some publications), and high-quality processing - *recycle*. The combination of the four strategies presented above can result in a drop in demand of 90% or more in the case of some metals.

The ‘landscape’ of the metals required differs between the scenarios in II3050-2. The top 10 remain unchanged but certain scenarios could mean a significantly lower requirement per metal. However, it is not easy to distil this into a robust development path for the energy system or define options for when certain metals become extremely scarce. Greater freedom of action can be created through the choice of technology. For example, the demand for scarce and rare earth metals could be reduced substantially if different types of wind turbine or batteries are used.

Other actions to reduce dependencies through greater European coordination focus on:

- Diversifying the countries of origin of raw materials, semi-finished and finished products as much as possible to reduce the dependence on a limited number of countries, thereby reducing vulnerabilities in the value chain;
- Developing the domestic and European potential for mines and mining and refining capacities in order to produce the metals required nationally or at the European level;
- Stockpiling reserves and entering into long-term supply contracts for critical metals.

Appendix A: Initialisms and definitions

Initialisms

ATR	Autothermal reforming
AVI	Waste incineration plant
bcm	Billion cubic metres – billion m^3
BECCS	Bioenergy with carbon capture and storage
CBS	Statistics Netherlands
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CES	Cluster Energy Strategy
COP	Coefficient of performance
CTM	Carbon Transition Model
DAC	Direct air capture
DEC	Decentral Initiatives scenario
DRT	Phase angle regulator
DSR	Demand side response
DRI	Directly reduced iron
EAF	Electric arc furnace
EHS	Extra-high voltage
ENTSOs	European Network of Transmission System Operators for gas (ENTSOG) and electricity (ENTSO-E)
ETM	Energy Transition Model
ETS	Emissions trading system
EUR	European integration scenario
EV	Electric vehicle
EZK	Dutch Ministry of Economic Affairs and Climate Policy
G14	14 largest industrial greenhouse gas emitters
GW	Gigawatt
HV, MV, LV	High voltage, medium voltage, low voltage
HTL	High-pressure gas grid
IA	International Ambition scenario
IEA	International Energy Agency
INT	International Trade scenario
IP	Investment plan of the network operators
KA	Dutch Climate Ambition scenario | *In 2022 IP*: Dutch Climate Agreement scenario
KEV	Climate & Energy Outlook (PBL Netherlands Environmental Assessment Agency et al, annual publication)
kV	Kilovolt, 1000 volts
LNG	Liquefied natural gas
NAL	Dutch National Charging Infrastructure Agenda
NAT	National leadership scenario
NEP	German grid development plan (*Netzentwicklungsplan*)
NGO	Non-governmental organisation

ND	National Driver scenario
NOVEX	*Nationale Omgevingsvisie Extra*, Dutch national strategy on areas in the physical domain designated for major transitions
NOVI	*Nationale Omgevingsvisie*, Dutch national strategy on spatial planning and the environment
NPE	National Energy System Plan
OCGT	Open cycle gas turbine
PBL	PBL Netherlands Environmental Assessment Agency
PEH	*Programma Energiehoofdinfrastructuur*
PIDI	Programme for Infrastructure for Sustainable Industry
RES	Regional Energy Strategy
SAF	Sustainable aviation fuel
SMR	Steam Methane Reforming
SMR	Small modular reactors
STEG	Combined cycle power plant, which includes combined cycle gas turbine (CCGT) plants and combined gas and steam (COGAS) plants
SVB	*Structuurvisie Buisleidingen*, Dutch national comprehensive strategy for pipelines
TVW	*Transitievisie Warmte*, Dutch transition strategy for heating
TYNDP	Ten Year Network Development Plan
VAWOZ	*Verkenning aanlanding wind op zee*, Exploration of offshore wind energy landing programme
WKK	Combined heat and power
WKO	Ground-coupled heat exchanger
TWh	Terawatt hour (= 3.6 petajoules, or PJ)

Definitions

Development	Change over time. In the context of network operators, a 'development' can be, for example, the adoption of new technologies in the energy system. There are certain and uncertain (potential) developments.
Trend	A movement or development that goes on over a prolonged period of time: a change in society, a change in the energy system, etc.
Certainty or uncertainty	A certain development or trend: there is a relatively firm belief, i.e. it is plausible, that the development or trend is ongoing and will continue. An uncertain development or trend: the development or trend may occur and/or continue, but there is no firm conviction (yet) that it will. The trend may still be bucked. The most fundamental uncertainties that also have the greatest impact on the networks have the greatest relevance in the scenarios.
Scenario framework	A framework for structured analysis of certain and uncertain developments for subsequent processing in scenarios that span these developments.
Broader environment scenario	Scenarios that are primarily intended to identify developments away from a network operator's immediate environment and to subsequently link strategic or operational and tactical scope for action to these developments.
Target scenario	Scenarios that chart various pathways towards a predefined goal. The II3050 scenarios are target scenarios. The 2024 IP scenarios can be characterised both as target scenarios and broader environment scenarios. They are target scenarios because the Dutch climate and energy transition policy is a firm underlying principle for those scenarios, and they are broader environment scenarios because they also provide a structured exploration of the uncertainties involved.
Policy ambition	A policy ambition is when a government has announced that it wants to implement a certain change. An ambition can be quantified by setting a target, such as the ambition to stay 'well below two degrees'.

Policy objective	An operationalised ambition where the government, instead of only drawing up policy instruments, also implements these instruments to ensure that the target is actually achieved. The '55% reduction by 2030' target is regarded as a policy objective via inclusion in the Dutch and European Climate Law.
Policy option	A possible policy instrument that a government can use to achieve its goals, generally to steer a societal development.
Policy choice	A choice made after weighing several policy options. Policy choices create clarity for society on the direction the government is taking.
Established policy	The whole set of policy instruments that have already been implemented in laws and regulations or that are about to be.
Proposed policy	Policy instruments in one of the stages of the policy-making process on which a decision has not yet been made and/or that have not yet been implemented in laws and regulations. They are not yet specific enough for the PBL Netherlands Environmental Assessment Agency to be able to assess the implications in the Climate & Energy Outlook (C&EO). It is not yet 100% sure that the policy will actually be implemented.
Policy on the agenda	Policy instruments in one of the stages of the policy-making process that have not yet been implemented in laws and regulations and the effect of which cannot yet be determined in specific and clear terms. The implications of this type of policy have not yet been assessed either, by using the national calculation system of the Climate & Energy Outlook (C&EO), for example.
Energy system choice	A specific choice to implement a number of changes to the energy system. This is often, yet not always, a policy choice because this kind of major change is almost impossible for an individual player to initiate. Examples include electrification of energy demand, developing a supply of renewables, and developing a heating network (heat grids for the built environment).
Electrification	Process where non-electric technologies are replaced with electric alternatives, such as electric cars and heat pumps to replace petrol and diesel-powered cars and standard gas boilers.
All-electric	Technology that uses only electricity, such as an all-electric heat pump, as opposed to a hybrid heat pump, which uses both electricity and natural gas to produce heat.
Energy hubs	An energy system concept made up of a large number of local solutions that balances energy supply and demand on a regional or a more specific level so as to reduce the need for transmission over longer distances.
Obligational approach	Policy where the government chooses the energy system and there is less freedom of choice. In the built environment, for example, choosing heat grids as the system to use in a certain district under an obligational approach would mean that operators are obligated to provide heat grids and not allowed to also supply renewable gases.
Individual approach	A policy with an individual approach allows individual companies and consumers extensive freedom to choose the energy solutions they prefer. In the built environment, this means, for example, that both electrification and gas solutions can be offered and that this is not controlled by a government body.
Target Grid	Dutch electricity TSO TenneT's vision for the power grid of 2045.
Dispatchable power plant	Power plants that can be switched on and off, or be ramped up and down to meet power demand as long as they have enough fuel.

Appendix B: Overview of numerical outcomes

Sustainable generation

Table 3: *Indicative space requirement (in km^2) for onshore wind (15, 20, 10 and 10 GW), offshore wind (45, 72, 38 and 46 GW) and solar farms (58, 58, 35 and 35 GW) in 2050. As presented in Section 11.3.7, Table 25.*

Category	Decentral Initiatives	National leadership	European integration	International trade	Unit
Onshore wind	1,875	2,500	1,250	1,250	km^2
Offshore wind	4,500	7,200	3,800	4,600	km^2
Solar farms	580	580	350	350	km^2

Flexibility resources

Table 2: *Overview of quantities and deployment of flexibility resources in the base scenarios. As presented in Section 3.3, Table 6.*

			2019	2030	2040				2050			
Category	Technology		Ref	KA	DEC	NAT	EUR	INT	DEC	NAT	EUR	INT
Electricity power stations	Nuclear	GW	0.5	0.5	0	1.5	4.0	0	0	3.0	8.0	0
		full load hour	7630	4860	0	6264	6172	0	0	6606	6597	0
	Coal	GW	4	0	0	0	0	0	0	0	0	0
		full load hour	4465	0	0	0	0	0	0	0	0	0
	Methane	GW	20	16	7	6	6	4	0	0	0	0
		full load hour	3662	1779	1134	1200	1072	1471	0	0	0	0
	Hydrogen	GW	0	0	11	9	9	11	20	15	11	15
		full load hour	0	0	1109	1056	1102	1205	874	978	835	922
Back-up heat grid	E-boilers	TWh	0	0	1	1	0	0	4	4	0	0
	Gas boilers	TWh	1	0	1	3	3	2	1	3	4	6
Supply response	Curtailment[64]	GW	0	31	43	49	41	34	47	40	36	48
		TWh	0	15	8	11	9	9	5	9	7	13
Flexible electricity demand	industry DSR	GW	0	2	5	5	3	3	8	10	4	3
		full load hour	0	84	559	558	627	707	301	451	605	627
	Power-to-gas	GW	0	3	15	17	9	8	25	25	16	10
		full load hour	0	5513	3964	4346	4117	3801	3909	4428	4126	3916
	Power-to-heat	GW	0	3	10	10	5	4	11	11	6	3

64 Unlike other flexibility tools, curtailment does not require a physical asset but involves an operational intervention in renewable generation. The figures shown here *exclude* ‘overplanting’ of solar PV (automatic capping of peak production).

		full load hour	0	1819	1145	1295	911	712	954	1550	1265	888
Storage	**Battery storage**	**GW**	0	9.3	42.4	42.0	29.2	24.7	70.3	59.7	38.6	40.6
		TWh storage volume	0	0.1	0.4	0.5	0.3	0.3	0.7	0.7	0.5	0.5
		Charge cycles	0	103	94	92	90	86	93	96	86	85
	Hydrogen storage	**TWh storage volume**	0	1	11	9	10	15	21	14	14	29
	Methane storage	**TWh storage volume**	0	36	13	14	20	15	6	5	12	1
	Heat storage	**TWh storage volume**	0	8	11	11	5	4	14	12	7	3
Import/export	**Electricity**	**GW**	7.8	12.8	14.8	14.8	14.8	14.8	18.8	18.8	28.8	28.8
		TWh net imports	3	-10	-13	-30	-23	-12	-7	-26	-28	-22
	Hydrogen	**GW**	0	10	15	15	15	15	20	20	25	25
		TWh net imports	0	-15	8	-31	27	69	-7	-8	1	95
	Methane	**GW**	106	105	100	100	100	100	95	95	90	90
		TWh net imports	99	182	46	45	53	48	-1	2	43	0

Table 3: *Indicative space requirements for flexibility resources in 2050. As presented in Section 11.3.8, Table 27.*

	Decentral Initiatives	National leadership	European integration	International trade	Unit
Power-to-gas	8	8	5	3	km^2
Large-scale (system) batteries	33	32	23	23	km^2
Gas-fired power stations	0.9	0.7	0.5	0.7	km^2

Table 4: *Minimum and maximum methane and hydrogen storage requirements in 2050, based on weather profiles from the past 30 years. As presented in Section 6.4.2, Figure 39.*

		Decentral Initiatives	National leadership	European integration	International trade	Unit
Methane	Max.	18	18	30	2	TWh
	Min.	3	2	7	0	TWh
Hydrogen	Max.	38	32	25	59	TWh
	Min.	11	8	7	17	TWh

Table 5: *Results for seasonal storage and flexible storage for methane and hydrogen in 2050. As presented in Section 6.4.2, Figure 40 and Figure 41.*

		Min.	Max.	Unit
Methane	Seasonal storage	0	29	TWh
	Flexible storage	0	4	TWh
Hydrogen	Seasonal storage	4	56	TWh
	Flexible storage	2	16	TWh

NB: This table shows the minimum and maximum values across the four base scenarios in 2050. The values for seasonal storage and flexible storage are not necessarily associated with the same scenario.

Table 6: *Indicative space requirements for hydrogen storage above ground (in km²) in 2050. As presented in Section 11.3.8, Table 28.*

Province	Regional	National leadership	European integration	International trade	Unit
Groningen	2.2	1.4	1.5	3.0	km^2
Overijssel	0.4	0.3	0.3	0.6	km^2
Total Netherlands	2.6	1.7	1.8	3.6	km^2

National electricity infrastructure

Table 7: *Indicative space requirements for new 220/380kV connections in 2050. As presented in Section 5.4.1.2.*

Additional route length required in km	Current situation	Decentral Initiatives	European integration	Unit
220/380kV grid	1500	320	510	km^2
220/380kV grid (% increase)	1500	20%	33%	%

Table 8: *Indicative space requirements for new 110/150kV connections in 2050. As presented in Section 11.3.3, Table 18.*

Additional route length required in km (area in km²)	Current situation	Decentral Initiatives	National leadership	European integration	International trade	Unit
110/150kV grid	4400	955 (33.4)	955 (33.4)	720 (25.2)	555 (19.4)	km (km^2)
110/150kV grid (% increase)	4400	22%	22%	16%	13%	%

Regional electricity infrastructure

Table 9: *Above-ground space requirement for regional network operators across all of the Netherlands in 2050. As presented in Section 11.3.5, Table 22.*

Voltage level	Decentral Initiatives	National leadership	European integration	International trade
110/150kV stations	1.8 – 3.7 km^2	1.8 – 3.5 km^2	1.0 – 2.4 km^2	0.6 – 1.6 km^2
Underlying substations	1.9 km^2	1.9 km^2	1.7 km^2	1.6 km^2
MV/LV stations	1.2 km^2	1.2 km^2	1.1 km^2	0.8 km^2
Total	4.9 – 6.8 km^2	4.9 – 6.6 km^2	3.8 – 5.2 km^2	3.0 – 4.0 km^2

Table 10: *Underground space requirement for regional network operators across all of the Netherlands in 2050. As presented in Section 11.3.5, Table 23.*

Voltage level	Decentral Initiatives	National leadership	European integration	International trade
MV cables	274 km^2	274 km^2	257 km^2	219 km^2
LV cables	54 km^2	54 km^2	47 km^2	40 km^2
Total	328 km^2	328 km^2	304 km^2	259 km^2

Table 11: *Numbers per asset type per scenario for 2050. The current number is included as a reference. As presented in Section 7.4.2, Table 10.*

	Current	Decentral Initiatives	National leadership	European integration	International trade	Unit
Stations (number)						
MV/LV stations	95,200	149100 (+57%)	148000 (+55%)	143000 (+50%)	132200 (+39%)	#
MV, MV/MV, IV/MV stations	1,870	2600 (+39%)	2580 (+38%)	2500 (+34%)	2480 (+33%)	#
Cables [km]						
MV cables	111,300	161100 (+45%)	161100 (+45%)	158100 (+42%)	151100 (+36%)	km
LV cables	186,900	241000 (+29%)	240700 (+29%)	233900 (+25%)	226900 (+21%)	km

National methane and hydrogen infrastructure

Table 12: *Indicative distance in km of the new H2 pipelines in the HPGG from 2035 (no extra space utilisation) in 2050. As presented in Section 11.3.4, Table 19.*

New H2 pipelines (*km*)	Situation in 2035	Decentral Initiatives	National leadership	European integration	International trade
HPGG H_2	approx. 1,100 km*)	150km	150km	80km	260km
HPGG CH_4	approx. 5,200 km	0	0	0	0

*) Onshore H2 network in 2035, largely based on converted gas infrastructure. Construction of the offshore network starts from 2030 and increases to about 400 km in the run-up to 2050 (no onshore space utilisation).

Table 13: *Indicative number of new hydrogen compressor locations from 2035 (space utilisation < 0.01 km^2) in 2050. As presented in Section 11.3.4, Table 20.*

New H_2 compressor locations *(number)*	Situation in 2035	Decentral Initiatives	National leadership	European integration	International trade	Unit
HTL	0	1	1	1	2	#

Table 14: *Indicative additional space utilisation for RTP pipelines transporting H2. For the EUR and INT scenarios, the space utilisation specified includes new connections for cluster 6 industry in 2050. As presented in Section 11.3.4, Table 21.*

Extra requirement *(km²)*	Current situation	Decentral Initiatives	National leadership	European integration	International trade
RTL	approx. 5,700 km	0	0	< 2,000 km (< 5 km^2)	< 3,000 km (< 7 km^2)

Regional methane and hydrogen infrastructure

Table 15: *Percentage of low-pressure network to be removed relative to percentage of households without a gas connection in 2050. As presented in Section 8.4.1, Figure 58.*

	Decentral Initiatives	National leadership	European Integration	International trade
Gas-free homes	75%	85%	45%	40%
LP main grid removal	66%	51%	30%	21%

Table 16: *boosters needed at a minimum booster capacity of 0 m^3/hour in 2050. As presented in Section 8.4.2, Figure 59.*

Booster threshold value	Decentral Initiatives	National leadership	European integration	International trade	Unit
0 m^3/hour	199	234	209	244	#

Other infrastructures (CO_2 and heat)

Table 17: *Distances between clusters and the Port of Rotterdam for CO_2 pipelines in 2050. As presented in Section 9.3, Table 14.*

Cluster	Distance [km]	Comments
Zeeland	140	to Rotterdam/Moerdijk cluster
North Sea Canal area	100	to Rotterdam/Moerdijk cluster
Chemelot	250	to Rotterdam/Moerdijk cluster
Northern Netherlands	220	to North Sea Canal area (from there on to Rotterdam)
	280	to Rotterdam/Moerdijk cluster

Table 18: *Requirement for heat transmission infrastructure in 2050, DN500 - DN1000 (pipe diameter approx. 50 to 100 cm). As presented in Section 9.6.2, Table 15.*

	Decentral Initiatives	National leadership	European integration	International trade
2040	approx. 300 km	approx. 350 km	approx. 250 km	approx. 150 km
2050	approx. 350 km	approx. 400 km	approx. 280 km	approx. 180 km

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Groningen/Drenthe Industry Cluster
Rotterdam-Rijnmond Industry Cluster
Zeeland Industry Cluster
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