Policy options offshore wind 2040

Final report

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Executive Summary

The European Union and its Member States have committed to climate neutrality by 2050. As an intermediate step, Member States have agreed to increase the greenhouse gas (GHG) reduction goal to a minimum 55% reduction by 2030. To meet the EU-wide GHG reduction target, the **Fit for 55 package** was published by the European Commission in 2021. While the proposals by the European Commission are yet to be negotiated and agreed upon by the Member States, they clearly show the level of ambition expected going forward. For example, the European Commission proposed to increase the renewable energy target to 40% by 2030 (up from 32% by 2030) and add a new sub-target for renewable fuels of non-biological origin (RFNBOs)[1] in industry[2]. According to the proposal, until 2030, 50% of hydrogen (H_2)[3] and derivatives used in industry must be renewable. While the target focuses on industry, the Member States are obliged to achieve the target. In its recent **coalition agreement**, the new Dutch government agreed to focus policy goals on reducing emissions further, with a goal of 55% reduction by 2030, and policies aimed at 60% in 2030.[4] After 2030, the aim is to achieve a 70% reduction by 2035 and 80% by 2040.

Meeting increased demand for electricity from renewable energy sources (RES) will be key to achieving GHG reduction targets, as electricity from RES is used to either supply current electricity demand, electrify demand currently supplied by other energy carriers such as natural gas, or produce green hydrogen and derivatives. The Roadmap Electrification envisages an additional electricity demand of 30 – 80 TWh by 2030.[5] The former State Secretary of the Ministry of Economic Affairs and Climate Policy estimated that if the Fit for 55 RFNBO targets would become binding, this may result in a green hydrogen demand of 14 – 31 TWh and that it would require 4 to 12 GW of electrolysis to supply this demand.[6] In the same letter to parliament, the State Secretary indicated this would require at least 6 GW of offshore wind to facilitate this hydrogen production, without detriment of decarbonisation of other electricity use.

In the Netherlands, **offshore wind has great potential to contribute to target achievement**, due to its scalability, speed of deployment, and large spatial and wind resources. Offshore wind is already an important pillar of the Dutch energy system. In the summer of 2021, 2.5 GW of offshore wind farms were operational and an additional ~2.2 GW was awarded through competitive tenders. The national target is expected to increase to realise a total capacity of circa 21 GW around the year 2030[7], a combination of the 2030 target of the *Klimaatakkoord* (11.5 GW) with the addition of 10 GW stemming from the *Extra Opgave Industrie*.[8] The former State Secretary of the Dutch Ministry of Economic Affairs and Climate has announced spatial procedures will start for offshore routes and landfalls of 12 GW, in addition to the current *Routekaart*. Targets for 2040 and 2050 are not yet

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[1] RFNBOs are essentially green hydrogen and its derivatives.

[2] Another RFNBO sub-target of 2.6% was proposed for final energy demand in transport. Also, a minimum target of 0.7% of synthetic kerosene in final energy demand in aviation (the total sustainable aviation fuels (SAF) target is 5%) was proposed.

[3] Please note that when we speak of hydrogen throughout the document, we always mean green/renewable hydrogen produced with electricity from renewable energy resources.

[4] Source: **https://www.government.nl/binaries/government/documents/publications/2022/01/10/2021-2025-coalition-agreement/2021-2025+Coalition+agreement.pdf**

[5] **https://www.topsectorenergie.nl/nieuws/routekaart-elektrificatie-laat-de-grote-potentie-van-elektriciteit-voor-de-industrie-zien**

[6] **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof**

[7] https://www.rijksoverheid.nl/documenten/kamerstukken/2022/02/11/kamerbrief-over-uitwerking-coalitieakkoord-klimaat-en-energie

[8] **https://zoek.officielebekendmakingen.nl/blg-979271**

established, however the *Programma Noordzee 2022 – 2027* aims to find sufficient sites to accommodate 38 GW.

Offshore wind faces two major challenges: integration in the North Sea and integration in the (international) energy system. This report deals with the second. **The main objective of the report is to obtain an overview of the possible policy options and instruments for a new approach to offshore wind energy**.

This report focuses on the timeframe up to 2040. For 2040, we expect a largely decarbonized energy system with high RES shares and high demand for green hydrogen. We recognize the need and ambition to already scale up domestic green H_2 production prior to 2030. Based on the developments that we are currently seeing we can formulate the following expectations for 2040.

For **electricity demand**, we expect:

- By 2030: Growing electricity demand driven by electrification efforts in sync with RES capacity additions and the ramp-up of domestic green hydrogen consumption, in line with the proposed 50% RFNBO target for industry. In addition, fossil electricity will be replaced by RES electricity, increasing the demand for RES electricity.

- By 2040: Large amounts of renewable electricity will be required to electrify demand sectors and produce green hydrogen.

For **green hydrogen demand**, we expect:

- By 2030: Significant ramp-up in demand driven by the proposed RFNBO targets; however, the green hydrogen market will not yet be liquid and there will only be a limited number of offtakers (these however may require large volumes). Demand will be partly supplied by imports and domestic production.

- By 2040: Liquid market with many offtakers and increased importance of imports and exports from/to neighbouring countries.

For **infrastructure**, we expect:

- By 2030: Most offshore infrastructure is electrical. The onshore electricity grid will continue to experience bottlenecks and long development lead times. Onshore hydrogen infrastructure (i.e. a backbone) will have been developed, but there is no large-scale offshore hydrogen infrastructure yet. First demonstrators of offshore hydrogen production are being realised.

- By 2040: The offshore electricity grid will become increasingly interconnected with a potentially meshed grid[9] emerging. For the onshore electricity grid, we expect continued reinforcements. For the offshore hydrogen grid, we expect wind farm-overarching hydrogen infrastructure. For the onshore hydrogen grid, we expect a further increase in the number of connected producers, customers and storage locations.

For **electrolyser capacities**, we expect:

- By 2030: An increase of the current national ambition of 3 to 4 GW by 2030 to meet the requirements outlined in the proposed RFNBO quota (parts of the quota may

[9] An interconnected grid rather than single, radial connections.

however also be supplied using imports). The deployment of these national capacities requires urgent policy decisions on which areas are available for hydrogen electrolysers, when to tender, which methodology to use and how to speed up the procedures if necessary.

- By 2040: We expect a large-scale build-out of electrolyser capacities onshore and potentially offshore.

To achieve both national and EU energy and climate targets, it is important to start preparing for the further roll-out of offshore wind. Policy makers and industry representatives alike want to ensure that the roll-out of offshore wind until 2040 is successful. To ensure such success, stakeholders need to **understand the challenges that the roll-out until 2040 may face**. Based on the expected developments partly detailed above and further explained in chapter 2, we identify three key challenges for offshore wind:

- Firstly, there is a **business case challenge**. Offshore wind farm investors may face increasingly volatile and uncertain electricity prices. The risk of uncertain revenues is influenced by several factors not necessarily in the span of control of developers/operators (low or negative power prices on the spot market, development of (renewable) electricity supply and demand, price of the emission allowances under the EU ETS, etc.). Some developments may result in decreasing prices (cannibalisation of wind energy and a large share of renewables in the mix), while others may result in increasing prices (e.g. increases of EU ETS prices, resulting in high prices at times when fossil based electricity is price setting). Overall, the uncertainty on the direction of developments provides a challenge for project developers.

- Secondly, there is an **infrastructure challenge**. Infrastructure is required to connect supply and demand. Risks could emerge with regard to the characteristics of future on- and offshore infrastructure, coordinating electricity and future H_2 infrastructure, financing infrastructure investments and cost recovery, timely availability of new assets (subject to long lead times), congestion issues and onshore grid reinforcement coordination, and uncertainty regarding location of new demand. Risks also arise out of coordinating interconnection and grid expansion schedules with neighbouring countries.

- Thirdly, there is an **integration and interface challenge**. Risks regarding the integration and governance of value chain interfaces emerge towards 2040 because integration increasingly happens across sectors. With direct and indirect electrification, the boundary of the electricity sector is expanded to include heating, mobility, and green hydrogen as an energy carrier. This results in interdependencies between these sectors, which in turn poses the risk that issues in one (e.g. realisation of electrolysis capacity or electrification of heat) impact the other (e.g. finding off-takers for renewable electricity).

The current Dutch approach to offshore wind roll-out has been successful by focusing on de-risking. As a rule, risks are allocated to those actors best able to cope and mitigate them. Offshore wind project developers generally have various mitigation options available to address risks and challenges that arise. Both infrastructure and demand-side actors appear more limited in their mitigation options. The government has the greatest set of mitigation options, e.g. through coordination of decision making and permitting, infrastructure realisation and support policies. We recommend **government intervention through policy and coordination to address these challenges**.

In the most recent years, the offshore wind roll-out in the Netherlands has progressed successfully without support payments to developers, as developers have been able to submit zero-subsidy bids. That is an extraordinary achievement made possible by numerous drivers of success. The focus for 2040 is to create or maintain the necessary framework conditions for a continued zero-subsidy roll-out. Based on our expectations of future challenges, we identify **the following current drivers of success that could remain relevant for a future roll-out**:

1. Pre-development by the state[10]: Like today, site characterisation will be required. This driver may be largely unaffected by future challenges. The goals of lowering barriers to entry, levelling the playing field, and minimising realisation timelines remain relevant.

2. One-stop-shop[11]: This concept remains valid, however what will be included in the one-stop-shop package may be dissimilar. Our considerations on the tender product are included in chapter 7.

3. Stable regulatory regime & predictable pipeline: While greater adaptivity may be needed to account for changes to offshore wind up to 2040 (see section below), regulatory stability and predictability should remain a priority.

As mentioned, while some of the current drivers of success should be continued, the policy framework must **adapt to the changes** that the 2040 offshore wind roll-out will be subject to. There will be a significant scale-up in offshore wind capacities by 2030 that will continue to 2040, necessitating an accommodating offshore wind approach (incl. governance, allocation mechanism, site definition and support policies). A greater interplay between offshore wind roll-out, onshore grid development, onshore demand development and system integration can be expected and should be incentivized by policy. From the offshore wind perspective, additional stakeholders, such as hydrogen producers, users, and industrial clusters, need to be considered in the allocation of sites. A fitting governance system is required for infrastructure, generation, and electrolysis developments.

Against the backdrop of these challenges, success factors and changes, Guidehouse was tasked by the Ministry of Economic Affairs and Climate Policy (*Ministerie van Economische Zaken en Klimaat, EZK*) and the Netherlands Enterprise Agency (*Rijksdienst voor Ondernemend Nederland, RVO*) to conduct this study. To complement this study, the Ministry has formed a working group with representatives throughout the offshore wind value chain. Regular monthly discussions with working group members served to collect views and insights from key stakeholders and engage with findings and recommendations. To meet the objectives of the study, Guidehouse used – in addition to the input from the working group meetings – literature research, bilateral interviews with working group members, expert

[10] In the current model, the pre-development phase starts with the designation of the search areas for future offshore wind farms, in accordance with the Water Act. Subsequently, a roadmap is established that stipulates which areas are to be realised by when and how they are connected to shore. Initial site boundaries are drawn and after that, site studies commence. RVO conducts investigations of the physical environment of the wind farm site, for both the soil, wind, and water conditions. This investigation provides extensive, high quality, data, such as geological, morphodynamical and geomorphological data, archaeological and unexploded ordnance analysis, metocean data, wind resource assessments, and geophysical and geotechnical data. This pre-development data is shared with interested developers to allow early access to pre-development information.

[11] The one-stop shop concept means that the successful bidder is awarded the exclusive rights to develop the wind farm in the concession, it is granted the key permits needed to realise the wind farm (the Ministry of EZK undertakes the necessary consenting activities), it is granted access to the grid via the offshore grid connection developed by TenneT (subject to entering into realisation and connection & transport agreements), and if a tender process with subsidy was followed, is awarded subsidy.

exchanges with EZK and RVO, insights from other countries (e.g. Denmark, the UK, Germany, Norway) and multi-disciplinary in-house Guidehouse expertise.

In the following paragraphs, we focus on part 2 of this study and present **policy options and recommendations** for the governance system, allocation mechanism, tender product and site definition and support policy instruments. All four of these policy fields are closely related and have many interlinkages. The governance system is the foundation of all other considerations as it determines which actor does what. Many of the roles defined here are then reflected in the allocation mechanism and tender product. The allocation mechanism and tender product are also closely related as how allocation is defined determines what gets allocated to bidders. There is also a connection between allocation and support policy instruments as if the subsidy-free roll-out fails, the allocation mechanism will have to not only allocate rights to construct, permits and access to infrastructure, but also support payments.

Figure 0-1 Structure of the report

For each of the four policy fields of part 2, we provide a short summary of key considerations and options or recommendations below.

Chapter 5: Governance

The above review of the challenges for the future offshore wind roll-out clarified the need for coordination by the government. This chapter addresses the strategic, overarching questions around the roles and responsibilities for the government and other actors in the future offshore wind roll-out. The chapter examines the governance model for offshore wind farms, offshore infrastructure, and electrolysers in detail. It then combines these elements into a masterplan that coordinates the site pre-development and definition with the infrastructure roll-out. In a last section, this chapter extends the masterplan considerations to the demand-side, specifically the industry.

Offshore wind farm governance

Currently a centralised governance model in the Netherlands is used to manage the development of offshore wind: the national government is responsible for most of the steps in the pre-development, development, and planning process of offshore wind projects[12].

Based on the identified key challenges for the further roll-out and success factors of the current approach, we consider pre-development by the state, the one-stop-shop approach and a stable regulatory regime and predictable pipeline as desired characteristics for further roll-out.

An alternative model is a developer-led governance model, which places more responsibilities with wind developers. This approach provides more flexibility for developers to optimise, however brings a few significant downsides, including limited ability to coordinate between different initiatives, longer lead times, sunk cost of unsuccessful development initiatives and higher development risk.

We consider strong direct governmental involvement important considering the pace required for the further roll-out, and the increasing need to coordinate between onshore and offshore infrastructure, between energy carriers and between various uses of the seabed. As a result, a centralised approach for the further roll-out is preferable and most elements of the current approach can be retained.

Offshore infrastructure governance

There are two main governance models used for the **offshore electricity infrastructure** between an offshore wind farm and connection to the onshore electricity grid. A developer-led model, where the wind developer is responsible to develop, construct and maintain the electricity infrastructure, and a transmission system operator (TSO)-led model where the onshore electricity TSO takes this responsibility.

We have considered the challenges for realisation of offshore electricity infrastructure, including the realisation of large capacities of offshore wind and the need to effectively integrate this onshore, the rapid roll-out pace required to meet targets, the move toward wind areas increasingly far from shore and the trend toward an increasingly interconnected offshore grid. Based on assessed pros and cons for the developer-led and TSO-led models, we **conclude that for electrical offshore infrastructure, a TSO-led governance model is preferable over a governance model led by private developers**.

The **combination of offshore wind and onshore electrolysis** may enable supply and (flexible) demand to grow in step. There are two main variants we distinguish: (1) on-grid electrolysis, where the onshore electrolyser has an onshore grid connection equal to its capacity, and (2) off-grid electrolysis, where there is no onshore grid connection but rather a direct line with the offshore wind farm. On-grid electrolysis has several advantages for the wind farm and electrolyser operators, including flexibility to consume produced electricity directly, the ability to provide minimum baseload electricity to electrolysers to avoid

[12] Rijksoverheid (2021), Rol van de Rijksoverheid bij wind op zee, **https://windopzee.nl/onderwerpen/participatie-educatie/rol-rijksoverheid/**

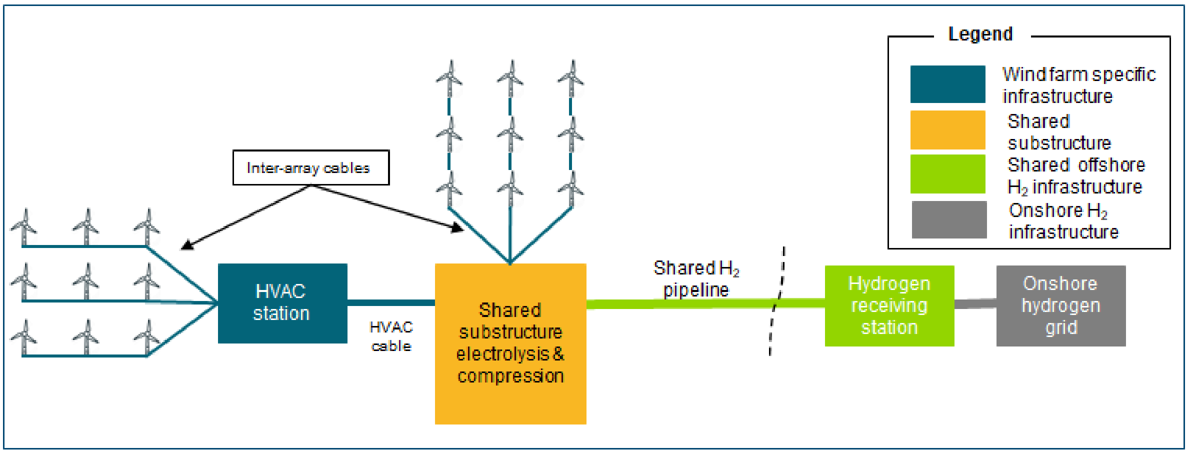
accelerated degradation, the ability to provide system benefits to the wider electricity grid, avoiding offtaker lock-in and the ability to contribute to the development of a competitive market for electricity and green hydrogen production. Off-grid electrolysis may be desired only in case transmission capacity limitations in the electricity grid do not allow for a grid connection.

With regard to on-grid electrolysis, we recommend assigning responsibility for offshore electricity infrastructure to the electricity TSO. For off-grid, in case of a direct line between an offshore wind farm and onshore electrolyser, it may be difficult to justify involvement of the TSO given that TSO involvement is not necessary to provide coordination between onshore and offshore grids, so responsibility is best assigned to the wind farm developer.

In practice, a hybrid between these two variants may be considered, where the onshore electrolyser has a partial (i.e. smaller than its installed capacity) onshore grid connection. This onshore grid connection may grow in capacity over time as the local grid transmission capacity increases. In such a case, coordination between the offshore and onshore electricity grids is again desirable, which may speak in favour of a TSO-led model. We recommend further investigating the implications of the proposal of the *Energiewet* as well as the forthcoming Delegated Act on sustainability criteria on the governance models that can be applied for off-grid and hybrid onshore electrolysis.

For **the combination offshore wind and offshore electrolysis** different considerations apply. As with electrical connections, we consider that coordination between onshore and offshore infrastructure, and infrastructure across wind farm sites (and possibly, search areas) is beneficial. Offshore hydrogen infrastructure greatly benefits from economies of scale, and it provides more flexibility in terms of transport capacity compared to electrical connections. In this summary, we focus on governance models for hydrogen infrastructure that connects multiple wind farms.

We have defined different groups of assets for which other governance considerations apply. The figure below shows an example for centralised offshore electrolysis.



For the ownership and operation of wind farm specific infrastructure we consider it appropriate that the wind farm developer is made responsible for realising the connection between the wind farm and the shared transmission infrastructure, i.e. the wind farm specific infrastructure. The reasoning for it is that we do not consider the wind farm specific infrastructure to be part of the offshore transmission grid (be it hydrogen or electricity), and as such it does not warrant making the offshore electricity TSO or hydrogen network operator responsible to realise these assets.

For the ownership and operation of shared offshore hydrogen infrastructure, we have considered three options: (1) wind farm developer, (2) onshore hydrogen network operator (HNO)[13], (3) a public-private partnership (PPP). Considering the benefits of realising a shared infrastructure, and the importance of such infrastructure in the future energy system, we argue that strong representation of public interests is desired, which speaks in favour of the onshore HNO or PPP. The main reasons against a developer-led model are the expected challenges to realise infrastructure at a scale beyond a single wind farm, possible barriers to providing non-discriminatory third-party access, and challenges to meet the expected unbundling requirements stemming from the recast of the Gas Directive. An onshore HNO-led model may offer better coordination between on- and offshore infrastructure and between the realisation of hydrogen and electricity infrastructure, while a PPP may offer better access to offshore gas industry experience and could facilitate re-using current infrastructure in case a PPP includes current pipeline owners.

Ownership and operation of a shared substructure or energy island have a different set of considerations that need to be taken into account. For assets that combine electricity and hydrogen transmission, involving both offshore electricity TSO and HNO may be appropriate. Involvement of the private sector through a PPP may be considered, which could stimulate innovation and reduce the need of public funds. The national government is envisaged to be the sole initiator of an artificial island. In case interconnection with other countries is realised, the impact on the business case of wind operators requires further consideration.

The second important question is how to realise third-party access to such shared infrastructure. The equivalent infrastructure in offshore gas (i.e. upstream gas pipeline network) shows multiple models used in Europe (e.g. in Norway it is regulated, in the Netherlands it is not) can be effective. The proposal by the European Commission for the recast of the Gas Directive and Regulation provides some guidance on the direction of hydrogen transmission regulation at EU level. In the proposal, hydrogen network operators are defined and tasked with realising and operating hydrogen transmission infrastructure, and their activities are to be separated from energy production. The proposal equates onshore and offshore hydrogen networks and does not make a distinction for upstream hydrogen networks (as is done for natural gas). Regarding regulation, the proposal states that Member States may implement negotiated third-party access or regulated third-party access up to the end of 2030 and requires Member States to implement regulated third-party access after 2030. The question when a hydrogen pipeline constitutes a network or when it is a direct line merits further legal assessment. However, in case of connecting multiple wind farms to shore it seems likely this would be deemed a hydrogen network. In this case, the proposal defines which regulation should be applied.

In our view, the degree of regulation should (1) promote a level playing field between offshore wind farm developers by providing tariff clarity at time of the wind tender (2) mitigate the risk of discriminatory access incentives and (3) mitigate the risk of abuse of market power as there will be limited to no competition between hydrogen infrastructure providers.

The second question is which parties should bear the responsibility of realising and operating offshore hydrogen infrastructure. In our view, the responsibility for the infrastructure between the wind farm and the shared offshore infrastructure (e.g. a pipeline or artificial island) is best placed with the wind farm developer.

[13] In the proposal for a revision of the Gas Directive and Regulation, the EC defines the hydrogen network operator as a party that is tasked with realising and operating hydrogen transmission infrastructure.

We recommend engaging with the actors in the on- and offshore natural gas industry to uncover lessons learnt in the Dutch natural gas industry and test these options for third-party access and ownership further.

Electrolyser governance

Electrolysis installations are envisaged to be realised and operated by private parties.[14] **Onshore electrolysis** installations may - depending on the allocation mechanism used - also be owned by a consortium which includes a wind farm developer. The key question for onshore electrolyser governance is the degree to which the government can play a role in the development stage. If spatial planning and permitting activities for onshore electrolysis are successfully undertaken by the government like for offshore wind, it could reduce the realisation time from tender until start of operations by 2 to 3 years.

Executing the environmental impact assessment requires defining a suitable bandwidth such as the footprint and dimensions of the electrolyser, within which a developer may realise the electrolyser. This may pose difficulties due to the novelty of large-scale electrolysis. We recommend engaging with electrolyser manufacturers, and electrolyser developers to understand whether the definition of a design bandwidth is possible and by when.

In case it is not possible in the short term to define an appropriate design bandwidth, the active governmental role can be focussed on streamlining the spatial planning processes (including facilitation of land rights) and permit processes, while the actual environmental impact assessment and permit application process would remain the responsibility of the developer.

For **offshore electrolysers**, we distinguish between integrated (i.e. in or next to the wind turbines themselves) and centralised electrolysis. For integrated electrolysis, the electrolysers are an integral part of a wind farm. Thus, the responsibility for realising and operating the electrolysers lies fully with the wind farm developer. For centralised electrolysis, there are three main options to consider:

1. Ownership & operation by **wind developer**: in this case, the wind developer is able to sell the produced hydrogen to an offtaker onshore. As an implication, the electrolyser capacity is linked to the capacity of a single wind farm.

2. Ownership & operation by a **third party that produces and trades hydrogen**: in this case, the wind developer sells its electricity to a third party that owns and operates the centralised electrolyser. The produced hydrogen is traded by the party. The electrolyser may have a larger capacity, overarching several wind farms.

3. Ownership & operation by a **third party that provides conversion as a service**: in this case, access to use the electrolyser is provided to the wind developer by the third party. While the third party owns and operates the electrolyser, it does not become owner of the produced hydrogen, as it provides conversion as a service. The wind developer owns and trades the produced hydrogen.

Some parties in the working group indicate that the economies of scale for large scale *onshore* electrolysis start levelling off once reaching the gigawatt scale, but whether this is the case for offshore electrolysis as well requires further investigation.

[14] In a letter to parliament the state secretary of the Ministry of Economic Affairs and Climate Policy recognised a possible role for network companies in case private parties do not develop electrolysis capacity sufficiently quick.

In case the electrolysers are operated by the wind developers, and a shared substructure or island is used to host electrolysers of multiple wind farms, it is necessary to provide clarity on the available space and infrastructure, and associated tariffs to use the substructure, prior to publishing the offshore wind tender.

Considering the maturity of offshore electrolysis, and the residual questions that require further investigation, it is not possible to conclude which governance model is best suited for centralised offshore electrolysis. Thus, we recommend keeping options open to further investigate different governance models going forward.

Masterplan

Towards 2040, the offshore wind roll-out becomes more complex due to uncertainty with regard to increasing considerations for electricity and hydrogen demand growth, the speed of development of electrolysis and hydrogen infrastructure and greater coordination requirements for onshore and offshore infrastructure. The decision which infrastructure is used to connect search areas must be based on an appraisal of electricity and hydrogen supply & demand developments, infrastructure requirements and realisation timelines. To ensure alignment between these different elements, coordination by the government is required.

We propose considering developing a **masterplan**. The masterplan is a step-by-step decision process which is undertaken on a rolling basis. The masterplan provides more adaptivity, long-term vision and coordination compared to the current offshore wind roadmap. It is not a replacement for the offshore wind roadmap, but it is in essence an expansion of the offshore wind roadmap, as it starts earlier and has a broader scope.

We recommend that a decision by the government should be made at three points in time (see also Figure 0-2):

1. A decision on which search area will be pre-developed could ideally be made approximately 20 years before the envisioned date of operation of the offshore wind farm.

2. An infrastructure decision could be made approximately 10 years in advance.The infrastructure decision will be made in close collaboration with the TSOs, industry and the wind sector and with due consideration of the considerations included in the joint offshore wind – industry roadmap (see section below). The ten-year time horizon for the infrastructure decision is an approximation. For example, realisation of an energy island will likely require several years longer. A radial electrical connection may also be possible within 8 years, and a hydrogen pipeline connection 3 to 6 years (depending on re-purposing or new-built). To account for these different variances, it is important to start 20 years in advance with the search area decision.

3. Five years before the date of operation, the government should define the site design and set up an allocation mechanism to tender the site to a project developer. Note, in case tenders for offshore wind and onshore electrolysis, the five-year window might be too short to realise a large-scale electrolyser, unless some activities are executed in parallel.

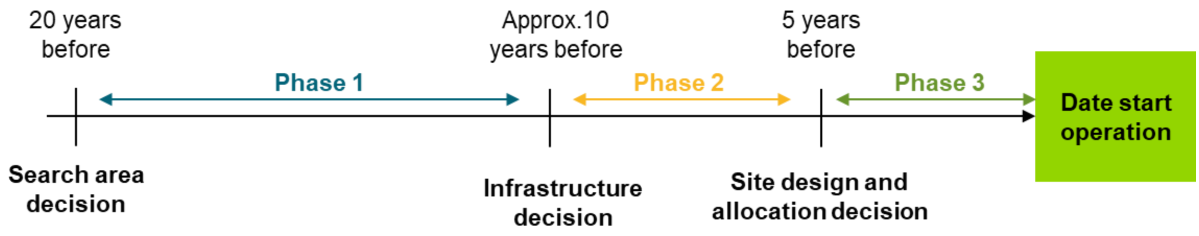


Figure 0-2 Masterplan overview

To ensure that the decisions are well-qualified, we recommend developing the masterplan by leveraging the most up-to-date knowledge and insights and weighing goals and stakeholder interests. Specifically, the government should consider:

- The required growth pace and absolute volumes of renewable electricity and green hydrogen that are needed to meet energy and climate targets.
- An analysis of green hydrogen and electricity demand and a projection of the growth of other generation assets besides offshore wind.
- The availability and supply of expected green hydrogen and electricity import and export volumes from other (European) countries
- Appraisal of interconnection opportunities (and value thereof) with neighbouring countries
- Modelling by the TSOs on onshore congestion, import/export volumes and flexibilities
- Insights into technically and economically feasible solutions via market consultations
- Technical factors such as the capacity of the search area, geography, offshore infrastructure abroad, proximity to offshore gas infrastructure and opportunities to repurpose.

The masterplan is set up with the goal of creating a long-term vision over the coming 20 years. However, should there be a need to adapt, each of the phases provides room for adaptation. With a view to 2030, this adaptivity is especially relevant. Due to the tight timelines, some infrastructure options, such as large-scale energy islands may not be timely feasible. Thus, adaptivity of the offshore infrastructure up to 2030 (and possibly 2031) is expected to be limited to infrastructure options with a fairly quick realisation period. This expectation has also been stated in the letter by EZK to parliament on VAWOZ.[15] Realising the 2030 electrolysis ambition requires setting a clear regulatory framework in the short term (i.e. in 2022), as large scale onshore electrolysers may take up to 8 years to realise. This timeline also implies that in order to coordinate the timing and location of large-scale electrolysers with the realisation of new offshore wind capacity, coordination should be done with offshore wind sites that are already in the current roll-out pipeline (including the additional 10 GW from the *Extra Opgave*).

The long-term market dynamics are important to consider and the proposed masterplan is intent on keeping and creating open and competitive markets for offshore wind/electricity and green hydrogen production.

[15] **https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557**

Joint offshore wind – industry roadmap 2040

The roll-out of offshore wind by 2040 will be driven by ambitious decarbonisation targets and the need to decarbonise all sectors of the economy. The industry sector is most relevant in the context of offshore wind, given the sector's large electricity demand volumes, significant electrification potential and the proposed RFNBO quota for industry. The roll-out of offshore wind after 2030 will almost solely depend on the pace and shape of decarbonisation of industry. The spatial preparation and realisation of offshore wind farms, landings, infrastructure, and projects for making industry more sustainable must be well aligned. Supply and demand cannot be developed separately. There are dedicated infrastructure programs for industry, a dedicated industry electrification roadmap and a dedicated roadmap for offshore wind. However, there is currently no joint program that focuses specifically on aligning the speed and incentives for electrification or green hydrogen use with the 2040 offshore wind roll-out.

To address this coordination need, a **joint offshore wind – industry roadmap 2040** could be developed. The goal of the roadmap should be to align the deployment schedule of new offshore wind projects with industry decarbonisation measures (direct or indirect electrification). An important success factor for the roadmap could be the effective use of expertise available within EZK to create coherence and alignment between the different policy fields. The roadmap should include a summary of the main targets, schedules and dates determined for industry and offshore wind by other policies. For example, it should include the volumes, locations and dates included in the offshore wind roadmap, the implications of *Maatwerk Afspraken*[16] for the largest GHG emitters as included in the coalition agreement and the volumes set out in the *Routekaart Elektrificatie*. The heart of the roadmap should be a joint yearly schedule for offshore wind roll-out and industry electrification and green hydrogen uptake until 2040. The offshore wind capacities to be installed need to be correlated with the projected electricity and green hydrogen demand by industry. The roadmap should also include information on the required electrical and pipeline transmission infrastructure. In this way, the network operators can formulate new investment proposals in accordance with the plans of industry, in line with the advice of the Taskforce Infrastructure Climate Agreement Industry and considering offshore wind developments. In effect, the joint roadmap can provide clarity and investment security for the market, align deployment timelines, ensure coordination, and ultimately enable decarbonisation and climate target achievement.

Chapter 6: Allocation mechanism

Once sites have been determined as part of the masterplan process, they can be allocated to market parties. The allocation mechanism determines the rules and processes according to which specific offshore wind site is allocated to a bidder (i.e. a project developer). It can also determine the rules according to which support payments are distributed to a bidder. For the allocation mechanism, a differentiation is needed between electrically connected stand-alone offshore wind farms, offshore wind farms and onshore electrolysis, and offshore wind and offshore electrolysis.[17]

Offshore wind

For electrically connected **stand-alone offshore wind**, there is currently a site-by-site decision by the Minister based on a market consultation on whether a certain site is tendered

[16] **https://www.kabinetsformatie2021.nl/documenten/publicaties/2021/12/15/coalitieakkoord-omzien-naar-elkaar-vooruitkijken-naar-de-toekomst**

[17] The allocation mechanism for configurations that include energy hubs has not been studied in detail in this report and deserves further attention.

with the option of support or without. Clarity on the allocation mechanism is provided relatively late in relation to the opening of tender rounds. This leads to uncertainty for the project developers, both with regard to timing of the decision as well as the actual tender procedure. Considering the expected scale-up of offshore wind capacities towards 2040 and the resulting high frequency of allocation procedures, a new approach which provides more immediate clarity may be required.

Therefore, the focus of this section is on developing options for allocation mechanisms. We recommend to pursue a **continuous allocation mechanism which is the baseline mechanism used for all offshore wind tenders.** Under a continuous allocation mechanism, there is a clear single award mechanism that would be used as a baseline, as opposed to a site-by-site decision on the allocation mechanism. Only in case of significant market changes would an alternative allocation mechanism be applied; in which case, this change must be communicated early on. Market consultations will be maintained for technical and economic insights, so that project developers are still enabled to share industry experience, to identify substantial market changes and help refine the tender specifics and site decisions.

Within a continuous mechanism, there is room for flexibility around the criteria used to select the successful bidder (i.e. the award criteria). Award criteria determine the order of bids. Besides a price-based selection, whereby projects are awarded based on lowest support bid or highest financial bid, qualitative criteria, such as innovation, are also feasible. Against the background of achieved cost reduction and zero-subsidy bids, the possible combinations of award criteria described above and potential future developments (either continuing the subsidy-free roll-out or failing with the subsidy-free roll-out and requiring support), we propose three options. These options are in line with the Offshore Wind Act. Options 1 and 2 are in accordance with the process of a comparative assessment with a financial bid and the competitive auction respectively. Option 3 is a combination of a competitive subsidy award procedure and a comparative assessment with a financial bid.

The three options are:

- Option 1: In line with the aim of continuing the subsidy-free roll-out, bidders are restricted to **zero-subsidy bids**. Bidders will be evaluated based on a **capped financial bid and qualitative criteria** (i.e. a comparative assessment with a financial component).

- Option 2: In option 2, bidders are also restricted to **zero-subsidy bids**. However, as an alternative to option 1, a larger emphasis on price could be implemented by **uncapping the financial bid** (i.e. a competitive auction). With an uncapped financial bid, a differentiation based on price is ensured and qualitative criteria are not required for differentiation.

- Option 3: In this **backstop option**, bidders are asked to fill in their required support level which could be positive or zero. In this primarily price-only approach, the support level is a result of the bids received with the lowest one winning (i.e. a competitive subsidy award procedure). In case of multiple zero-subsidy bids, the zero-subsidy bids will be evaluated based on a capped financial bid and qualitative criteria. Essentially, this option combines a competitive subsidy award procedure with – in case of multiple zero-subsidy bids – a comparative assessment with a (capped) financial bid.

The selection of a specific option depends on market conditions, policy objectives and the level of interest/competition. For the short-term, the current market situation makes continuation of zero-subsidy bids likely, which could be in the form of a capped financial bid with qualitative criteria (Option 1) or an uncapped financial bid (Option 2). We recommend careful consideration of market and supply chain conditions in selection a specific short-term option. Any changes over time – either on the general choice of the option, the bid cap or the qualitative criteria selected – should be communicated sufficiently early. For the longer-term, there are larger uncertainties with a view to the development of electricity wholesale market prices. In case of significant electricity price reductions, Option 3 may be considered as a backstop to stimulate the continued realisation of offshore wind. Conversely, in case of electricity price increases Option 2 may enable reducing windfall profits.

Offshore wind and onshore electrolysis

While the previous section focused on the allocation mechanism for stand-alone offshore wind farms, this section focuses on the allocation mechanism for offshore wind and onshore electrolysis. There is no established allocation mechanism for offshore wind and onshore electrolysis yet. In this section, we outline four different tender options and describe advantages and disadvantages of each. For electrolysers, there are substantial uncertainties that may influence the selection of an optimal allocation mechanism, such as the European Commission's Delegated Act supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by setting out appropriate rules for the production of renewable hydrogen from electricity (hereinafter referred to as the Delegated Act)[18]. For the eventual selection and detailed tender design, further discussion and analysis (e.g. on the impact of the designs on the cost of hydrogen production or on the duration of pre-development) are required.

We differentiate the options by the degree of coordination provided in the tender design:

- **Separate tenders:** Separate tenders are the least coordinated option as the tenders are separate for the offshore wind and onshore electrolyser scope each. The tender schedules would be defined in line with target achievement roadmaps of either offshore wind or onshore electrolyser development, and the available project pipeline. Separate tenders do not provide for alignment between demand and supply and reduce the ability to alleviate grid constraints.

- **Coordinated tenders** (in time and geography): Coordinated tenders allow for coordination without being excessively complicated for both the bidders and the government. This coordination is especially important in the beginning to allow for a significant market ramp-up. Coordinated tenders also create strong competition for both tender scopes. The risks for the project developers are higher in this option compared to joint or integrated tenders. More analysis is required on risk mitigation options, e.g. using Power Purchase Agreements (PPAs).

- **Joint tenders**: In a joint tender, a consortium between an offshore wind developer and an electrolysis project developer or a single developer that develops both assets participate in the tender. In the tender, support would only be made available to the hydrogen scope, as the Delegated Act is likely to prescribe that only electricity from additional, unsupported RES can be used to produce green hydrogen. Joint tenders reduce risks for the project developers, as both assets are included in one scope.

- **Integrated tenders**: In an integrated supply- and demand-side tender, a consortium between offshore wind project developer, electrolysis project developer and hydrogen offtaker would participate. Support would be paid to the hydrogen offtaker

[18] Please note that at the time of completing this study, the Delegated Act has not been published yet. All analysis included here is based on a leaked draft version from December 2021 and subject to review once the final Delegated Act has been published.

who gets reimbursement for the additional costs of green hydrogen. Integrated tenders can be quite a strong market intervention. However, they have value in the near-term as they ensure the ramp-up of green hydrogen demand and supply. We recommend against setting up a tender for integrated projects due to the expected low level of competition and the difficulty of comparing project concepts.

Integrated projects are usually tailored to a specific use case. This means that project designs differ significantly between projects, which makes a comparison as part of a tender evaluation difficult. Additionally, the number of integrated projects that would be similar enough to compete in a tender is expected to be low. Implementing a tender is not recommendable at low levels of competition. An alternative option could be to determine the support for integrated projects not via a tender but instead on a cost basis. Under a funding line, projects could apply for support based on their specific use case and business case. The project initiative would be assessed by an expert committee and eligible costs would be demonstrated according to the requirements set out in the funding line. The Coalition Agreement includes a company specific approach (*Maatwerk*) to decarbonise the 10 to 20 largest emitters in the Netherlands. A funding line for integrated projects may be an option to consider.

Offshore wind and offshore electrolysis

Large-scale deployment of offshore electrolysis on a gigawatt scale is envisaged to only take place after 2030.[19] Before this, first pilot projects may be realised.[20] This temporal distinction between near- and mid- to long-term also calls for a differentiated view on the allocation mechanism.

In the **near-term**, offshore electrolyser projects will likely require support to be economically viable and competitive against fossil-based alternatives such as grey hydrogen. In the allocation mechanism electrolysers, bidders must have the option to submit a support bid. Deploying electrolysers offshore is novel, and further insights regarding technical and economic performance of different options is required. The implementation of qualitative award criteria could facilitate an acceleration of progress in in the learning curve for this technology. As a result, a focus in the allocation mechanism on both the support bid and the quality of the projects is recommendable in the near-term.

However, such a price and quality combination must be feasible within the regulatory framework. At EU level, the revised Climate, Energy and Environmental Aid Guidelines require a maximum weighing for all other criteria (including qualitative criteria) besides the aid amount of 30%. This means that the support bid must determine at least 70% of the bid evaluation. At Dutch level, the *Kaderbesluit nationale EZK- en LNV-subsidie* states that the criteria and weighing of criteria can be set by Ministerial decree.[21] The *Besluit stimulering duurzame energieproductie en klimaattransitie* further provides the option for innovative wind tenders to combine subsidy level and other award criteria, which can be determined by ministerial decree.[22] The Offshore Wind Act currently provides four options for the allocation of offshore wind sites (see also section 6.1). Three options include other award criteria, one option is focused solely on support bid levels. None of the options entail a combination of support bids with other award criteria. An important point of uncertainty at Dutch level is that – even though there seems to be a general regulatory framework for the combination of award criteria - there is no precedence yet for the combination of support bids with other

[19] **https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557**

[20] The government has submitted a proposal for the National Growth Fund for a first demonstration project of hydrogen at sea. This project is several hundred megawatts in size and can possibly be realized before 2030.

[21] Article 17, **https://wetten.overheid.nl/BWBR0024796/2021-03-09#Hoofdstuk2**

[22] Article 24c, **https://wetten.overheid.nl/BWBR0022735/2020-11-01#Paragraaf3_Sub-paragraaf3.4**

award criteria for commercial scale offshore wind farms. This uncertainty warrants further discussion and analysis.

After 2030, with the ramp-up of the green hydrogen market, supply-side support may be reduced over time in favour of demand-side support. Over time, zero-subsidy bids may become feasible. In that case, a differentiation of bidders only by quality could be feasible. In case of very positive market developments, even a combination of qualitative criteria and a financial bid could become feasible. For these developments, we recommend the use of competitive tenders.

Chapter 7: Tender product & site definition

Tender product

For (stand-alone) **electrically connected offshore wind** farm developments, we recommend following much of the current process including the one-stop-shop principle, offering:

- Exclusive rights to construct and operate the wind turbines and their associated balance of plant[23] within the site boundaries
- Permits to construct and operate the wind farm
- Access to offshore electricity transmission infrastructure
- In case subsidy-free offshore wind roll-out fails, grant (*beschikking*) of a support payment

The tender product for joint developments of **offshore wind and onshore hydrogen** depends on the allocation method followed. The tender product is similar to that of an "offshore wind only" tender. In case of joint and integrated tenders, the offshore wind scope is combined with the electrolyser scope in a single tender. In case of a separate tenders, the offshore wind tender should include the possibility of the support scheme backstop. In case of a coordinated tender, a joint tender or integrated tender, it is expected that a support backstop for the wind farm cannot be part of the tender product. This is due to the expectation that the Delegated Act on sustainability criteria may disallow the contracted renewable electricity generator receiving support, as a criterion to qualify the produced hydrogen as an RFNBO. In terms of land rights and permits, there is a challenge in providing a similar type of one-stop-shop package for the electrolyser scope, compared to the offshore wind scope. We recommend that the winning electrolyser bidder is made responsible to obtain land rights and permits. As a consequence, it is not part of the tender product. It should be noted that due to the footprint of a gigawatt scale electrolyser, the number of suitable locations is limited. This could pose a risk of limited competition. For similar reasoning as the land rights and permits for onshore electrolysers, we recommend making the electrolyser developer responsible for the connection from the electrolyser to the onshore high voltage substation owned by TenneT. However, considering the large electrolyser capacities expected, it may be sensible for TenneT to realise new onshore substations in anticipation of the realisation of onshore electrolysers. For integrated tenders, we recommend providing a subsidy for the actual decarbonisation of the final offtaker. A similar rationale applies as above, to only provide support to one actor to avoid stacking subsidies. This requires a demand-side support instrument, such as a carbon contract for difference (CCfD).

In case of joint developments of **offshore wind and offshore electrolysis** various project configurations are feasible. In case of **integrated electrolysis**, the tender product can be

[23] The balance of plant in this model includes the foundation and inter-array cables.

analogous to the tender product of electrically connected offshore wind farms. In case of **centralised electrolysis**, the tender product may either include or exclude the rights and permits to realise and operate electrolysers. This should follow the decision on the governance model (roles & responsibilities) of offshore electrolysis. Based on our recommendation to include the ownership and operational responsibility to the wind farm developer, we recommend to also include the rights and permits to realise offshore electrolysis on a shared centralised location in the tender. A separate bilateral agreement with the owner/operator of the shared substructure will be needed, this can be negotiated (based on a clear tariffs and conditions known at the time of the tender) after the tender award. For a setup where centralised electrolysis is placed on a platform that is not shared, it is sensible to include it in the wind developer scope. In case of a setup that combines electricity and hydrogen transmission, the capacity allocation mechanism and market models warrant a separate investigation.

Site definition

As a consequence of a one-stop-shop mechanism, and through inclusion of the provision of permits in the tender product, the wind farm sites need to be defined by the government.

Regarding the wind farm capacity for **electrically connected wind farms** we recommend that the capacity of future wind farm sites should grow, in pace with market appetite, first from 1 GW sites to potentially 2 GW sites later on (the Hollandse Kust (west) tender can provide insight into the market appetite for larger sites). We advise against larger sites in the short term, due to the increased risk in case of a failed development. Regarding the density, we assess 10 W/m^2 to be at the high end compared to offshore wind realised in other countries. Scarcity of available space at sea due to other users and ecological impact may be a reason to increase density. However, considering the density assumed for Ontwerp Programma Noordzee is already high, we argue against increasing the density in the short term, but developments in wind turbines should be followed closely by EZK and RVO. In setting a minimum wind turbine capacity, we recommend considering both ecological impact (a larger capacity results in fewer turbines, which reduces ecological impact), as well as providing the industry room to optimise. An increase in minimum capacity should be tested with the market through consultation, to ensure it does not result in a reduction in competition.

For **offshore wind farms including electrolysis**, we recommend greater flexibility in the capacity of wind farm sites. A minimum wind farm capacity can be set to ensure the seabed (and possibly a shared offshore infrastructure) is used efficiently. In case of integrated offshore electrolysis, wind turbines will be redesigned to achieve a new economic optimum between rotor diameter and capacity. The expectation is that this may result in a higher optimum density. This may increase the total rotor surface area within the wind site, and thus ecological impact of such a change needs to be considered.

In case of centralised offshore electrolysis, a combined infrastructure that allows transmission of both hydrogen and electricity could provide additional (net) benefits, compared to hydrogen only. In the study Systeemintegratie wind op zee 2030-2040, we conducted an approximation of the net benefit of adding a hybrid electrical connection to a centralised electrolysis island. The main take-away was that there is no static optimum ratio, as the value is driven by supply and demand.

It may be necessary to have a site definition that is not technology neutral to optimally use a wind farm area (e.g. requiring a governmental choice between integrated or centralised electrolysis). From a perspective of granting the market room to select the optimum technology, a technology neutral site definition is preferrable. In some cases, the infrastructure configuration will predetermine the possible technologies, resolving the dilemma. In general, we recommend tracking technical and economic developments of offshore electrolysis, to assess whether a suboptimal site definition is warranted to achieve technology neutrality.

Realisation period and permit duration

For offshore wind, there is currently under SDE++ an established realisation period of five years with monthly penalties for delayed delivery that we recommend maintaining for the time being. Connection to HVDC infrastructure and increasing market volatility and supply chain bottlenecks may be reasons to increase the realisation period. For offshore wind and hydrogen projects, realisation periods are more uncertain as large-scale electrolyser projects are yet to be realised. Estimates that we have gathered from industry differ, but developers of large-scale projects indicate that the realisation period could be up to 8 years. This would imply that in order to realise large scale electrolysis by 2030, decisions regarding the policy framework should be made by the end of this year. For offshore wind and hydrogen projects, we recommend establishing an expert group which could inform EZK and RVO in setting a realisation period which is achievable yet tight enough to ensure project realisation.

Permit durations should follow developments in the operational lifetime of wind farms. Some developers have indicated that 35 years operational lifetime is feasible and see possibilities to extend this further. We recommend continuing dialogue with the industry to have the latest insights when setting permit durations. In general, more clarity at time of award on the duration, in contrast to offering uncertain permit extension options, is preferable to investors, as this provides developers the opportunity to make provisions in their design and asset management approach. This should be weighed against possible downsides of providing a longer claim to a scarce area, such as e.g. technological advancements that would enable providing greater societal benefits from the same area.

Chapter 8: Support policy instruments

The roll-out of offshore wind in the Netherlands has been a success story thus far. Starting in 2016, it resulted in a steady pace of successful tenders, with rapid cost reductions resulting in subsidy-free projects in two years. This means that project developers are entirely reliant on other sources of revenue (i.e. not on subsidies) to maintain a viable business case.

Investments in offshore wind farms which have such merchant risk exposure require a long-term view on a well-functioning market. When additional supply of renewable energy sources outpaces demand, electricity wholesale market prices might fall. Creating demand through electrification of current energy use or creating additional demand, either directly or indirectly (e.g. electrolysis), can stabilise electricity prices. Possible policy instruments for the demand-side include quotas, investment support for retrofitting processes, Carbon Contracts for Difference (CCfDs), CO_2 pricing, and the phase-out of fossil energy. The existing EU Emissions Trading System (ETS) already favours this development. The proposed RFNBO quota for industry provides a further demand stimulus to be realised by Member States.

Offshore wind project developers have underlined the importance of ensuring sufficient demand rather than supporting supply. The main reason may lie in the effects of a subsidy on the market. Most project developers currently in the market have their assets built on a merchant basis, hence without support payments. In case the subsidy-free approach fails, and support is reintroduced, the portfolio may be extended to supported assets. While the payment of support helps to secure the revenues for the subsidized asset, it will at the same time lower the revenues to be earned for the assets without subsidy. Due to the support scheme, additional RES capacity is being pushed into the market, thereby lowering prices, which the market itself would not have warranted if the market equilibrium of supply and demand was the only consideration.

The government's focus should thus be on ensuring the right framework conditions for a continued subsidy-free offshore wind roll-out rather than preparing a support scheme for offshore wind. Direct RES Power Purchase Agreements (PPAs) are a financial instrument for project developers to hedge the revenue risks. PPAs are not a policy instrument per se but could benefit from favourable regulatory framing. We argue that besides some no-regret policy options, PPAs should not be forced onto demand with regulatory measures. The main argument for this is that strong intervention in the PPAs market can disturb the PPA price formation and distort the playing field. Besides this, PPAs will likely be in high demand by electrolyser operators as the Delegated Act is likely to request that on-grid electrolysers have a PPA with a new and unsupported renewable energy plant.

Whether support payments are required for offshore wind projects depends on various factors such as coordination risks, site quality, proximity to shore, whether grid connections are included in the bid or not, permitting procedures, expectations on future wholesale market prices, and marketing routes that may transfer some of the revenue risks away from the producer (such as in PPAs). If these factors are not favorable for further subsidy-free development, a support scheme may be necessary.

For a dedicated **offshore wind support scheme**, we recommend using a sliding feed-in premium (FIP). Sliding premiums allow for a gradual evolution towards greater market integration, while under a Contract for Difference entailing a payback requirement, bidders are incentivised to bid a fully cost-reflective price and thus market price risks remain with the society rather than project developers. The current SDE++[24] pays its support out as a sliding FIP. In case the existing support scheme is reformed, no changes to the form of support are required based on our recommendation. In case a new support scheme is set up, we recommend implementing as the form of support a sliding FIP.

For a supply-side **hydrogen** support scheme focused on jointly developing offshore wind and hydrogen, we recommend implementing a combination of investment support and operating support to ensure that electrolyser projects can be realized and operated. Investment support could phase out over time as CAPEX reduces due to expected cost reduction of electrolysers. In the longer term, supply-side support may move to demand-side policies (e.g. quotas), as a liquid market (incl. infrastructure) develops.

Chapter 9: High-level legal feasibility check of recommendations

In this study, we checked the legal feasibility of recommendations against key Dutch and European legislation.

The proposal for the *Energiewet* does not yet provide a clear regulatory framework for offshore electrolysis and offshore hydrogen transmission and also does not consider the recently published revision of the EU gas markets and hydrogen directive and the gas markets and hydrogen regulation. There may be an opportunity to revise the act (as indicated in the *Memorie van Toelichting*). The proposed act does provide for the recommended governance of offshore electricity infrastructure, which follows the current approach. The *Wet Windenergie op Zee* provides a feasible regulatory framework for electrically connected offshore wind farms. Offshore electrolysis is possible within the act, though the definition of connection point (*aansluitpunt*) may warrant modification. The act does not provide for allocation mechanisms where wind is combined with onshore electrolysis.

The *Kaderbesluit Nationale EZK- en LNV-Subsidie and Besluit Stimulering Duurzame Energieproductie en Klimaattransitie* may pose issues for joint and integrated tenders, as it

[24] Stimulering Duurzame Energieproductie en Klimaattransitie (SDE++)

may not be possible to account for the full scope as direct, subsidisable cost. The SDE++ does not provide for investment support, which may be important for near term support of electrolysis.

Many pieces of EU legislation have been revised as part of the Fit for 55 Package published in 2021. Three pieces are especially relevant in the context of this project: the Renewable Energy Directive II (RED II), the gas markets and hydrogen directive and the gas markets and hydrogen regulation. Offshore hydrogen networks are mentioned specifically in item 66 of the recitals of the gas markets and hydrogen directive. Equally onshore and offshore, regulated third-party access on the basis of regulated access tariffs should be the default rule in the long-term. In order to ensure the necessary flexibility for operators and to reduce administrative costs during the ramp-up phase of the hydrogen market, Member States have the option to allow the use of negotiated third-party access until 2030. The vision developed here considers these targets, signals, and considerations. There is no red flag identified. Overall, on a high-level, the recommendations made in this study are also in line with the revised Climate, Energy and Environmental Aid Guidelines. The recommendations made in this study were developed with the requirements of the Delegated Act in mind. However, the Delegated Act is still being drafted at this moment. Once a final version has been published, the legal feasibility check should be repeated.

Chapter 10: Conclusions and discussion

Throughout this report, we have conducted studies and provided analyses for specific cases that are envisaged for the future offshore wind roll-out. Based on this work, we can formulate five high-level observations:

- **Observation 1: 2040 is closer than it may appear and 2030 is essentially just around the corner.** Considering the infrastructure and onshore electrolyser lead times of 10-12 and 7-8 years respectively and the ambitious decarbonisation targets, policymaking is required this year.

- **Observation 2: Coordination and infrastructure challenges warrant a strong involvement by the Dutch government**. Considering the identified challenges and the risk mitigation potential of the government, we recommend for a strong coordinating role of the government (e.g. in the masterplan and joint roadmap).

- **Observation 3: Hydrogen could become a cornerstone of the 2040 offshore wind roll-out**. If the Fit for 55 Package is adopted as proposed, industry will require significant hydrogen volumes. Offshore wind is poised to be a major contributor through the production of renewable electricity, and potentially at a later stage offshore production of hydrogen.

- **Observation 4: Developments in the Netherlands are highly influenced by policy developments at EU level.** Three are especially relevant – the RED II revision, the gas markets directive and regulation and the Delegated Act on the sustainability criteria for RFNBOs.

- **Observation 5: The offshore wind industry wants to make the offshore wind roll-out a success – without support payments to wind farms.** The wind industry parties involved in this study have been outspoken and underline the importance of setting the right framework conditions so that offshore wind can succeed without support payments.

While this study discusses a broad range of topics, there are some topics which were out of scope and thus not considered in detail. These limitations and fields for further analysis are made transparent in chapter 10.

The ambitious 2030 decarbonisation targets require action by policymakers this year. Therefore, we conclude this study with an overview of recommended next steps for policy makers:

1. **Initiate processes for the masterplan**: A necessary next step for the masterplan would be to engage with all relevant actors on the idea of the masterplan to create buy-in from TSOs, the wind sector and industry. Start by further defining the activities in the different phases and the decision-making processes to follow. Determine applicability to ongoing offshore wind developments.

2. **Start conversations for the joint offshore wind – industry roadmap 2040:** A crucial element of the joint roadmap is the coordination of the different actors. The government should identify in a first step the relevant actors (TSOs, industry, wind sector, local representatives, government representatives) and start the engagement with these actors. In a second step, the government could start summarising the main targets, schedules and dates determined for the development of industry decarbonisation efforts and offshore wind by other policies. This would form the basis for the joint yearly schedule for offshore wind roll-out, industry electrification and green H_2 uptake until 2040. Within the joint roadmap, we recommend investigating acceleration opportunities for permitting and infrastructure realisation timelines.

3. **Define national hydrogen production target:** With the caveat that negotiations on the Fit for 55 package are still ongoing, a discussion on the required hydrogen volumes and the shares between imports and domestic production should be initiated with the view to defining a national hydrogen production target.

4. **Provide clarity on the future electricity and hydrogen market set-up:** Market parties require a view on the future market set-up which considers international and cross-border developments. To provide such clarity, the government should communicate its expectations for the future market set-up.

5. **Conduct a detailed study of a future offshore hydrogen network:** This study would provide insights into the required timing of realising an offshore H_2 network, technical and commercial specifications of such network, and provide insights into the opportunities of reusing existing pipelines.

6. **Decide on governance model(s) for offshore hydrogen infrastructure:** Before concluding on the best-suited governance model(s) for offshore hydrogen infrastructure, further discussion on advantages and disadvantages of the options is needed. This requires involvement of all relevant actors and due consideration of the regulatory framework set at EU level and experiences made in other sectors.

7. **Carry out in-depth legal feasibility check:** The high-level legal feasibility check was not performed by lawyers and should be repeated in-depth by the relevant legal experts. A review of the assessment made here is also needed once the Delegated Act has been published.

Part 1: The need for policy intervention

This first part of the report sketches out the need for policy intervention. First, **chapter 1** describes the background against which this report was drafted – the offshore wind roll-out in the Netherlands thus far, the relevant energy and climate policy targets, and the goal of this study. **Chapter 2** then looks at the challenges the offshore wind roll-out may face going forward until 2040 and highlights three key challenges to be addressed and mitigated through policy. In light of the identified challenges, the current approach to offshore wind roll-out is examined in **chapter 3** with a view to identifying those elements that are contributing to the current successful roll-out and should therefore be maintained for the future. Lastly, **chapter 4** looks at the changes the offshore wind roll-out may be subject to up to 2040. A particular focus here is on the changes in electricity and green hydrogen demand, infrastructure, technologies and project configurations for offshore wind. The chapter also identifies key trends that will shape the offshore wind roll-out towards 2040.

The analysed political context, challenges, success factors and relevant changes, are the foundation for the policy options discussed in part 2 of this report.

1. Objective of this study and approach

Dutch offshore wind roll-out and policy framework

The Dutch offshore wind sector kicked off with the start of the construction of offshore wind farm Egmond Aan Zee in 2005, five years after the first offshore commercial wind farm was commissioned in Denmark. Soon after, the Prinses Amalia wind farm followed. The Netherlands was an early mover in offshore wind, following in the footsteps of Denmark and the UK. After these early successes, it was only in 2010 that a second subsidy round (under the SDE subsidy regime) was opened for offshore wind developers. The wind farms Gemini (initial developer: BARD) and Luchterduinen (developer: Eneco) received subsidies from the SDE budget.

The first capacity targets were defined in 2013 with the ***Energieakkoord***. The goal was set to achieve 4.5 GW of offshore wind by 2023 while reducing cost levels with at least 40%. Going forward, the roles were also adapted - the Dutch government would lead the spatial planning and permitting process. The national TSO TenneT was given the mandate to build the offshore electrical transmission assets to connect new offshore wind farms to the grid. In doing so, the Minister set the scene for a roll-out under this new regime.

After the above-mentioned early mover projects and since the 2013 approach, deployment has taken off and costs have dropped dramatically. Starting in 2016, this new regime resulted in a steady pace of successful tenders, with rapid cost reduction from 72.7 €/MWh to subsidy free projects in the space of two years, and fast realisation times between tender award and a fully operational wind farm (4-5 years for Borssele I&II and III&IV). At the beginning of 2022, 2.5 GW of offshore wind farms are operational and additional ~2.2 GW have been awarded in competitive tenders.

In 2019, the Dutch Climate Agreement led to the creation of the **Offshore Wind Energy Roadmap 2030**, setting a clear path to realise 10.6 GW by 2030[25]. In the same year, the Minister of Economic Affairs and Climate Policy tasked the steering committee '*Extra Opgave*' to assess if additional renewable energy generation is needed to meet the more stringent GHG reduction of -55% that was adopted by the EU. The steering committee advised the Minister to make preparations that enable a maximum additional capacity of offshore wind of +10 GW by 2030 (i.e. in addition to the Roadmap 2030).[26]

There are no offshore wind deployment targets beyond 2030 in place in the Netherlands. The **North Sea Program 2022-2027** seeks to designate offshore wind farm zones that enable an additional 27 GW on top of the ~11 GW of the Offshore Wind Energy Roadmap 2030. The North Sea Energy Outlook indicates a range of 38-72 GW of offshore wind by 2050.

Overarching policy goals

With the European Green Deal, the EU and its Member States have committed to achieving climate neutrality by mid-century and to adjust the GHG emission reduction target for 2030 from 40% to 55%. In the **coalition agreement**, the new Dutch government has agreed to

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[25] The Offshore Wind Energy Roadmap 2030 envisages 3.5 GW (in 2023) and 6.1 GW (in 2030) in addition to the then existing wind farms (1 GW), making a combined total of 10.6 GW.

[26] Klimaatakkoord (2021), Stuurgroep Extra Opgave, **https://www.klimaatakkoord.nl/documenten/publicaties/2021/04/13/stuurgroep-extra-opgave**

focus policy on greater reductions, which will amount to approximately 60% in 2030.[27] After 2030, the aim is to achieve a 70% reduction by 2035 and 80% by 2040.

To meet the 2030 GHG reduction target, the European Commission has published the **Fit For 55 package** in 2021. While the proposals by the European Commission are yet to be negotiated and agreed upon by the Member States, they clearly show the level of ambition expected going forward. For example, the package provides stimulus for an accelerated roll-out of renewable energy sources. The proposed revision of the **Renewable Energy Directive II (RED II)** sets an increased target to produce 40% of energy from renewable sources by 2030 (current EU target: at least 32% renewable energy by 2030). The RED II revision proposal also includes a new sub-target for the use of RFNBOs in industry[28]. According to the proposal, until 2030, 50% of hydrogen[29] and derivatives used in industry must be renewable. While the target focuses on industry, the target achievement obligation is on the Member State level. Hence, the Dutch government must create the framework conditions for target achievement by national industry. Please note that while we make reference to this proposed target here throughout the report, the proposal is still under negotiation at EU level and may as a result of these negotiations be adapted. Also note, that imports may play a significant role for target achievement in 2030.

In April 2020, the Dutch Government published the **Government Strategy on Hydrogen**.[30] In it, reference is made to the National Climate Agreement which includes an ambition to scale up electrolysis to approximately 500 MW of installed capacity by 2025 and 3-4 GW of installed capacity by 2030. The State Secretary of the Ministry of Economic Affairs and Climate Policy estimated that if the Fit for 55 RFNBO targets would become binding, this may result in a green hydrogen demand of 14 – 31 TWh and that it would require 4 to 12 GW of electrolysis to supply this demand.[31] In the same letter to parliament, the State Secretary indicated this would require at least 6 GW of offshore wind to facilitate this hydrogen production, without detriment of decarbonisation of other electricity use.

Study objective and scope

To ensure the achievement of the many above-mentioned targets, it is important to start preparing for the further roll-out of offshore wind now. Moreover, it is important to inform the market actors, supply chain and TSOs in time about what the roll-out will look like, so that the necessary preparations can be made. The additional tasks before 2030 and the further roll-out of offshore wind energy after 2030 must be considered in conjunction with each other, which requires insight into the roll-out of offshore wind energy up to 2040. The offshore wind roll-out until 2040 will face new challenges and risks. Some of these challenges were already identified by Afry in a report from 2020[32], others are examined in

[27] Source: **https://www.government.nl/binaries/government/documents/publications/2022/01/10/2021-2025-coalition-agreement/2021-2025+Coalition+agreement.pdf**

[28] Another RFNBO sub-target of 2.6% was proposed for final energy demand in transport. Also, a minimum target of 0.7% of synthetic kerosene in final energy demand in aviation (the total sustainable aviation fuels (SAF) target is 5%) was proposed.

[29] Please note that when we speak of hydrogen throughout the document, we always mean green/renewable hydrogen produced with electricity from renewable energy resources.

[30] Rijksoverheid (2020), Government Strategy on Hydrogen, **https://www.government.nl/binaries/government/documents/publications/2020/04/06/government-strategy-on-hydrogen/Hydrogen-Strategy-TheNetherlands.pdf**

[31] **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof**

[32] Afry (2020), The business case and supporting interventions for Dutch offshore wind, **https://www.klimaatakkoord.nl/binaries/klimaatakkoord/documenten/publicaties/2020/03/05/rapport-afry_the-business-case-and-supporting-interventions-for-dutch-offshore-wind_march-2020/AFRY_The+business+case+and+supporting+interventions+for+Dutch+offshore+wind_March+2020+Single_Final.pdf**

more detail in this report. As a necessary consequence of these challenges, the future roll-out of offshore wind farms will require a **new approach**. It will have to be on a larger scale, focused on system integration with the onshore energy system and more internationally connected. The further roll-out of offshore wind farms must be in line with demand developments on land (electrification and production of green molecules).

The **main objective of this study is to obtain an overview of the possible policy options and instruments for a new approach to offshore wind energy.** The study focuses on adapting or supplementing the instruments used in the current offshore wind energy approach. The focus is primarily on offshore wind, but due to its significant role in the future, green hydrogen is also considered in the report. The focus is not on the technical challenges of offshore wind energy in the energy transition, but on a strategic answer to the challenges of the future deployment of offshore wind energy. The research should translate these strategic questions and answers into options for concrete instruments and provide insight into the advantages and disadvantages of these options. The study should also identify relevant red flags with a view to the legal feasibility of recommendations.

Study approach

Guidehouse was tasked by the EZK and RVO to work on the **Policy options Offshore Wind 2040** research project (*onderzoek instrumentarium t.a.v. uitrol wind op zee 2040*). Leading up to this final report, Guidehouse had developed four discussion notes, each with a different view on elements of the offshore wind 2040 vision. A first discussion note focused on the value chain and relevant challenges and risks, a second discussion note focused on identifying the drivers of success of the current approach and distilling those that should be maintained for the future, the third discussion note examined governance questions in the context of governance and lastly, the fourth discussion note focused on site selection, allocation mechanism and support instruments. The insights from these discussion notes form the basis of this final report.

The discussion notes formed the basis for periodic meetings with a working group. This working group consisted of representatives throughout the offshore wind value chain. During the working group meetings, the content of the discussion notes was discussed, and participants were given the opportunity to provide their critique and additions. This final report is the result of this iterative process.

To meet the objectives of the study, Guidehouse used – next to the input from the working group meetings – literature research, bilateral interviews with working group members, expert exchanges with EZK and RVO, insights from other countries (e.g. Denmark, UK, Germany, Norway) and the multi-disciplinary in-house expertise of Guidehouse.

This report is structured as follows:

- **Part 1**: The purpose and objectives of the study are introduced in chapter 1, the current success factors are reflected upon in chapter 2, the key challenges to the offshore wind value chain with a view to 2040 are discussed in chapter 2 and the key changes for offshore wind up to 2040 are introduced in chapter 4.

- **Part 2**: The second part of the report focuses on adapting or supplementing the instruments used in the offshore wind energy approach, including governance (chapter 5), the allocation system (chapter 6), the definition of the tender product (chapter 7) and support instruments (chapter 8).

- **Part 3**: A high-level check of the legal feasibility of recommendations is made in chapter 0. The report is concluded in chapter 10 with a discussion and next steps.

2. Key challenges for the offshore wind value chain

Policy makers and industry representatives alike want to ensure that the roll-out of offshore wind until 2040 is successful. To ensure such success, stakeholders need to understand the challenges that the roll-out until 2040 may face. In this regard, the following challenges were already discussed:

- The working group has aligned on a guiding principles document, which also includes a review of key challenges. Among the listed challenges are value chain dependency of investments, adaptiveness of approach to roll-out, business case for offshore wind and investment security, (inter)national developments, infrastructure at sea, and lastly, time.

- In a study for EZK, Afry has identified further challenges, however only for the time horizon until 2030.[33] Challenges according to the analysis are the 'cannibalisation effect' (i.e. the proportion of the baseload price that a wind or solar generator captures is below 100%), the availability of financing, the unknown speed of electrification of heat, industrial processes, and transport and the viability of merchant wind farms in a future without support payments.

We take these considerations as a starting point for our analysis and uncover more challenges, risks, and interdependencies.

2.1 Risks in the value chain

Relevant parts of the offshore wind value chain are the supply side including the offshore wind project developers, the demand side, including i.a. industry, as well as the infrastructure part, including the electricity and H_2 pipeline companies. Each of the three parts of the value chain requires specific pre-conditions that need to be in place. For the supply side these are: sufficient revenues, sufficient demand, infrastructure availability, sufficient investment capital, maritime space, policy stability and clear responsibilities for planning interfaces.

Also, sufficient human capital is required to implement new investments.[34] This holds true especially for the supply chain but also for the governmental bodies, where capacity is required e.g. for fast permitting. In order for the envisioned offshore wind capacity increase to function, all the key actors in the supply chain need to make investments. For example, without an increase in turbine manufacturing capacity, the amount of new offshore wind farms cannot be realized for a lack of essential components.

For each pre-condition, there are risks that could hinder investments. For example, sufficient revenues may be endangered by the following potential risks:

- Offshore wind capture prices may be structurally lower than the levelized cost of electricity

[33] Afry (2020), The business case and supporting interventions for Dutch offshore wind, **https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/publicaties/2020/03/05/the-business-case-and-supporting-interventions-for-dutch-offshore-wind/The+business+case+and+supporting+interventions+for+Dutch+offshore+wind.pdf**

[34] New higher education curricula and specialised training focused on employment in the offshore wind sector have been developed to anticipate on the need for 12,000 employees who will work in the Dutch offshore wind sector by 2030: **https://www.maritiemland.nl/news/the-netherlands-your-partner-in-offshore-wind/**

- Other revenue streams may not materialise or are of lower value than expected (ancillary services)
- There may be increasing hours where total renewables supply exceeds total demand, resulting in negative prices[35] and high volatility
- The bidding zone may be reshaped
- Fossil power prices may be too low due to hidden subsidies to conventional sources[36], missing internalization of external costs, oversupply or due to other reasons
- Offshore wind full load hours may reduce with increasing installed capacities[37]

2.2 Key challenges

Analysing the risks to further offshore wind roll-out, we identify three key challenges:

1. Firstly, there is a **business case challenge**. Offshore wind farm investors may face increasing challenges in the future with regards to the viability of the business case, for instance due to diminishing revenue streams and risk of delayed connection. The risk of uncertain revenues is influenced by several factors not necessarily in the hand of developers/operators (low or even negative power prices on the spot market, development of (renewable) electricity supply and demand, price of the EUAs under the EU ETS, etc.).
2. Secondly, the discussion note identified an **infrastructure challenge**. Infrastructure is required to connect supply and demand. Risks emerge with regards to the characteristics of future on- and offshore infrastructure, coordinating the electricity and future H2 infrastructure, financing of infrastructure investments and cost recovery, timely availability of new assets (subject to long lead times), congestion issues and onshore grid reinforcement coordination, and uncertainty regarding location of new demand. Risks also arise out of coordinating interconnection and grid expansion schedules with neighbouring countries.
3. Thirdly, there is an **integration and interface challenge**. Risks regarding the integration and governance of value chain interfaces emerge towards 2040 because integration increasingly happens across sectors. With direct and indirect electrification, the boundary of the electricity sector is expanded to include heating, mobility, and green hydrogen as an energy carrier. This results in interdependencies between these sectors, which in turn poses risks that issues in one (e.g. realisation of

[35] Negative prices don't only occur when total RES supply exceeds total demand but also when fossil generators accept negative prices for staying in the system (e.g. due to ramping costs, must run, etc.).

[36] The government of the Netherlands produced a self-report identifying 13 individual fossil-fuel subsidy measures in the form of tax exemptions or reductions, benefitting both the production and consumption of fossil fuels. Together, they amount to at least EUR 4.48 billion of revenue forgone for the government. IEA (2020), The Netherlands' Effort to Phase Out and Rationalise its Fossil-Fuel Subsidies, **https://www.iea.org/reports/the-netherlands-effort-to-phase-out-and-rationalise-its-fossil-fuel-subsidies**

[37] Agora Energiewende, Agora Verkehrswende, Technical University of Denmark and Max-Planck-Institute for Biogeochemistry (2020), Making the Most of Offshore Wind: Re-Evaluating the Potential of Offshore Wind in the German North Sea, **https://static.agora-energiewende.de/fileadmin/Projekte/2019/Offshore_Potentials/176_A-EW_A-VW_Offshore-Potentials_Publication_WEB.pdf**

electrolysis capacity or electrification of heat) impact the other (e.g. finding off-takers for renewable electricity).

2.3 Risk mitigation abilities

A success factor of the current Dutch approach to offshore wind roll-out has been the focus on de-risking. As a rule, risks are best allocated to those actors best able to cope and mitigate the risks. Hence, for the identified challenges, an assessment of whether the affected parties can mitigate or bear the risks they face or whether the government should intervene with risk mitigating measures is needed.

1. **Business case challenge**

The business case challenge mostly affects the project developer, the demand-side (through the electricity price) and the government.

The **project developer's** business case faces the largest risks, thus they are the most affected actor. Their mitigation measures include entering long-term offtake agreements with energy consumers (e.g. in the form of PPAs), decreasing the levelized cost of offshore wind electricity to reduce unprofitable gaps or creating flexible demand with storage or electrolysers. With regards to PPAs some underlying questions need to be addressed regarding the creditworthiness of counterparts, the actor diversity of the offtake market (PPAs work for large actors, but can how can you integrate smaller actors?) and the liquidity of the PPA market.

How the business case challenge is met has important implications on the **demand side.** Particularly for (electrified) energy intensive industry the electricity price is crucially important. Taking green hydrogen production as an example, its operating costs (largely made up of the electricity price) account for around two-thirds of the green hydrogen production cost. To become cost-competitive against fossil-based alternatives, the production cost needs to be reduced substantially. Reducing the electricity price on the supply side (through cost reduction of offshore wind) could be a key to achieving such reduction. The risk of volatile (and higher) prices also can be mitigated by the demand side through long term offtake agreements such as PPAs. However, that means that they will take the price risk of over-paying, so it is a question to what extent they are willing to do that.

The **government** has a significant interest in ensuring that the business case challenge is mitigated as otherwise the envisioned offshore wind roll-out until 2040 would be endangered. The government could mitigate the business case challenge by strengthening the EU ETS (or implementing or increasing carbon pricing), implementing a support scheme for offshore wind, introducing public risk coverage facilities, e.g. for the default risk of PPAs, reducing or maintaining low pre-qualification barriers for renewable energy sources in ancillary service market to provide access to additional revenue streams or by implementing grid expansion measures to reduce congestion and re-dispatch. In case prices drop too far and more quickly than the reduction of costs, and other measures cannot be found, the Netherlands may have to revert to a subsidy scheme. Such a change would however fundamentally disadvantage current projects realized without support. This could in turn have negative implications on investor certainty.

2. **Infrastructure challenge**

The infrastructure challenge essentially affects all actors, as infrastructure is always required to connect the actors in the offshore wind value chain.

The **infrastructure companies** are at the core of the infrastructure challenge. In principle, they are able to mitigate risks that fall into the realisation and operation of the grid and potentially future hydrogen storage. For risks outside of the regular scope, infrastructure companies have few mitigation options available.

- One mitigation could be to increase the scope for anticipatory investments. However, for these investments to be credible, infrastructure companies need to understand where demand and supply may be located. Clarity on future volumes must come early, due to long lead times. While the marine spatial plans provide good insights for the supply side, closer coordination may be required for the demand side. Any investments require approval from the regulator thus the infrastructure companies cannot fully decide on such mitigations in isolation.

- Another mitigation option could also be to reserve sufficiently wide offshore corridors for transport with electricity cables and/or hydrogen pipelines. Designating offshore sites large enough to enable an independent business case for transport with hydrogen or electricity and to prevent existing infrastructure from being locked in may also be considered.

- From a systems integration or physical constraints perspective, risks may also be mitigated by building electrolysers. If the electrolyser is built offshore (centralised a platform or an energy island, or within each wind turbine), pipeline infrastructure is required for the transport to shore. If alternatively, the electrolyser is built onshore close to the landfall, a cable connection is required from the wind farm to shore. Both applications can avoid increasing grid congestion, while bringing the energy to off-takers. Physical constraints can be reduced if large capacity hydrogen pipelines are used instead of electricity cables.

- Another mitigation option is to invest in storage for green H_2. Inflexible industrial processes are dependent on a steady stream of energy. Green H_2 production based on intermittent RES sources, such as offshore wind, requires sufficient storage to smoothen supply.

The **project developer** is highly dependent on infrastructure to transport its produced electricity or green hydrogen to paying consumers. Project developers are highly dependent on central grid development by grid operators. They can only control the infrastructure risk if they are made responsible for infrastructure development, which reduces the number of interfaces they deal with externally. This mitigation option could, however, favour certain large actors, thereby creating an unfair advantage over other actors. Additionally, system planning might become more intricate.

The **demand side** is dependent on infrastructure for access to energy carriers. As a mitigation option flexible demand, e.g. an electrolyser or power-to-liquid (PtL) production facility, could be build close to the offshore wind farm to avoid the need for additional infrastructure. However, this would still imply a need for H_2 or PtL infrastructure. Building new industrial demand close to the coast would be a measure to reduce onshore grid expansion needs.

The **government** has a significant interest in mitigating the infrastructure challenge, as it is an essential building block for realising the offshore wind roll-out until 2040. To mitigate risks, the government could continue the Dutch centralized offshore wind development approach (mandating the TSO(s) to build the offshore infrastructure), it could support green H_2 production to reduce congestion, it could facilitate grid expansion measures by TSOs, it could provide regulatory guidance to ensure that location of demand is close to supply centres (e.g. with locational investment signals), or it could enable internationally coordinated grid planning. To limit opposition to grid deployment it could implement or improve early participation, transparency of processes, trustful communication, and public consultation and/or financial participation processes. Lastly, it could address supply chain issues (e.g. shortage of HVDC cables) through broader industrial policy.

3. Integration and interface challenge

The integration and interface challenge is highly relevant for all actors due to the many interfaces between them.

The **infrastructure companies** are central to enable integration across sectors and have many interfaces as they are required to connect all other market actors. The infrastructure companies are themselves highly reliant on the other market actors, as for example lower supply and demand volumes could lead to stranded assets. As a mitigation option, infrastructure companies could jointly or in a coordinated manner do the electricity and gas grid planning. Furthermore, they can stipulate requirements in the realisation and connection agreements that reduce integration and interface risks, and they can work on a European level (ENTSO-E, ENTSO-G) to facilitate cross-border system integration. To manage the risk of irregular electricity supply from the offshore wind farms, system services for grid stabilisation could be increased. This can be incentivised by TSOs through development of appropriate market mechanisms.

The **project developers** require a view on sufficient demand to make investments. Project developers have little influence on the future demand, but they could mitigate risks by coordinating electrification measures, e.g. stimulating electrification of residential heating within their client portfolio, with investments into new RES supply. They also require certainty that infrastructure will be available to transport the produced energy. Again, the project developer could integrate parts of the value chain within their scope as a mitigation.

Demand is reliant on the availability of electricity supply and transport infrastructure. Demand and supply are mutually reliant on each other. Integration risks could be mitigated by providing clarity early on regarding required demand volumes, flexibility characteristics of its demand, to ensure the infrastructure and energy products are fit for purpose. Another measure is to make demand patterns more flexible where this is possible, e.g. through industrial demand side management.

The **government** has numerous mitigation options available to handle the integration and interface challenge. It could for example mitigate risks by enabling a coordinated planning and a continuation of the centralized grid and offshore wind planning approach. This may include an integrated grid planning for electricity and gas. It could also analyse system needs across sectors and enable international coordination. It could also publish a roadmap on how to decarbonise current demand/supply as well as a clear vision for the level and nature of Dutch electricity demand over the next 20-30 years, including the anticipated degree of flexibility from transport, heat, industrial processes, hydrogen production and other sources. The purpose of this would be to provide a clear message on the Government's ambitions for areas that are uncertain and offer signals when further action is needed in future.

Assessment

From the above review of the affected actors and their risk mitigation capabilities **several conclusions can be drawn**. The project developer (i.e. the supply side) generally has various mitigation options available to mitigate the risks and challenges it is affected by. Both infrastructure and demand seem more limited in their mitigation options. This holds especially true for demand. The government has the greatest set of mitigation options.

However, any policy intervention requires careful deliberations. Addressing challenges on the level of individual market actors may work for some risks, however, this tends to create singular solutions. Value chain wide risks could benefit from a systems approach, which typically involves coordination and regulation by the government.

3. Current approach and drivers of success

In the most recent years, the offshore wind roll-out in the Netherlands has progressed successfully without support payments to the developers (i.e. the developers submitted zero-subsidy bids). That is an extraordinary achievement. The focus towards 2040 is create or maintain the necessary framework conditions for a continued zero-subsidy roll-out.

This chapter first describes the current approach on a high level and subsequently discusses what the drivers for success are currently and identifies those that are expected to be relevant in the further roll-out.

3.1 Current approach

The first offshore wind farms in the Netherlands were constructed under a governance model that placed most of responsibilities in the (pre-)development of offshore wind farms with the private developers[38]. Starting from the Borssele wind area, a new governance model was adopted where the Dutch government and electricity TSO were assigned more responsibilities. The new centralised governance model of the Netherlands is generally seen as a role model for other countries.

Under this current governance model in the Netherlands, the national government (with various bodies working closely together, including EZK, RVO, Ministry of Infrastructure and Water Management, Ministry of Foreign Affairs, and Rijkswaterstaat) is responsible for most of the steps in the pre-development, development, and planning process of offshore wind projects[39]. The pre-development phase starts with the designation of the search areas for future offshore wind farms, in accordance with the Water Act. Subsequently, a roadmap is established that stipulates which areas are to be realised by when and how they are connected to shore. Initial site boundaries are drawn and after that, site studies commence. RVO conducts investigations of the physical environment of the wind farm site, for both the soil, wind, and water conditions. This investigation provides extensive, high quality, data, such as geological, morphodynamical and geomorphological data, archaeological and unexploded ordnance analysis, metocean data, wind resource assessments, and geophysical and geotechnical data. This pre-development data is shared with interested developers to allow early access to pre-development information.

In parallel, an environmental impact assessment (in Dutch: *milieueffectrapportage*) is conducted, and further site design is carried out. This culminates in a site decision, which specifies various rights, obligations, requirements, and characteristics associated with the offshore wind site.

A tender is subsequently conducted which awards the winning bidder the following:

- Exclusive rights to construct and operate the wind turbines and their associated balance of plant[40] within the site boundaries
- Permits to construct and operate the wind farm
- Access to offshore electricity transmission infrastructure

[38] TenneT (2008), Jaarverslag 2008, **https://www.tennet.eu/fileadmin/user_upload/Company/Investor_Relations/Annual_Report/TenneT-AR08_nl.pdf**

[39] Rijksoverheid (2021), Rol van de Rijksoverheid bij wind op zee, **https://windopzee.nl/onderwerpen/participatie-educatie/rol-rijksoverheid/**

[40] The balance of plant in this model includes the foundation and inter-array cables.

- For tender procedures which include subsidy, grant (*beschikking*) of a support payment

This comprehensive package that is award to the winning bidder in a single round is often referred to as the “one-stop-shop” principle. Once the winning bidder is selected, the developer finalises contracting and financing of the wind farm to enable reaching financial investment decision.

3.2 Drivers for success

In light of the challenges identified in chapter 2, this section takes a closer look at the elements that contributed to the success of the current approach (i.e. the success factors) and seeks to identify those elements that should be maintained going forward. The assessment of what is a success factors and what not was based on discussions in the working group, expert interviews with selected members of the working group, representing the supply, demand and infrastructure stakeholders, and in-house experts from Guidehouse, supplemented with desk research.

In general, when analysing the Dutch offshore success, it is important to differentiate between the effects/indicators of success and the policy drivers behind those effects. We identify five key effects:

- Cost reduction: the costs of offshore wind farms has decreased from €125/MWh in 2013 to €72.7/MWh in 2016, to subsidy-free for the latest tenders.

- Stable capacity additions: thus far, ~2.5GW of offshore wind has been installed, with a stable pacing of both tender rounds and commissioning, with the expection of this trend continuing to at least the ~4.5GW offshore wind in 2023.

- Short development lead time: project times for the latest wind farms where around 4-5 years.

- Continuous interest by developers: in one of the latest tenders (Borssele I-II), seven developers placed a bid, and four successful tenders since.

- Minimising environmental impact: examples are piling noise reduction and the creation of artificial reefs within wind farms (in the Borssele III & IV wind farm).

The low and zero bids in the Dutch market can be attributed – next to favourable site conditions - to several **success factors** that keep the costs to developers down and mitigate and reduce their risks:

- Placing the responsibility for the pre-development with the government reduces lead times for project developers, and both direct costs (not part of tender) and indirect costs (reduced scope/complexity, reducing capital costs), while allowing environmental concerns to be dealt with in an early stage.

- The one-stop shop concept enables a limited workload during early stages of development, increases the certainty of bidders when submitting tenders and reduces the overall development time from the developer’s perspective.

- Having TenneT as the responsible party for the offshore electrical transmission assets reduces lead times for project developers, reduces both direct costs (not part of tender) and indirect costs (reduced scope/complexity, reducing capital costs), and allows for an integral solution with onshore electricity grid congestion in mind, all while considering environmental concerns.

- The stable regulatory regime reduces risks for developers (in turn reducing capital costs), minimalizes sunk costs and provides a clear tender schedule for developers to base investment decisions on. This predictable pipeline is particularly important for the supply chain.

- The allocation mechanism allows adaptivity to run procedures with or without subsidy, while also being flexible in the awarding criteria.

- The focus on de-risking meant that when developing the current policy together with the industry, one question was central to each decision: "which stakeholder is most capable of handling and/or mitigating risks for the considered activity in the offshore wind development process". De-risking lowers the barriers to market entry, reduces the doubling of costs (e.g. multiple parties conducting site studies for the same concession), reduces uncertainty developers face during bid preparation and reduces financing costs.

Based on our expectations of future challenges (see chapter 2), we identify **the following current drivers of success that could remain relevant for a future roll-out**:

1. Pre-development by the state: Like today, site characterisation will be required. This driver may be largely unaffected by future challenges. The goals of lowering barriers to entry, levelling the playing field, and minimising realisation timelines remain relevant.

2. One-stop-shop: This concept remains valid, however what will be included in the one-stop-shop package may be dissimilar. Our considerations on the tender product are included in chapter 7.

3. Stable regulatory regime & predictable pipeline: This driver is often touted as highly important by developers and suppliers. While greater adaptivity may be needed (e.g. to account for other types of infrastructure) regulatory stability and predictability should remain a priority.

4. Key changes for offshore wind up to 2040

This study focuses on the timeframe up to 2040. For 2040, we expect a largely decarbonized energy system with high RES shares and high demand for green hydrogen. Generally, we have a clearer sense of the expected changes until 2030 than for 2040. However, also for 2040 we can formulate expectations based on the developments that we are seeing.[41]

The high deployment figures for offshore wind will only materialise is demand grows proportionally. For **electricity demand**, we assume up to 2030 a growing direct electricity demand driven by electrification efforts in sync with RES capacity additions. The main demand sectors involved are the following:

- **Industrial & data centres electricity demand:** This sector has the largest potential for growth. The *Stuurgroep Extra Opgave* (based on the *Routekaart Elektrificatie* and the report from the Taskforce *Infrastructuur Klimaatakkoord Industrie*) estimates an additional demand by 2030 between 25 to 42 TWh/year from direct electrification & data centers. The study *Integrale Infrastructuurverkenning 2030-2050* (ii3050)[42], expects a growth of 32 to 74 TWh/year by 2050. Electric cracking may become a new source of additional industrial electricity demand, but it is too early to be conclusive.

- **Mobility**: This is another sector of expected significant demand growth. The number of electric vehicles is already growing quickly in the Netherlands and the pace is expected to remain high. The KEV2020 projects the 2030 electricity demand for mobility to be around 5 TWh/year, while the ii3050 scenarios project the 2050 demand to be in the order of 30 TWh/year.

- **Built environment**: Within this demand sector, the driver for growth is expected to electrification of heat demand (note: mobility is treated separately). The KEV2020 does not envisage electricity growth in the built environment up to 2030, while the ii3050 scenarios project the demand growth by 2050 to be in the order of 9-15 TWh/year.

- **Agriculture:** For this sector, the KEV2020 projects no significant electricity demand growth up to 2030, while the ii3050 scenarios project a further growth of approximately 11 TWh/year by 2050.

In summary, significant electricity demand growth is expected by 2030 by the *Stuurgroep Extra Opgave*, in the order of +20-40% from today. The KEV2020 expects another 5% growth from mobility but is conservative for the other demand sectors. Considering trends, such as applications of heat pumps and electric boilers, it seems that the KEV2020 underestimates the demand growth up to 2030. The ii3050 scenarios project a growth of roughly +100% to +150% by 2050. This excludes electricity demand for the production of green H_2.

The industry sector is expected to be the largest driver of electricity growth. This makes it an interesting target for a coordinated approach to incentivise demand and supply growth

[41] In this context, the recently adopted coalition treaty provides further insights into the level of ambition targeted. In any case, a 55% emission reduction for 2030 in the Climate Act is targeted, an increase to 60% reduction in emissions by 2030 is pursued. Source: **https://www.klimaatakkoord.nl/actueel/nieuws/2021/12/15/het-klimaatbeleid-in-het-coalitieakkoord**

[42] Netbeheer Nederland, Het Energiesysteem van de Toekomst Integrale Infrastructuurverkenning 2030 -2050 (2021), **https://www.netbeheernederland.nl/dossiers/toekomstscenarios-64**. This study explores supply and demand scenarios of a fully decarbonised energy system in 2050

jointly. To ensure such a coordinated approach, we propose a joint offshore wind – industry roadmap 2040 in section 5.5.

In addition to the direct electricity demand, we assume until 2030 a ramp-up of domestic green hydrogen consumption in line with the proposed 50% RFNBO target for industry, requiring large amounts of renewable electricity[43]. Once the electricity system is largely decarbonized – towards 2040 – the installed RES peak capacity needs to outpace the capacity of (direct electricity) demand. RES are inherently fluctuating. During especially windy or sunny times, electricity generation may be much larger than (direct) electricity demand. Conversion through electrolysis to green hydrogen will enable the use of these surpluses and prevent curtailment and redispatch. Conversely, hydrogen can be converted back to electricity in hydrogen-to-power plants to provide additional (green) electricity to the system in times of low wind speeds and low solar radiation, in addition to other flexibility solutions.

For **green hydrogen demand**, we expect up to 2030 a significant ramp-up in demand driven by the RFNBO targets. The green hydrogen market will start becoming larger. The State Secretary of the Ministry of Economic Affairs and Climate Policy estimated that if the Fit for 55 RFNBO targets would become binding, this may result in a green hydrogen demand of 14 – 31 TWh and that it would require 4 to 12 GW of electrolysis to supply this demand.[44] In the same letter to parliament, the State Secretary indicated this would require at least 6 GW of offshore wind to facilitate this hydrogen production, without detriment of decarbonisation of other electricity use. Up to 2040, we assume a liquid market with a large number of offtakers and an increased importance of imports and exports from/to neighbouring countries. This leads to higher competition, but also to higher demand.

Table 4-1 Targets and offshore wind production

	Offshore wind production	RFNBO target achievement
2030	21,5 GW[45] producing approximately 94 TWh[46] p.a. (e-demand 170 – 200 TWh)	14 – 31 TWh_{H2}, requiring at least 6 GW of offshore wind according to letter to parliament
2040	No targets defined. Range in System integration study by RVO of 31 – 38 GW[47], producing 135 to 170 TWh p.a.	No expected RFNBO target for 2040. In scenarios used in *Systeem integratie wind op zee 2030-2040*, industrial hydrogen demand ranges from scenarios 40 to 94 TWh_{H2} which translates to 57 – 134 TWh_e

With a view to the offshore grid, we assume that **most infrastructure up to 2030** is electrical. In the onshore electricity grid, bottlenecks and long development lead times could delay the addition of new capacity. In a letter to parliament, the State Secretary of the

[43] Note in this context that most likely a significant amount of hydrogen will be imported until 2030.

[44] **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof**

[45] Note, that this is not a set target yet and that 4 GW may only be realised after 2030 - by 2031. Source: **https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557**

[46] Assuming a capacity factor of 50%, which assumes high wind resource and usage of the latest wind turbine types.

[47] **https://offshorewind.rvo.nl/file/view/55041138/Rapport+-+Systeemintegratie+Wind+op+Zee+2030-2040+%28in+Dutch%29**

Ministry of Economic Affairs and Climate Policy estimated that based on current insights, it seems possible to land 6 GW in 2030 and to realise 4 GW by the end of 2031.[48] The letter further specifies that the development of offshore wind energy, its landing and the sustainability of the industry is a chain that must be viewed as a whole. In order to realise a significant increase in offshore wind energy by 2030, a precondition is that the realisation of these wind farms in terms of time and landing location ties in with the development of new demand for sustainable energy for the production of hydrogen and the electrification of industry. We assume that the onshore hydrogen grid up to 2030 will be well developed with the repurposing of gas infrastructure and the connection of current industrial clusters in a first onshore hydrogen grid. For the offshore hydrogen grid, we assume wind farm-overarching hydrogen infrastructure, which may up until 2030 however only connect first demonstrators of offshore electrolysis.

Up to 2040, we assume that the offshore electricity grid will become increasingly interconnected with potentially a meshed grid emerging (incl. e.g. the North Sea Wind Power Hub and the Danish energy islands). For the onshore electricity grid, we assume continued reinforcement to cope with additional electrification and growing RES capacities. We assume for the onshore hydrogen grid more interconnection with neighbouring countries, resulting in increasing import and export volumes. We also assume that significant transport capacity will be required between storage and demand locations, particular in case hydrogen is used as a flexibility source in the electricity system. For the offshore hydrogen grid, we assume wind farm-overarching hydrogen infrastructure, making use of scale advantages to reduce costs.

With a view to **electrolyser capacities**, we assume that the current national ambition of 3 to 4 GW by 2030 will need to be increased with a view to the requirements by the RFNBO quota. The State Secretary of the Ministry of Economic Affairs and Climate Policy estimated that if the Fit for 55 RFNBO targets would require 4 to 12 GW of electrolysis.[49] For 2040, no electrolyser capacity target exists. The capacity will depend on the development of hydrogen demand in the Netherlands, the scale of imports to the Netherlands, the demand for exports from hydrogen importing countries such as Germany, and growth of renewable electricity. In the study System integration offshore wind 2030 – 2040, Guidehouse and Berenschot investigated the integration challenges and solutions of 31 to 38.5 GW of installed offshore wind capacity in 2040[47]. The electrolyser capacity varied between 8 and 25 GW, depending on the scenario.

The expectations can be summarized in several trends. These trends have important implications on how policy measures should be designed for the future:

1. There will be a significant scale-up in offshore wind capacities towards 2030 that continues to 2040, which the offshore wind approach (incl. governance, allocation mechanism, site definition and support policies) must be able to manage.

2. A greater interplay between offshore wind roll-out, onshore grid development, onshore demand development and system integration can be expected and should be incentivized by policy.

3. From the offshore wind perspective, additional stakeholders, such as hydrogen producers, users, and industrial clusters, need to be considered in the allocation of sites.

[48] **https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557**

[49] **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof**

4. A fitting governance system is required for infrastructure, generation, and electrolysis developments.

5. There are new technical options available (see also sections 4.1to 4.3) and in development to combine offshore wind and hydrogen that need to be taken into account in all policy considerations.

6. There may be a move towards increasingly international offshore projects following the directions outlined by the European Commission in the context of hybrid and cross-border RES projects. Large offshore wind projects could be connected to various bidding zones and employ hybrid infrastructures (e.g. the Krieger's Flak Combined Grid Solution). This international dimension is also reflected in the Dutch involvement in North Seas Energy Cooperation.[50]

All these trends are considered carefully in Part 2 of this study. Before diving into the policy measures, one element to uncover in more depth beforehand is the trend number 5. New technology developments, most importantly hydrogen, enable new projects configurations that go beyond the currently implemented stand-alone offshore wind parks that are connected to shore electrically. Sections 4.1 to 4.3 provide more context on the different connection options available up to 2040.

4.1 Offshore wind connecting to shore electrically

In the past, and for the upcoming near-term future, the connection of offshore wind farm to shore via electrical transmission lines is most important. According to current insights and analyses, large-scale landing of wind energy other than in the form of electricity in the period up to and including 2030 is not possible.[51] For electrical connections a differentiation can be made between single, radial connections and concepts which combine transmission and interconnection.

Single, radial connections are the current primary connection type. The amount and locations of offshore wind that can be integrated electrically should be determined in keeping with demand growth projections and electricity grid congestion and reinforcements. Based on the study "Systeemintegratie wind op zee 2030-2040" it may be possible to integrate approximately 31 GW electrically by 2040, without major grid congestion issues, provided currently planned and investigated grid reinforcements are realised.[52] This is however highly dependent on the growth of demand and renewable electricity supply.

In the future, there may be a move towards more meshed, international concepts where multiple wind farms are connected to a single central offshore platform and where this single platform possibly in the future connects to multiple onshore or offshore substations possibly across multiple countries, such as the North Sea Wind Power Hub concept. Further considerations for large scale hubs are described in section 5.2.3. Note, such a concept may have impact on the appropriate market model (i.e. whether to implement offshore bidding zones or not), and assessment of market models is out-of-scope of this study.

[50] NSEC has among others, the goal to align tender schedules to reduce the strain on project developers and the attached supply chains. The actual feasibility of this goal is in practice often surpassed by political considerations.

[51] **https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557**

[52] **https://offshorewind.rvo.nl/blog/view/9d736052-eb25-4775-8c4d-062979d6efae/rapport-systeemintegratie-wind-op-zee-2030-2040-in-dutch**

4.2 Offshore wind combined with onshore electrolysis

The decarbonisation targets for 2030 and beyond require that all parts of the economy decarbonise. This requires large shares of renewable electricity. For some sectors and applications, such as the steel industry, this requires also the use of green hydrogen produced using renewable electricity. Without the right link between offshore wind and electrolysers, the green hydrogen will not get there in time or will be inefficient.

The combination of offshore wind and onshore electrolysis can take different forms. The onshore electrolysis could be connected to the electricity grid (on-grid) or connected directly only to an offshore wind farm (off-grid). The two models and their main advantages and disadvantages are described on a high level below.

On-grid configuration

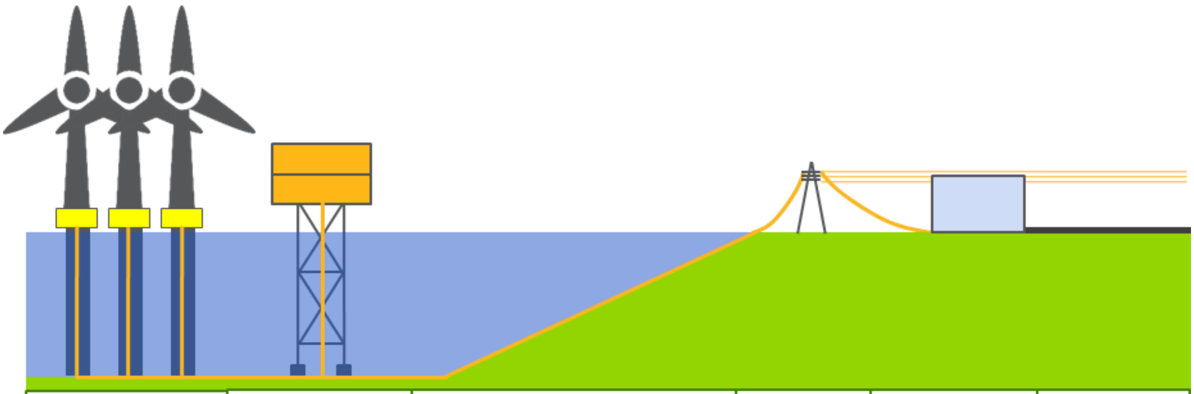

Figure 4-1 Configuration 1 – on-grid electrolysis

In this configuration, the high voltage assets are located on a centralised platform. Inter-array electricity cables connect the turbines to the platform. The platform is connected to shore with an electrical export cable. The electrolysers are located onshore, with a connection to the onshore grid.

Table 4-2 Advantages and disadvantages of configuration 1

Main advantages	Main disadvantages
• Enables full flexibility between supplying hydrogen or electricity. • Electrolyser onshore on-grid enables running the electrolyser based on other renewable electricity sources as well (if allowed by regulation). • Avoids the design challenges for wind turbines and electrolysers to operate in an off-grid operating mode	• Requires offshore HVDC transmission assets for the complete wind capacity, leading to higher spatial requirements, transport losses, and higher costs from a certain number of km.

Off-grid configuration

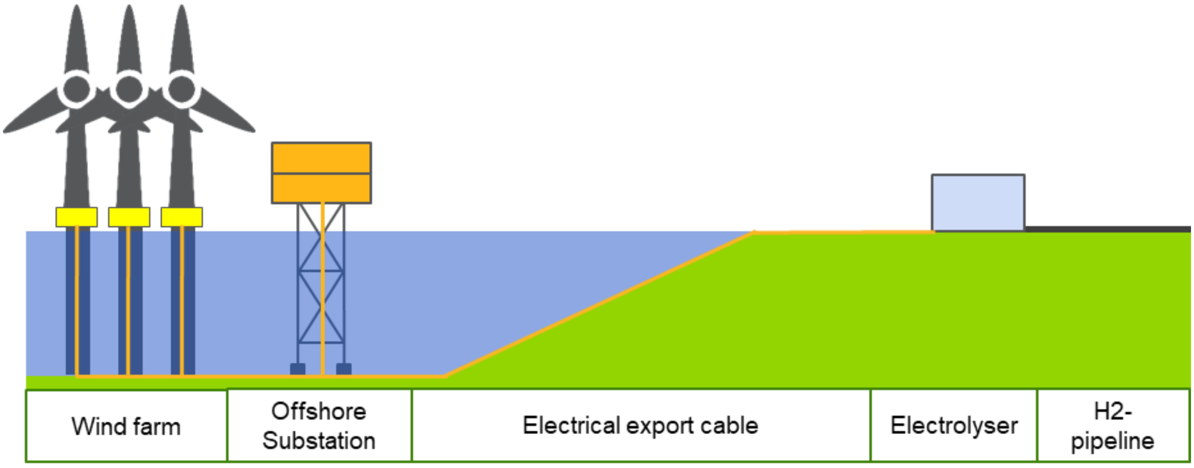

Figure 4-2 Configuration 2 – off-grid electrolysis

Here, the technical set-up for the wind farm, the offshore substation and the electrical export cable are the same as in configuration 1. The large difference in this configuration is that the electrical export cable is not connected to an onshore substation but directly to the onshore electrolyser.

Table 4-3 Advantages and disadvantages of configuration 2

Main advantages	Main disadvantages
• Technical maturity of both wind turbines and onshore electrolysers is high. • Realisation is not dependent on transmission capacity availability in the onshore electricity grid.	• Requires offshore HVDC transmission assets for the complete wind capacity. • Electrolyser cannot be operated flexibly, as it is dependent on the electricity production of the wind farm. • Lifespan of electrolyser does not align with the lifespan of the wind farm (i.e. project may not be future proof).

The question of whether the onshore electrolyser is on-grid or off-grid has important implications, which are shown in Table 4-4.

Table 4-4 Factors influenced by decision to build electrolyser on-grid or off-grid

	On-grid	Off-grid
Infrastructure ownership	Infrastructure realisation should follow the same governance as stand-alone offshore wind farms.	Without a connection to the onshore grid, there is no logical role for TenneT to realise the infrastructure, thus in this case it should be built by the project developer.

Incentives and economics	The offshore wind farm and electrolyser optimise against the market prices, hence produce H_2 in hours of low electricity prices and sell electricity in hours of high electricity prices.	The electrolyser is only fed by the offshore wind farm, thereby limiting the operating hours in turn negatively affecting the operating costs[53]
System value of electrolysis	Electrolyser may (under the right regulatory framework) be used as a flexibility source in the system; helping with grid constraints and enabling conversion of multiple renewable electricity sources.	Electrolyser would not negatively impact existing grid constraints but could also not be used for system flexibility. Furthermore, electrolysis would take place at times when electricity could be used directly.
Need for coordination (see section 5.3 on governance and section 6.2 on the allocation mechanism)	The deployment of both assets must be coordinated to reduce risk of stranded assets. Coordination between offshore wind and onshore electrolysis is especially relevant in the timeframe up to 2030. Up to 2030, the onshore hydrogen infrastructure is emerging, and hydrogen markets are not established and liquid yet.	Coordination is required as onshore electrolysis may be beneficial to avoid electricity grid congestion issues before 2030, by planning the location of offshore wind landfall and electrolysis as well as its timing. Furthermore, electrolysers will require large volumes of renewable electricity which the wind farm (and other renewables) can provide.

Based on the above analysis, we conclude that **on-grid electrolysers are more favourable than off-grid electrolysers**.

Next to the two models, there is a third option – a **hybrid model**. A hybrid model between off-grid and on-grid electrolysis may offer some of the advantages of both options. In such a model, a direct line between a wind farm and an electrolyser is realised, and the electrolyser connects to the grid with a connection capacity that is smaller than the electrolyser capacity. The capacity of the connection to the electricity grid can be based on the local electricity grid transmission capacity and congestion risks. The limitation in grid connection capacity may be reduced or lifted over time, as the onshore grid transmission capacity increases.

Some of the advantages of the hybrid model is that it would enable coordinated realisation of electrolysis and offshore wind in cases where the onshore electricity grid does not allow for fully on-grid developments. In contrast to off-grid, the hybrid model enables using some of the electricity produced by the wind farm directly by feeding it into the grid. It also enables providing the electrolyser with baseload electricity (reducing degradation of the stacks), and to operate the electrolyser in hours where there is an excess of renewable electricity while the connected wind farm produces less than the electrolyser capacity.

[53] See Figure 5 in **https://static.agora-energiewende.de/fileadmin/Projekte/2020/2020_11_EU_H2-Instruments/A-EW_223_H2-Instruments_WEB.pdf**

4.3 Offshore wind combined with offshore electrolysis

In the long term, hydrogen production at sea and therefore the landing of molecules is a real alternative to producing and landing offshore wind energy by means of electricity. Producing hydrogen at sea by means of wind turbines offers great advantages for the landing because a single pipeline can transport as much energy as approximately five connections with power cables.[54] This offers infrastructure cost advantages and a reduced spatial footprint.

The government is starting an exploration into this field and has submitted a proposal for the National Growth Fund for a first demonstration project of hydrogen at sea. With this demonstration project, the government wants to take a first step with hydrogen production at sea and learn how large-scale hydrogen production at sea can best be shaped. This project is several hundred megawatts in size and can possibly be realized before 2030. Large-scale deployment of hydrogen at sea on a gigawatt scale will however not take place until after 2030 at the earliest. In the exploration of landings for the period after 2030 (VAWOZ 2031-2040), the government will investigate the landing of wind energy by means of hydrogen.

We consider the following project configurations for joint offshore wind and offshore electrolysis developments. The models and their main advantages and disadvantages are described on a high level below.

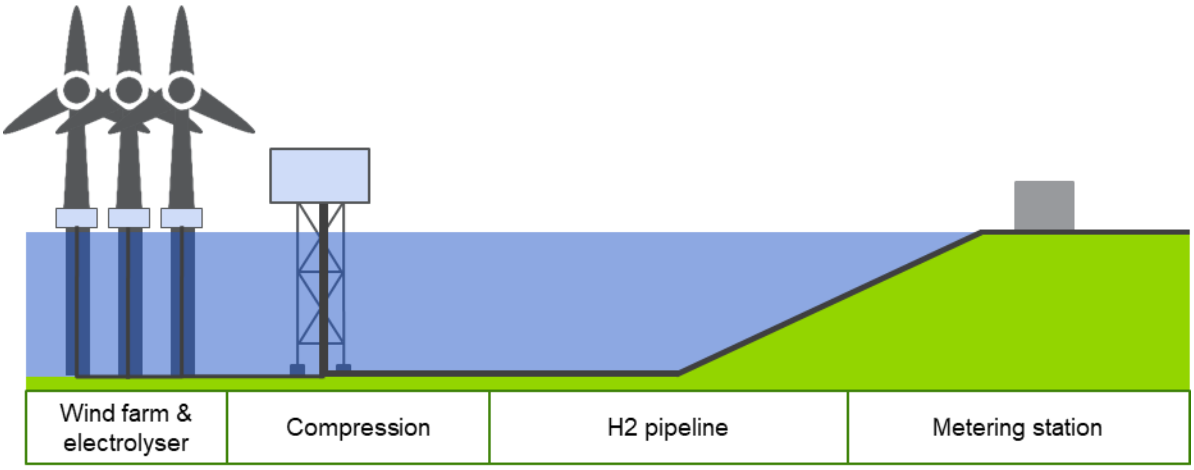

Figure 4-3 Configuration 3 - electrolysis integrated in wind turbines

In this configuration, the electrolysis takes place inside the wind turbines or at the foundation platforms. We refer to this as integrated electrolysis. Hydrogen pipelines connect the turbines to a compression platform, which itself is connected to a metering station onshore using a pipeline. The main advantages and disadvantages can be found in

[54] https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557

Table 4-5.

Table 4-5 Advantages and disadvantages of configuration 3

Main advantages	Main disadvantages
• Integration of electrolysis reduces infrastructure costs. No HVDC assets are required, nor large substructures (island, platforms) to host electrolysers are required. When realised at a large scale, a hydrogen pipeline is significantly cheaper than HVDC cables. • It enables removing some components in the wind turbine and electrolyser systems, as certain power conversion steps are not needed. This reduces CAPEX and losses. • By connecting a large capacity of offshore wind with a single pipeline, the environmental impact and spatial footprint of the transmission infrastructure is diminished • Realisation is not dependent on transmission capacity availability in the onshore electricity grid.	• Operation and maintenance of wind turbines with integrated electrolysers is much more complex/costly. • It is highly inefficient to supply electricity to the grid/consumers (via the reconversion of hydrogen to electricity). • Limited technical maturity: wind turbines with integrated electrolysers must operate in an island mode • Operating hours of the electrolyser are limited by the wind turbine.

Another option is configuration 4.

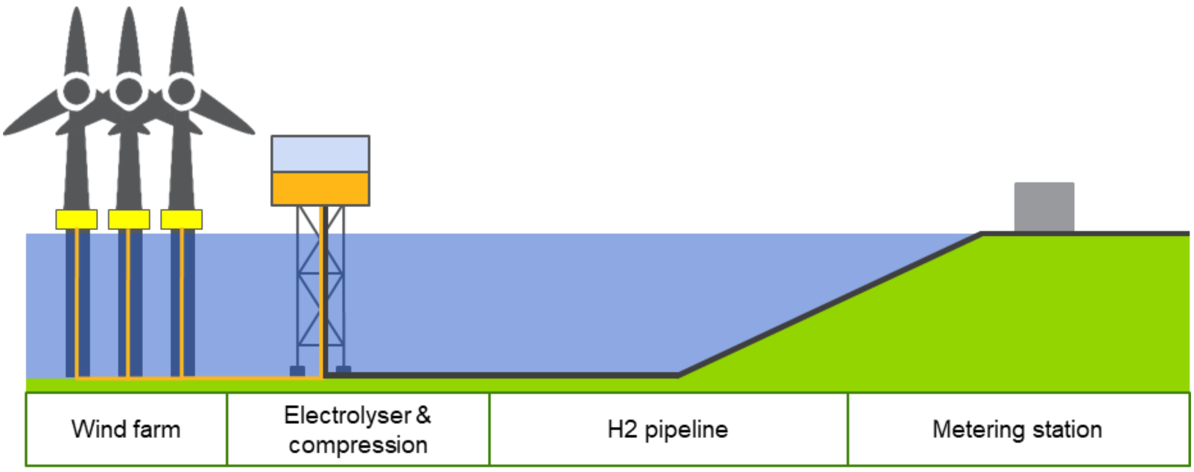

Figure 4-4 Configuration 4 – off-grid centralised electrolysis

In this configuration, the electrolysers are positioned on centralised platform(s) or on an island. Inter-array electricity cables connect the turbines to the platform(s)/island. The platform(s)/island are connected to a metering station onshore using a pipeline.

Table 4-6 Advantages and disadvantages of configuration 4

Main advantages	Main disadvantages
• Centralised electrolysis may reduce infrastructure costs, depending on the scale and location. No HVDC assets are required, however large substructures (island, platforms) are required to host electrolysers. It is expected that a large-scale electrolysis island will be substantially cheaper than using platforms. When realised at a large scale, a hydrogen pipeline is significantly cheaper than HVDC cables. • Technical maturity: wind turbines do not require redesign. • By connecting a large capacity of offshore wind with a single pipeline, the environmental impact and spatial footprint of the transmission infrastructure is diminished. • Realisation is not dependent on transmission capacity availability in the onshore electricity grid.	• It is highly inefficient to supply electricity to the grid/consumers (via the reconversion of hydrogen to electricity). • Infrastructure cost savings will only materialise when applied at a large scale. • Operating hours electrolysers are limited by the connected wind turbines.

Alternatively, configuration 5 could be considered.

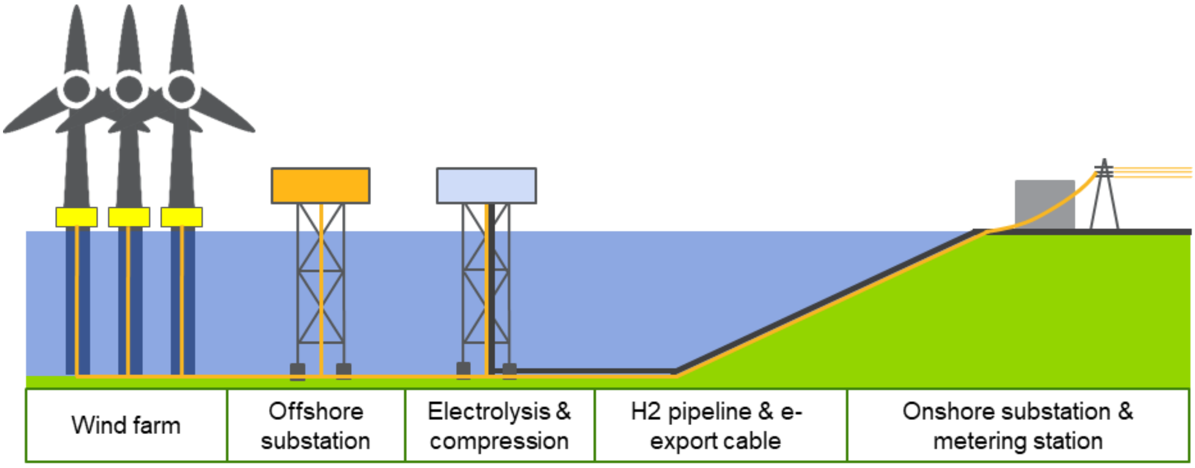

Figure 4-5 Configuration 5 – hybrid centralised electrolysis

In this configuration, the electrolysers are positioned on centralised platform(s) or on an island. The high voltage assets are also positioned on the centralised platform or the island. Inter-array electricity cables connect the turbines to the platform(s)/island. The platform(s)/island are connected to shore with a pipeline as well as an electrical export cable.

Table 4-7 Advantages and disadvantages of configuration 5

Main advantages	Main disadvantages
• Similar to the previous configuration, centralised electrolysis may reduce infrastructure costs, depending on the scale and location. • A hybrid electrical and hydrogen connection enables supplying both commodities and responding to movements and needs in the energy market (when oversizing on both parts). • It provides opportunities for electrical interconnection to other countries or other hubs/platforms in the Netherlands (creating a more meshed offshore grid). • Technical maturity: wind turbines do not require redesign.	• Infrastructure cost savings will only materialise when applied at a large scale. • Double infrastructure may result in a larger environmental and spatial impact.

Part 2: Policy options assessment

This second part of the study focuses on the assessment of options for policy measures. Four policy fields are analysed in detail here – governance, allocation mechanism, tender product & site definition, and support policy instruments. Each of these fields has important implications on the roll-out of offshore wind and thus needs to be assessed in the context of this study.

Overall, all four **policy fields are closely related** and have many interlinkages. All recommendations made in this part 2 are consistent with each other. The governance system is the foundation of all other considerations as it determines which actor does what. Many of the roles defined here are then reflected in the allocation mechanism and tender product. The allocation mechanism and tender product are also closely related – what is being defined in one chapter then gets allocated to bidders in the next. Here, also the connection with the support policy instruments emerges: if the subsidy-free roll-out fails, the allocation mechanism will have to not only allocate rights to construct, permits and access to infrastructure, but also support payments.

In terms of a **reading guide**, the following elements can be expected in the chapters:

- In sections 5.1 to 5.3 of **chapter 5**, we discuss for the offshore wind farm, the offshore infrastructure, and the electrolysers which actor is best placed to take on the roles and responsibilities. Section 5.4 combines these different considerations into an overall system – the masterplan. Lastly, section 5.5 continues these considerations for the broader value chain, also including the demand-side.

- **Chapter 6** discusses options within the allocation mechanism for the different connection configurations. For offshore wind only (electrically connected), we focus the discussion on a new, proposed continuous allocation mechanisms and different options therein with a view to the need for support, the inclusion of qualitative bids and the role of financial bids. For offshore wind and onshore electrolysis, we focus the discussion on the tender design and the form of support for the electrolyser. And lastly, for offshore wind and offshore electrolysis, we focus on the allocation process (tender or negotiated procedure) and award criteria.

- In **chapter 7**, we discuss three elements – the tender product, the site definition, and the realisation period and permit duration. In the tender product, we again differentiate between offshore wind, offshore wind and onshore electrolysis, and offshore wind and offshore electrolysis. The tender product sets out which items are granted to a successful bidder. For the site definition, we focus on the offshore scope, as the onshore scope is difficult to govern under a one-stop-shop principle.

- In **chapter 8**, we differentiate between the targeted best-case scenario of a continued subsidy-free roll-out and the backstop option of a support scheme in case the subsidy-free roll-out fails. For the best-case scenario, we discuss the role of PPAs and GOs. For the backstop, we discuss support scheme options for offshore wind and electrolysis.

In each of the chapters, we provide at the end a summary of all the recommendations made within the chapter. Based on the recommendations derived in these four chapters, part 3 includes a high-level check of the legal feasibility of the recommendations both for Dutch as well as EU legislation.

5. Governance

This chapter seeks to address the strategic, overarching questions around the alignment of future offshore wind roll-out, site definition, site allocation, infrastructure development and governance and the offshore wind value chain. The chapter consists of five sections. Section 5.1 discusses the current governance model for offshore wind farms, section 5.2 focuses on infrastructure governance, while section 5.3 discusses electrolyser governance. Section 5.4 introduces the idea of a masterplan that coordinates the site pre-development and definition with the infrastructure roll-out. Lastly, section 5.5 provides a wider view onto the entire offshore wind value chain, including the demand side.

The analysis regarding governance models focusses defining policy recommendations based on pros and cons of different options. In order to justify governmental intervention in the market under EU law, particularly in case state owned entities are assigned tasks, such justification requires further economic assessment to demonstrate market failure and to show the intervention is necessary and proportionate.

5.1 Offshore wind farm governance

The current approach to the offshore wind roll-out is described in section 3.1. It is a centralised approach with a key role for the national government and electricity TSO in planning, (pre-)developing and realising offshore wind farms.

The main alternative to this centralised approach to offshore wind farm realisation is a developer-led procedure, such as was applied in the Netherlands before the Borssele wind areas. In a developed-led procedure, developers lead the pre-development of sites during which they carry out site investigations, conduct an environmental impact assessment, and apply for a permit and an onshore grid connection. Although a developer-led procedure may enable developers more room to select the very best sites, and may allow for more technology flexibility, in our view it has several significant downsides compared to a centralised approach:

1. Limited ability to coordinate between different initiatives: under an open-door regime, multiple developers can request rights to develop a site in various search areas. Pacing the development, and ensuring certain areas are developed ahead of others (e.g. taking into account onshore grid reinforcements) is more difficult in such a regime. It could also make it more difficult to realise infrastructure that connects multiple wind farms.

2. Longer lead times: if a developer needs to conduct environmental impact and permitting work after having been awarded the rights to develop a site, the total lead time until realisation increases by several (2 to 3) years.

3. Sunk costs of development initiatives that fail to obtain a permit: developers may be unsuccessful in obtaining a permit, while having to spend significant amounts in carrying out site and desk studies as part of the environmental impact and permitting processes. These are sunk costs that do not provide value to society, that could be avoided in a centralised regime.

4. Higher development risk: as there is more uncertainty throughout the development phase whether permits and grid connection will be obtained, developers may need to account for this risk through higher contingencies and return rates. This increases the cost of successful developments, which in turn increases the cost of the produced electricity.

The current governance model realises a high degree of coordination and clarity. In chapter 3.2 we identified three drivers of success that are considered relevant for the further roll-out:

1. Pre-development by the state

2. The one-stop-shop principle

3. Stable regulatory regime & predictable pipeline

Pre-development by the state and the one-stop-shop principle require a centralised approach. In order to pre-develop a site, the government must determine many elements (e.g. location of site, design of site) and as a result of this, the decision-making process is led by the government. The pre-development is a prerequisite for the one-stop-shop. Here, the government centrally coordinates planning, infrastructure, permitting and support scheme. The governance model that realises these two drivers of success must therefore include a central role for the government, i.e. follow a centralised approach.

In our view, a centralised approach to developing the offshore wind farm sites is more suited than a developer-led approach considering the identified drivers of success and envisaged future challenges. Most steps in the current approach can be followed. We propose the consideration of following a rolling masterplan which results in a structured, predictable, and recurring decision-making process to assign search areas, infrastructure configurations and site definitions. It enables taking a comprehensive view of the energy system into the decision-making process. It is not a replacement for the offshore wind roadmap, but it is in essence an expansion of the offshore wind roadmap, as it starts earlier and has a broader scope. The masterplan is adaptive as it can respond to technology and demand developments into the decision-making process. We further explain this masterplan in section 5.4. The governance model for the offshore wind farm sites closely ties in with the governance model for offshore infrastructure, which is discussed in the next section.

5.2 Offshore infrastructure governance

In this section, we consider different governance models for future offshore infrastructure. The term governance models in this context means the division of roles and responsibilities of development and operation of the offshore infrastructure which connects wind farms to shore. Future governance models for offshore infrastructure need to consider the following expected developments:

1. The further roll-out of offshore wind towards 2030 and 2040 will result in feeding in large volumes of energy at the coast. In the selection of landfall locations for electricity and hydrogen, the point of connection to the onshore grid and transport capacity from the coast to demand centres and further inland needs to be considered. Therefore, the planning of the offshore wind farms and their offshore transmission assets needs to be closely **coordinated with onshore grid limitations** and planned reinforcements.

2. The complexity of integrating large volumes of intermittent renewables in the energy system increases as their share in the energy mix increases. Both balancing supply and demand, as well as avoiding structural grid congestions will become more complex and requires taking the need for **flexibility and system integration** into account.

3. Further **interconnection with other countries** is envisaged to contribute to security of supply and increasing social economic welfare. Realising interconnection by using offshore platforms and energy hubs could become a cost-effective alternative to

shore-to-shore interconnection. A more meshed offshore grid may also provide infrastructure cost savings (on- and offshore).

4. Offshore wind is poised to be one of the major contributors to meeting **decarbonisation targets** in the Netherlands. Delays or failure to realise projects due to delays in infrastructure realisation, may risk meeting targets.

5. Offshore wind may further become the largest energy source within the Netherlands, which could mean that in time the offshore infrastructure can be considered **critical infrastructure** from a security of supply perspective (in Dutch: *vitale infrastructuur*). Additionally, the infrastructure may in the future be considered an essential facility[55] under EU law, as duplication would be difficult due to geographical and economic constraints.

6. Hydrogen infrastructure and energy islands particularly benefit from **economies of scale**. Infrastructure that connects multiple wind farms is better positioned to capture this benefit.

The above developments, challenges and opportunities they pose and provide, call for coordination between offshore and onshore infrastructure, across wind farms and search areas, coordination across the value chain and across different energy carriers. Such coordination can be achieved through the realisation of infrastructure led by the government. This in turn requires the government to develop a governance model for offshore infrastructure. The governance model must anticipate the expected challenges through the entire value chain and support the Dutch public interests in the long term.

Current governance model

TSOs are regulated entities assigned by the government to carry out a limited set of tasks enshrined in law. This includes connecting producers and offtakers and transporting energy between them, operating the grids, investing in grid expansion and reinforcement, and for the national TSOs ensuring that the balance between supply and demand is maintained. Generally, the responsibilities of a TSO as well as ownership of the transmission assets can be assigned to different parties. Different unbundling models have been used in the EU[56,57], with Ownership Unbundling being the most common. The unbundling models are:

- Ownership Unbundling (OU): In this model, the network owner is also the system operator, and the TSO may not exercise control over supply and production activities. The network owner also fulfils the obligations as TSO.

- Independent Transmission Operator (ITO): In this model, a TSO may remain part of a vertically integrated undertaking (e.g. a company group which also includes energy generation). Detailed regulations exist to ensure separation of the ITO’s activities from the other activities of the vertically integrated undertaking.

[55] A facility or infrastructure which is necessary for reaching customers and/or enabling competitors to carry on their business. A facility is essential if its duplication is impossible or extremely difficult due to physical, geographical, legal or economic constraints. An example is a national electricity power grid. Denying access to an essential facility may be considered an abuse of a dominant position by the entity controlling it. Source: **https://op.europa.eu/nl/publication-detail/-/publication/100e1bc8-cee3-4f65-9b30-e232ec3064d6**

[56] **https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=EN**

[57] **https://www.ceer.eu/documents/104400/-/-/40770749-0a94-c65a-1b02-5c7a9ec3aa58**

- Independent System Operator (ISO): In this model, ownership and operation of the transmission grid is separated. The transmission owner is obliged to finance investments which are decided by the ISO.

The role of TSO for the onshore and offshore electricity transmission in the Netherlands is assigned to TenneT TSO B.V. (“TenneT”)[58] under a full ownership unbundling model. TenneT is 100% owned by the Dutch State. Under the current governance model for the offshore grid in the Netherlands, the national government (with various bodies working closely together, including the Ministry of Economic Affairs and Climate Policy, Netherlands Enterprise Agency, Ministry of Infrastructure and Water Management, Ministry of Internal Affairs, and Rijkswaterstaat) and TenneT collaborate closely to realise the offshore grid.

The role of TSO for the onshore (natural) gas transmission in the Netherlands is assigned to Gasunie Transport Services (which is a subsidiary of gas infrastructure company Gasunie)[59]. Offshore gas transmission assets in the Netherlands are owned and operated by private parties and the activity is subject to the Competition Law (in Dutch: *Mededingingswet*)[60]. Regulated third-party access is thus not provided, however the Gas Directive of 2009 stipulates Member States need to take measures to ensure third-party access is enabled[61]. Energiebeheer Nederland, with the Dutch state as its sole shareholder, participates in these assets in the form of a public-private partnership, with varying shareholding shares (typically around 40%)[62]. Gasunie has been further tasked to start development of an onshore hydrogen grid[63], which connects supply, demand and onshore salt caverns for hydrogen storage.

The governance of EU onshore gas transmission is highly comparable to that of electricity. It is a regulated activity, where TSOs are responsible for all phases of the development and operation of the assets. Some gas interconnectors are owned and operated by private companies, for example the BBL pipeline between the UK and the Netherlands is owned by a partnership of companies (including a subsidiary of Gasunie[64]) and operates as a non-regulated asset[65] (it was granted exemption from EU regulation) and publishes its own tariffs[66]. Regulation imposed on offshore gas transmission is further detailed in section 5.2.3.

Trends on a European level

Over the past years, various European governments have moved (or are considering a move) towards an approach in which the government and TSOs take a more prominent role in and take on a larger share of the offshore wind and offshore transmission infrastructure development risks and costs. The roles and responsibilities in the realisation of offshore wind are still shifting between governmental agencies, government-owned parties, and commercial entities in established markets. Generally, the **trend is toward more coordination by governments** and a greater role for TSOs.

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58 **https://www.tennet.eu/nl/ons-hoogspanningsnet/net-op-zee-projecten-nl/net-op-zee-nederland/**

59 **https://www.gasunietransportservices.nl/**

60 **https://wetten.overheid.nl/BWBR0011440/2022-01-01**

61 **https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ%3AL%3A2009%3A211%3A0094%3A0136%3ANL%3APDF**

62 **https://www.ebn.nl/over-ebn/**

63 **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof**

64 **https://www.bblcompany.com/about-bbl**

65 See section 5.2.3 for a further discussion of this term.

66 **https://www.bblcompany.com/tariffs/actualtariffs**

The approach applied in the Netherlands, Germany, France, and the centralised approach of Denmark (other Danish models are explained in the next paragraph) share similarities in that the TSO and other state bodies have most of the responsibilities for all parts of the development chain of offshore wind projects. The offshore transmission network review in the UK is investigating alternative models to the current Offshore Transmission Owner (OFTO) regime, emphasising a need for greater coordination between onshore and offshore grids, through Holistic Network Design[67]. Germany has shifted to a centralised model starting in 2021[68].

Denmark currently operates multiple governance models in parallel: for the Thor offshore wind farm in Denmark the developer is responsible for the transmission assets, in past tenders the Danish TSO Energinet had this responsibility. Denmark has additionally instated an open-door procedure (starting August 2021), where offshore wind farm developers can apply to develop projects at a location of their choice, instead of competing to build a project at a specific location and of a specific size. Through this procedure, private developers can apply to obtain permission to carry out feasibility studies in their selected area, and subsequently need to obtain permits from the Danish Energy Agency. However, the longer-term trend in Denmark is not necessarily toward a more developer-led model. Future Danish wind farms may be required to connect to energy islands, which will be realised through a public-private partnership. The Danish state will be the majority owner of the island itself (50.1%) and a private developer will be responsible to design the island within functional requirements set by the Danish state.[69] It is not yet decided whether the revenue model of the island owner will be regulated or not.[70] All electricity transmission infrastructure will be wholly owned by Energinet. The ownership model of storage or electrolysis/Power-to-X assets is not yet clear.

On an EU-level, developments regarding greater coordination, cross-border collaboration and the combination of offshore wind transmission and interconnection include:

1. The European Commission has proposed a revision to the Trans-European networks in energy (TEN-E) regulation (and the Council has formulated its provisional position), which concerns cross-border energy infrastructure. It highlights the need for more coordination with regards to national permitting procedures and a more integrated approach to grid planning, concerning the whole (international) offshore system. The European Commission proposed to implement regulation with provisions facilitating more integrated and international infrastructure planning and the implementation through a single point of contact.[71]

2. Countries in the North Sea region and Ireland signed the North Seas Energy Cooperation (NSEC) Declaration. This declaration aims to facilitate more cost-effective deployment of offshore renewables and emphasises the need for regional collaboration by governments[72].

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67 **https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1052212/otnr-webinar-presentation-jan-2022.pdf**

68 **https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2021/20210909_Offshore.html**

69 **https://ens.dk/sites/ens.dk/files/Energioer/tender-preparing_partial_agreement_of_1_september_2021.pdf**

70 **https://kefm.dk/Media/637661840231461613/Udbudsforberedende%20delaftale%20om%20langsigtede%20rammer%20-%20energi%C3%B8%20Nords%C3%B8.pdf**

71 **https://www.consilium.europa.eu/media/50423/st09732-en21.pdf**

72 **https://ec.europa.eu/info/news/north-seas-countries-ministerial-meeting-2021-dec-02_en**

3. Interest is increasing in the assets that combine transmission with interconnection, evidenced by initiatives and programs such as:

    - the Danish Energy islands[73]
    - the NL-GB Windconnector[74]
    - the two wind interconnector initiatives between DK-BE and DK-DE[75]
    - the North Sea Wind Power Hub initiative[76], and
    - the TenneT Wind Power Booster in Germany.[77]

Offshore wind is in our view poised to become a springboard for further international collaboration, interconnection, and market integration in the North Sea region.

The EC proposal for the revision of the Gas Directive and Gas Regulation shows that hydrogen networks will be regulated. The European Commission proposed that regulated third party access (TPA)[78] needs to be provided for hydrogen transmission[79]. However, until to the end of 2030 Member States may opt to apply negotiated third party access[80]. Furthermore, hydrogen transmission will be legally unbundled from natural gas transmission, with a separate asset base. For hydrogen networks that belong to vertically integrated undertakings (i.e. companies), Member States may designate independent hydrogen network operators in accordance with the rules on independent system operators for natural gas. Only until the end of 2030, Member States may designate an integrated hydrogen network operator unbundled in accordance with the rules on independent transmission operators for natural gas.

The EC proposal does not distinguish between an upstream pipeline network and transmission network for hydrogen, as it is done for natural gas. Furthermore, the scope of the directive includes onshore and offshore hydrogen networks. Concluding, it is expected that if the proposal is adopted as proposed, a hydrogen network operator for offshore hydrogen networks needs to be designated and the principles of negotiated and regulated third-party access as described above will apply.

Criteria to assess infrastructure governance model options

Given the upcoming changes and challenges, the current governance model for offshore infrastructure may need to be revisited. There are various governance models imaginable that distribute roles and responsibilities differently between market players. As identified before, we expect that offshore wind farms in the future will be connected to shore or an

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73 **https://en.energinet.dk/Green-Transition/Energy-Islands**

74 **https://www.tennet.eu/nl/tinyurl-storage/nieuws/windconnector-een-verbinding-tussen-de-nederlandse-en-britse-elektriciteitsmarkten-en-offshore-win/**

75 **https://www.nsenergybusiness.com/news/energinet-elia-50hertz-interconnector-projects/**

76 **https://northseawindpowerhub.eu/**

77 **https://www.tennet.eu/tinyurl-storage/detail/the-wind-power-booster-tennet-presents-6-gigawatt-hub-to-accelerate-offshore-expansion-targets/**

78 Under a regulated TPA regime, users are provided the right of access to transmission systems on the basis of published tariffs, which were previously reviewed and accepted by the national regulatory authority.

79 **https://ec.europa.eu/commission/presscorner/detail/en/IP_21_6682**

80 Under a negotiated TPA regime, infrastructure operators and users negotiate (bilaterally) the terms for access to the infrastructure based on dedicated regulatory requirements (e.g. non-discriminatory terms).

offshore grid through different infrastructure options – some wind farms may be connected radially electric, via hydrogen pipelines or a combination of both.

To assess offshore grid governance models in a transparent way, we have selected six assessment criteria. These are based on the most important challenges and public interests that have been formulated by EZK and RVO:

1. **Affordability of renewable energy:** The costs of offshore wind play a vital role in the affordability of renewable energy. Affordability should be considered on a system level, and a governance model should aim at minimising the cost over the entire value chain.
2. **Timely realisation**: The Netherlands is obliged to timely reach its greenhouse gas emission reduction targets. These targets have resulted is an ambitious offshore wind target for 2030, which is expected to increase, and further growth is expected by 2040. The Fit for 55 Package further proposes significant green hydrogen (and thus renewable electricity) targets by 2030. Furthermore, the cost of emission allowances under the European Union Emissions Trading Scheme is increasing, and the Dutch demand side sectors have a need for renewable electricity. Offshore wind is poised to be a major contributor to decarbonisation, and meeting the targets depends on the timely realisation of additional offshore wind capacity.
3. **Use of space and environmental impact:** The continued roll-out of offshore wind will require new connections to shore. Space offshore and at onshore landfall locations is constrained by different users, environmental considerations, and public acceptance. This increases the scrutiny on spatial planning decisions.
4. **Grid planning and coordination:** Offshore wind will create concentrated feed-in of energy at the coast. Structural congestion in the onshore electricity grid is a major concern currently and for the future roll-out. In addition, the use of offshore and onshore electrolysis requires consideration of the future onshore hydrogen grid. Thus, for both energy carriers, the planning of offshore transmission should be carried out with onshore constraints and opportunities in mind.
5. **Compatibility with future technologies and growing interconnection:** Wind turbine, transmission and energy conversion technology continues to develop. As the transition unfolds, a greater need for interconnection is foreseen, the role of green hydrogen in decarbonisation is poised to grow and meshed offshore grids can alleviate onshore electricity grid constraints. Future transmission assets should provide a basis to effectively integrate these developments.
6. **Experience and capacity of the actor:** Realising the pace of the further roll-out will be challenging for organisations. Experience and significant human capital will be required for adequate decision making and the maintaining the required speed of developments to meet the targets.

5.2.1 Offshore wind with electrical transmission

This section sets out the pros and cons for two options for the governance of offshore electricity transmission of offshore wind farms which span a broad range in the level of coordination: developer-led, where the developer of a wind farm is assigned the responsibility for the offshore grid connection, and TSO-led, where the TSO of the onshore electricity grid (in NL: TenneT) is assigned this responsibility. There are other possible governance models that are more of a hybrid between these two models (for instance, the UK OFTO model), which we consider of less relevance as they combine characteristics of the models assessed here.

Table 5-1 Assessment of governance models for offshore wind with electrical transmission

	Developer-led	Onshore TSO-led
Affordability of renewable energy	**Pros**: • Competitive pressure provides incentives to reduce cost of transmission assets • Integration of transmission assets in the wind farm design may unlock other optimisations possibilities (e.g. greater site density) **Cons**: • Sunk costs for pre-development of infrastructure for unsuccessful developers	**Pros**: • Enables standardisation which may lead to cost benefits • Developing multiple connections may enable stronger negotiating power toward the supply chain • Greater opportunity for (cost) synergies in development, construction and operation and maintenance • Overarching onshore – offshore responsibility may facilitate integration and reduce overall system cost • Generally, lower financing costs than private developers **Cons**: • Lack of competitive pressure to decrease cost (albeit some incentive through regulation) • Cost recovery through subsidies[81] or grid tariffs may reduce social acceptance, as it more directly links the cost of the transmission assets to consumers' electricity bill (compared to inclusion in wholesale electricity prices)

[81] For offshore connections of the current roll-out up to 2023, a subsidy budget of 4 billion is reserved, financed from the Opslag Duurzame Energie

Timely realisation	**Pros**: • Having multiple developers realising connections may reduce human resource bottlenecks, compared to if a single organisation develops all connections **Cons**: • Offshore and onshore connection development work will only start (in full) after selection of the successful bidder	**Pros**: • Offshore transmission development can commence before a wind farm is tendered, shortening realisation timeline of the wind farm and decreasing risks for wind farm developers • By planning the offshore and onshore grid in tandem, it may enable earlier insights into which onshore grid extensions are necessary • By frequently undertaking the permitting process, the TSO is accustomed to the process steps it needs to follow, deadlines it needs to adhere to and criteria it needs to fulfil **Cons**: • Pace of realising new offshore connections is constrained by the capacity of one organisation
Use of space and environmental impact	**Pros** • A developer may be able to undertake a more project-specific targeted social acceptance process **Cons** • Due to a project-specific initiative, a developer is unable to provide stakeholders a longer term perspective on all future developments in the region • A developer-led approach may result in less efficient use of the overall available sea-bed, in case search areas are divided in ways that limit the development of future wind farms The other **cons** are the inverted pros of a TSO-led model.	**Pros**: • Grid connection capacities that are larger than wind farm capacities can enable more efficient use of cable routes and landfalls[82] • Enables a coordinated planning strategy across individual wind developments through clustering of projects and combining social acceptance processes No **cons** identified

[82] Note, if the wind farm and connection capacity are equal (e.g. in case in the future the site capacity of HVDC connected site is increased to 2 GW), this pro is eliminated.

Grid planning and coordination	**Pros**: • A developer may be able to more cost effectively design a site when it is able to define the wind farm capacity freely **Cons**: • Before the tender is concluded, there may be uncertainty in location, timing, and capacity of required grid connections. Some degree of coordination would be possible through enforcing requirements to the successful bidder	**Pros**: • Full ability to coordinate the integration of renewables into the onshore grid due to extensive planning and pre-development phases • Upfront certainty regarding location, timing and capacity of required grid connections and required onshore reinforcements • Avoids running multiple permitting procedures in parallel for grid connection routes of competing developers No **cons** identified
Compatibility with future technologies and growing interconnection	**Pros**: • For individual connections, developers may have less technology lock-in, enabling quicker adaptation of innovation **Cons**: • Developers may have little incentive to make investments that enable further interconnection or a meshed grid, in case a concrete business case for this is not yet in place when the design is finalised	**Pros**: • Ability to standardise the transmission characteristics facilitates interconnection (interoperability of connections) • A TSO may be better placed to make anticipatory investments in hardware (e.g. switchgear, J-tubes) that enable build out of a more interconnected or meshed offshore grid • Further interconnection can benefit congestion alleviation and security of supply. The TSO can take these benefits into account (i.e. incentives beyond congestion rent) in the design of offshore grid assets **Cons**: • Taken to its extreme, standardisation may strain the supply chain (e.g. need for many HVDC sub-cables with the same characteristics)
Experience and capacity of the actor	**Pros**: • Division of workload over multiple organisations may result in a less constrained capacity (this relates to timely realisation as well) **Cons**: • The experience in the wind industry with offshore DC connections is limited. A tender criterion (pre-)selecting on this aspect would limit the playing field considerably.	**Pros**: • TenneT has gained significant experience in developing AC and DC (in Germany) offshore connections • A TSO can better anticipate future workload and invest in human resources, as it does not depend on winning concession rights **Cons**: • Assigning the workload to a single organisation requires it to grow considerably (particularly considering a potential increased 2030 target of 21.5 GW), while the workforce pool is limited

Based on the analysis, we consider the following tasks to be better placed with the onshore electricity TSO than market parties:

- **Coordination of onshore and offshore grid development:** While a framework of requirements could be imposed to steer developers in planning and designing offshore connections, full coordination between the onshore and offshore grids will be difficult to achieve. A TSO-led model will facilitate taking into consideration the landfall of wind in onshore grid investment plans. It furthermore creates the possibility for the integration of offshore wind further inland (e.g. routing HVDC cables to industry which is not situated at the coast). Under the right regulatory framework, TSOs could alleviate bottlenecks through planning electrolysers in strategic positions.

- **Realising interconnection by leveraging the offshore electricity grid:** An interconnector can be realised by private parties; a business case can be developed based on congestion rents that interconnectors can generate. However, further value of interconnection lies in increasing security of supply and alleviating grid congestion (delaying or avoiding grid reinforcements), private parties are not exposed to those incentives. A TSO would also be better positioned to coordinate with TSOs of interconnected countries.

- **Taking anticipatory investments, to enable a high roll-out pace and realise a system which is robust for future developments:** A private party will need to have a degree of certainty (i.e. rights to a wind farm site) before substantial investments can be made. A TSO can initiate development and fabrication work earlier, condensing the overall timeline to realise new wind farms, provided the regulatory framework enables sufficient de-risking. This aligns with the concept of a masterplan, that we explore in section 5.4. Furthermore, it may be a challenge to create the incentives that would result in private parties making anticipatory investments (e.g. additional hardware to enable future interconnection and preparations for a meshed grid).

Further based on the analysed advantages and disadvantages, we recommend for electrical offshore infrastructure to develop a governance model which places responsibilities for the planning, (pre)development, realisation and operation of the offshore electrical grid with the electricity TSO (working in close cooperation with the Ministry of Economic Affairs and Climate Policy, Dutch Enterprise Agency, the Ministry of Infrastructure and Water Management, and the future onshore hydrogen network operator). We recommend against a governance model which is focused on increase responsibilities to private developers.

The TSO can ensure timely realisation through early planning, through its mandate that enables starting before wind sites are assigned to a developer. Developers conversely depend on having success in competitive allocation processes, which limits pre-award development activities and may (comparatively) reduce their ability to invest in internal resources. We envisage that the need for central coordination increases as the share of renewables in the energy mix increases, which would speak to the long-term robustness of such a centralised model.

Break-out box: access for different users of the offshore electricity grid

In section 4.1, we envisage that the offshore electricity infrastructure will develop from single, radial connections to more meshed connections and interconnections. In such meshed systems, the offshore grid will include multiple producers and consumers as opposed to only point-to-point connections. A key question in this context is how to govern access to the offshore grid.

The proposal for the *Energiewet* includes provisions that stipulate access to the offshore (electricity) transmission grid for users other than offshore wind farms. In the *memorie van toelichting*, it is explained that the shared use of infrastructure may increase the use of the transmission assets, resulting in a more efficient use of the infrastructure. Some of the before-mentioned other users may include:

- Offshore electricity consumers, e.g. oil and gas production platforms. As an example, the offshore substation platform for the wind area Hollandse Kust (noord) will include provisions to connect other offshore offtakers.

- Onshore electricity consumers, e.g. large industrial electricity offtakers including electrolysis. While the *memorie of toelichting* does not directly mention these types of consumers, the proposal does not seem to preclude connecting onshore electricity consumers. This could enable a direct connection between an electrolyser and the offshore transmission grid.

The proposal for the *Energiewet* includes the right of electricity offtakers to request connection to the offshore transmission grid. The offshore electricity TSO may decline a request for access.

While the above-listed consumers are foreseen in the *Energiewet*, the proposal for does not include the right of other electricity producers (than permitted offshore wind farms) to request connection to the offshore transmission grid. This means that there is no transmission capacity provided for other offshore electricity producers such as floating solar PV plants, and wave / tidal generators. The *memorie of toelichting* explains that there are challenges in the allocation of capacity, considering the transmission capacity is based on the connected offshore wind farm(s) capacity.

Break-out box 1: access for different users of the offshore electricity grid[83,84]

5.2.2 Offshore wind and onshore electrolysis

As described in section 4.2, we make a distinction between on-grid and off-grid electrolysers when combining offshore wind and onshore electrolysis. This distinction is also relevant for the governance model.

- **On-grid:** In case of a combination of offshore wind and onshore on-grid electrolysis, the governance model for the offshore infrastructure can be identical to that of

[83] https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/publicaties/2021/11/26/wetsvoorstel-energiewet-uht/1.+Wetsvoorstel+Energiewet+versie+UHT+d.d.+17+nov+2021b.pdf

[84] https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/publicaties/2021/11/26/wetsvoorstel-energiewet-uht/2a.+MvT+Energiewet+%28algemeen+deel%29+versie+UHT+d.d.+17+nov+2021.pdf

electrically connected offshore wind (without electrolysis), i.e. a (electricity) TSO-led model of the offshore electrical infrastructure. Similar onshore – offshore electricity grid coordination is required, and similar arguments regarding future-proofing the offshore grid and accelerating realisation timelines apply.

- **Off-grid:** In case of a combination of offshore wind and onshore off-grid electrolysis, it is not sensible to make the onshore electricity TSO responsible for the offshore electricity infrastructure. As no electricity is fed into the onshore electricity grid, there is no coordination with the onshore grid required. Furthermore, as the electrical infrastructure only serves the electrolyser operator(s) as electricity offtakers, it would not make sense to, for instance, include the costs under the regulated asset base of the onshore grid. In case of a connection between a single producer and offtaker, the electricity connection could be considered a direct line, as defined in the proposal for the Energy Act (in Dutch: *Energiewet*)[85]. In such case, we would recommend assigning the responsibility of the offshore infrastructure to the wind farm developer, as the infrastructure would not form part of the offshore and onshore electricity grid. In case more of the infrastructure cost is attributed to the wind developer in an off-grid case, it may increase the levelised cost of hydrogen of off-grid electrolysis compared to on-grid. If due to public interests (including alleviating grid congestion), off-grid electrolysis is desirable, socialising cost of the electricity infrastructure could be considered.
  Finally, the proposal for the Energy Act also includes the possibility for a connection between the offshore electricity grid and an industrial installation. As the offshore electricity grid is connected to the onshore electricity grid by definition, this may be considered an on-grid or hybrid setup.

A hybrid model between off-grid and on-grid electrolysis, as further described in section 4.2, may offer some of the advantages of both options. In such a model, a direct line between a wind farm and an electrolyser is realised, and the electrolyser connects to the grid with a connection capacity that is smaller than the electrolyser capacity. We recommend to further investigate this hybrid between off-grid and on-grid onshore electrolysis, the possible associated governance models and legal implications.

5.2.3 Offshore wind with offshore electrolysis

Electrolysers can be situated offshore which changes the infrastructure required to transmit energy to shore. Depending on the configuration, the infrastructure includes a compression platform, a substructure where electrolysis is situated (a platform, or artificial island), an offshore hydrogen pipeline and an onshore hydrogen receiving or metering station. After transmission to shore, the hydrogen can be fed into an onshore hydrogen grid, once established. In case of a combined electrical and hydrogen connection, both transmission infrastructure types are combined.

As with offshore electricity transmission infrastructure, offshore hydrogen transmission will benefit from coordination of the planning and realisation of the infrastructure. Coordination is particularly relevant for the following aspects:

- **Affordability of offshore wind energy:** Hydrogen infrastructure benefits significantly from economies of scale. The cost of a pipeline does not scale linearly with increasing transport capacity, in other words, specific costs drop when larger capacities are realised reducing the cost of transport[86]. For both centralised and

[85] https://www.rijksoverheid.nl/documenten/publicaties/2021/11/26/wetsvoorstel-energiewet-uht
[86] https://offshorewind.rvo.nl/blog/view/9d736052-eb25-4775-8c4d-062979d6efae/rapport-systeemintegratie-wind-op-zee-2030-2040-in-dutch

integrated electrolysis, the transport cost can be reduced substantially by combining transmission of hydrogen from multiple offshore wind farms. Hydrogen infrastructure provides more flexibility in terms of transport capacity compared to electrical connections, over-dimensioning a pipeline is a relatively modest expense contrary to electrical cable over-dimensioning. In case of centralised electrolysis on an artificial island, the cost of an island also benefits from economies of scale. Coordination is required to enable realising infrastructure that is used for multiple wind farms.

- **Use of space and environmental impact**: A single pipeline can transport multiple times the energy that a HVDC cable can transport (e.g. the capacity of the existing NGT and NOGAT pipelines is in the order of 10-12 GW[87] (electric input equivalent), compared to 2 GW for a 525 kV HVDC cable). This advantage can be used to reduce the number of cable/pipeline corridors and landfalls, which in turn diminishes the spatial footprint and environmental impact along the cable/pipeline route. The spatial and environmental impact of realising a large-scale island, requires a separate consideration.

- **Grid planning and coordination**: As with the electricity grid, the offshore hydrogen infrastructure and onshore hydrogen grid need to be planned jointly. A large point in-feed of hydrogen could impact the transmission capacity of the connecting pipelines (in Dutch: *aansluitleidingen*). The onshore hydrogen grid still needs to be developed, thus a common planning between offshore electrolysis (and its locations of landfall) and the onshore hydrogen grid is advisable. In case of a hybrid electrical-hydrogen connection, the same grid planning and coordination requirements are relevant for the onshore electricity grid. Furthermore, a single pipeline could transport more than 10 GW of connected wind energy, which means that it is likely only a few pipelines are needed up to 2040. Such pipelines may then be considered critical infrastructure.

- **Timely realisation**: Coordination may enable hydrogen infrastructure developments to commence prior to the conclusion of offshore wind tenders. Particularly in case of assets such as artificial island, or new pipeline routes, lead times are substantial and may be the bottleneck. By starting infrastructure development early, it is possible to realise operational offshore electrolysis earlier.

Structure of the section

In this section, we examine different aspects relating to governance of offshore hydrogen infrastructure:

1. **Asset scope split**: In this sub-section we consider possible divisions of scope for integrated and centralised offshore electrolysis. Groupings of asset types are made that could be owned and operated by the same party.

2. **Governance of wind farm specific infrastructure**: In this section, we discuss governance for infrastructure that is specific to a single wind farm. This specific infrastructure connects a wind farm with shared infrastructure.

3. **Governance of shared hydrogen infrastructure**: In this section, we discuss governance for shared hydrogen infrastructure that connects multiple wind farms.

4. **Regulation of shared hydrogen infrastructure**: In this section, we examine the role of regulation to provide third-party access to shared infrastructure.

[87] Input from NGT and NOGAT

5. **Governance of a shared substructure and energy hub**: In this section, we discuss considerations for ownership and operation of a large-scale shared substructure for electrolysis, and additional considerations for an energy hub that includes both electricity and hydrogen.

1. Asset scope split of the offshore hydrogen infrastructure

In this section, we examine what would be a possible scope split (or grouping) of the assets between the wind farm and the onshore connection points. **We recommend that governance models are assigned on the basis of these groups of assets**, as the assets within a group serve a similar function and similar governance considerations apply.

To start, there are two main categories of offshore electrolysis:

1. **Integrated electrolysis:** Electrolysers are situated in or at individual offshore wind turbines

2. **Centralised electrolysis:** Electrolysers are situated on a centralised location offshore (artificial island or platform)

In the following figure, we visualise a simplified example of the infrastructure scope split for integrated electrolysis.

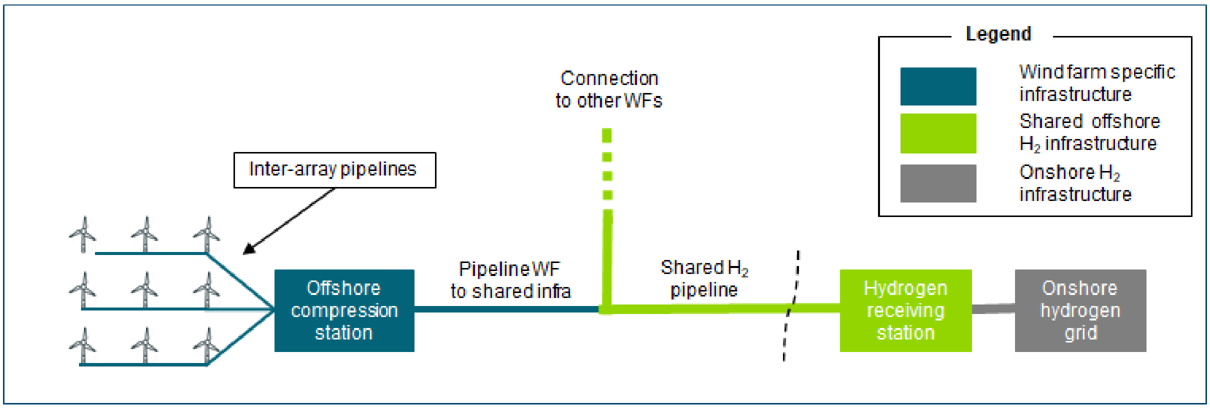

Figure 5-1: Example visualisation of the scope split for integrated offshore electrolysis

In this example, we consider three groups of assets:

1. Wind farm specific infrastructure: this consists of inter-array pipelines, an offshore compression station which is dedicated to a wind farm, and a pipeline that connects the compression station to a shared pipeline

2. Shared offshore H_2 infrastructure: this consists of a hydrogen pipeline that connects multiple wind farms to shore, and an onshore hydrogen receiving station

3. Onshore hydrogen grid: this consists of all onshore hydrogen transmission infrastructure

With this split, the infrastructure that is specific to a single wind farm is grouped together and separate from the shared offshore hydrogen infrastructure.

In the next figure, we visualise a simplified example of the infrastructure scope split for centralised electrolysis.

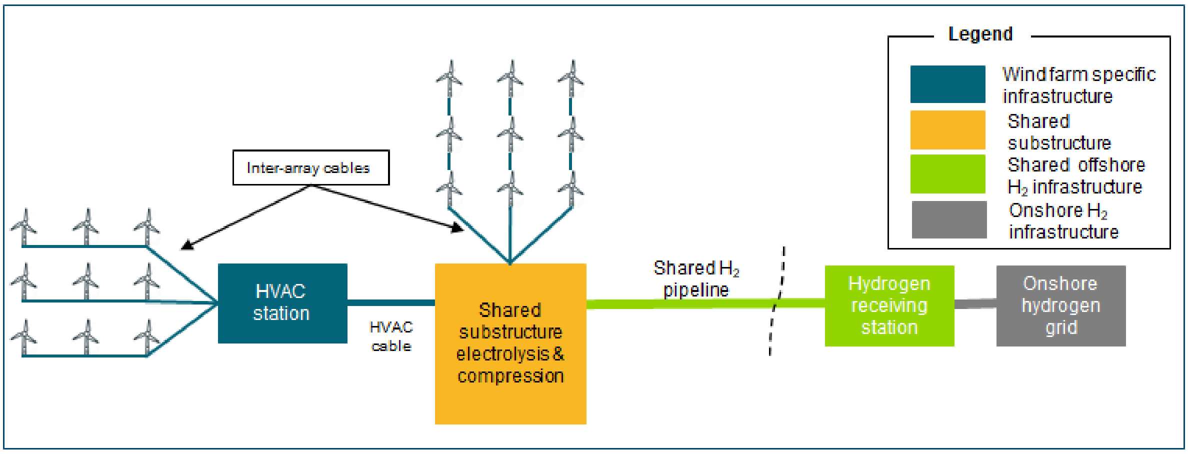

Figure 5-2: Example visualisation of the scope split for centralised offshore electrolysis

In this example, we consider four groups of assets:

1. Wind farm specific infrastructure: This consists of:
   a. inter-array cables;
   b. and in case needed due to large distances or other limitations, an offshore high voltage AC substation and a high voltage AC cable connecting to the shared substructure.
2. Shared substructure: This substructure can consist of a large platform or an artificial island. The substructure hosts electrolysers and its balance of plant (such as water and gas treatment, power electronics, maintenance facilities) and receives electricity from multiple wind farms.
3. Shared offshore H_2 infrastructure: This consists of a hydrogen pipeline that connects the shared substructure with an onshore hydrogen receiving station.
4. Onshore hydrogen grid: This consists of all onshore hydrogen transmission infrastructure.

With this split, the infrastructure that is specific to a single wind farm is combined, and the shared substructure may be split from the shared offshore hydrogen infrastructure. A reason for splitting these asset types is that different governance considerations may apply.

In the following paragraphs we discuss governance considerations for the wind farm specific infrastructure, shared offshore H_2 infrastructure and a shared substructure. Governance models for electrolysers are described in section 5.3.

2.Governance of wind farm specific infrastructure

For both centralised and integrated electrolysis, **we consider it appropriate that the wind farm developer is made responsible for realising the connection between the wind farm and the shared transmission infrastructure**, i.e. the wind farm specific infrastructure. The reasoning for it is that we do not consider the wind farm specific infrastructure to be part of the offshore transmission grid (be it hydrogen or electricity), and as such it does not warrant making the offshore electricity TSO or hydrogen network operator responsible to realise these assets. Making a third party (i.e. neither the wind farm developer nor

TSO/HNO) responsible would unnecessarily introduce an additional interface, and reduce the design optimisation possibilities for the wind farm developer.

In case of **integrated electrolysis,** the wind farm developer could be responsible for inter-array pipelines, a compression platform and a pipeline connecting to the shared hydrogen pipeline.

In case of **centralised electrolysis** this depends on the shared infrastructure:

- Wind farms connecting to a shared substructure (such as an energy island): in this case, the wind farm developer could be responsible for inter-array cables connecting to the substructure, and for wind farms with a greater distance to the shared substructure this could include an offshore HVAC substation and HVAC cable connecting to the substructure.

- Wind farms connecting to a shared hydrogen pipeline: in this case, there would not be a shared substructure, and a wind farm developer would need to realise its own platform for (centralised) electrolysis, based on the capacity of a single wind. In this case, the wind farm developer could be responsible for the inter-array cables, the substructure(s) containing electrolysis and compression equipment, and pipeline that connects to the shared hydrogen pipeline.

3. Governance of shared hydrogen infrastructure

For the shared offshore hydrogen infrastructure, we examine three governance approaches which we consider most relevant:

1. **Developer-led**: In a developer-led model, the developer of a wind farm realises the offshore hydrogen infrastructure to shore

2. **Onshore HNO-led**: In an HNO-led model, the onshore hydrogen network operator[88] would also be made responsible to realise and operate the offshore hydrogen infrastructure. This model could be considered analogous to the current governance model for the offshore electricity grid, where the onshore e-TSO is also made responsible for the offshore electricity grid.

3. **PPP-led**: A public-private partnership consists of a consortium where private parties and a party which represents the public interests work together. The latter could take on the form of a state-owned company, such as Energiebeheer NL, Gasunie, or a specific vehicle.

[88] In the proposal for a revision of the Gas Directive and Regulation, the EC defines the hydrogen network operator as a party that is tasked with realising and operating hydrogen transmission infrastructure.

Table 5-2 sets out the general pros and cons for the different governance models, after which the question of regulation is discussed.

Table 5-2 Overview of pros and cons for offshore hydrogen infrastructure governance

	Pros	Cons
Developer-led	• No interfaces between production and offshore transport • Access to private sector expertise • Does not require public funds	• Lacks direct incentive for coordination on/offshore • Challenging to realise infrastructure at a scale beyond a single wind farm • May pose barriers to third party access • May be difficult to meet expected unbundling requirements stemming from the recast Gas Directive
Onshore HNO-led	• Ability to directly coordinate on/offshore infrastructure • Ability to make anticipatory investments to realise scale beyond single wind farm • Offers tariff transparency, if regulated • May enable a shorter overall timeline, through early investments	• Limited access to private sector expertise (albeit the Dutch gas TSO also has experience offshore)
PPP-led	• Access to private sector expertise • Reduces public funds required • Offers tariff transparency, if regulated • May facilitate re-use of existing infrastructure	• May pose barriers to make anticipatory investments • May limit ability to coordinate on/offshore infrastructure

Overall, **we consider an onshore HNO-led or PPP-led model with a strong representation of public interests more fitting** than a (wind farm) developer-led offshore hydrogen infrastructure model. The main reasons against a developer-led model are the expected challenges to realise infrastructure at a scale beyond a single wind farm, possibly barriers to providing non-discriminatory third-party access, and challenges to meet the expected unbundling requirements stemming from the recast of the Gas Directive.

Re-using existing offshore gas pipelines

Another element to consider is the opportunity to re-use existing offshore gas pipelines. The study System Integration Offshore Wind 2030-2040 highlighted that for search areas 6 and 7, there is an opportunity to re-use nearby existing gas pipelines, which would reduce costs, reduce the number of landfalls and pipeline/cable routes through potentially sensitive areas. It could also accelerate the realisation of offshore electrolysis, as long lead times for permits for new routes are avoided.

Operators of the NGT and NOGAT pipelines are investigating how re-use can work in practice, considering that connected gas production platforms are expected to keep producing gas for some time to come. It may be the case that gas production platforms do not ramp down to zero prior to the connection of hydrogen producers. Operators are considering different solutions, such as re-routing of gas production platforms to realise pure hydrogen transport, separation and conversion of hydrogen and natural gas, and co-blending of hydrogen and natural gas. We have not evaluated the solutions considered by pipeline operators, and further investigation of the options is recommended.

The operators confirm that the pipelines are regularly inspected (internally and externally) and are in good condition. They are conducting a certification process to extend the lifetime of pipelines and to certify the pipelines for the transport of hydrogen. The transport capacity (expressed in GW of wind farm electrical output) for NGT is expected to be 10 to 14 GW and for NOGAT to be 10 to 12 GW.

The operators envisage close collaboration between different pipeline owners and operators, to realise an offshore hydrogen pipeline network that spans beyond the Dutch borders.

Conclusion regarding ownership and operation of shared hydrogen infrastructure

Considering the benefits of realising a shared infrastructure, and the importance of such infrastructure in the future energy system, we argue that strong representation of public interests is desired, which speaks in favour of the onshore HNO or PPP. An onshore HNO-led model may offer better coordination between on- and offshore infrastructure and between the realisation of hydrogen and electricity infrastructure, while a PPP may offer better access to offshore gas industry experience and could facilitate re-using current infrastructure in case a PPP includes current pipeline owners. In order to provide clarity and a level playing field we recommend that tariffs and contractual and technical conditions are published ahead of the opening of an offshore wind tender. Due to the absence of competition, transparency in tariff formation is desirable, which is further discussed in the next section.

As this study focussed on offshore wind, the working group did not include all actors that are relevant for decisions on governance models for offshore hydrogen infrastructure. We recommend to additionally engage with the actors in the on- and offshore gas industry to uncover the lessons learnt in the Dutch gas industry and to further test the investigated models.

4. Regulation of shared offshore hydrogen infrastructure

The proposal by the European Commission for the recast of the Gas Directive and Regulation provides some guidance on the direction of hydrogen transmission regulation at EU level. In the proposal, HNOs are defined as parties that are tasked with realising and operating hydrogen transmission infrastructure, and its activities should be separated from energy production. The proposal equates onshore and offshore hydrogen networks and does not make a distinction for upstream hydrogen networks (as is done for natural gas).

The question when a hydrogen pipeline constitutes a network or when it is a direct line merits further legal assessment. However, in case of connecting multiple wind farms to shore it seems likely this would be deemed a hydrogen network. In this case, the proposal defines which regulation should be applied, and as a minimum negotiated third-party access needs to be provided.

Realising non-discriminatory third-party access for wind farm operators to shared offshore hydrogen infrastructure is key to provide clarity and reduce risks during the development and operational phases of wind farms that include offshore electrolysis. There are two main options for TPA: regulated TPA and negotiated TPA. Under regulated TPA, users pay regulatory set tariffs for the services, while under a negotiated TPA the tariffs are bilaterally negotiated but access conditions are supervised by regulators. The most suitable procedure is closely linked to the degree of competition, in case of market concentration there may not be sufficient downward pressure on tariffs, and regulation of tariffs may provide a better outcome. To stimulate investments, under certain conditions, exemptions to TPA regulation can be provided to operators. Regulation is used to prevent abuse of market power and discrimination against users of assets.

The proposal for the recast of the Gas Directive and Regulation states that Member States may implement negotiated third-party access or regulated third-party access up to the end of 2030 and **requires Member States to implement regulated third-party access after 2030**.

This proposal provides clear direction. However, several elements here are noteworthy:

- The proposal is currently being negotiated and may change.

- The proposal introduces a transitional period in which either option may be implemented. Here, the government must be able to argue why a certain TPA model was chosen.

- In the natural gas industry, exemptions to the Gas Directive have been granted in practice, and exemptions may not be completely ruled out for hydrogen transmission.

As a result of these considerations, we analyse here in more detail the advantages and disadvantages of the two models by examining offshore upstream pipeline networks (in Dutch: *gasproductienet*) and drawing a comparison with offshore wind.

Comparison with upstream pipeline networks

As an asset type, upstream pipeline networks in the offshore natural gas industry are a close analogy. Therefore, it is of interest to evaluate what degree of regulation has been applied in some case examples. The current Gas Directive only prescribes that Member States must take measures to ensure that third parties are able to obtain access to upstream pipeline networks.[89] Multiple models are used across Europe, for example:

- In the Netherlands, for several pipelines a PPP is used (with Energiebeheer Nederland having a stake in all offshore pipelines) and the activity falls under competition law (*Mededingingswet*)[90]. For these pipelines, a single, distance dependent tariff is used for all connected parties and standardised contract terms are

[89] **https://north-sea-energy.eu/static/1f13bd895cfa3e630af1bb277f2630f2/11.-FINAL-NSE3_D2.2-D2.3-Analysis-of-legal-basis-for-offshore-hydrogen-planning-and-Legal-assessment.pdf**
[90] **https://wetten.overheid.nl/BWBR0011440/2022-01-01**

used. The tariffs apply to capacity reservations by the connected parties, i.e. not the actual volume transported. Tariffs are currently not published.

- In Norway, a PPP owns the upstream pipeline networks (Gassled, which includes state company Petoro AS to represent public interests), its operation is conducted by a state-owned company (Gassco), and access is granted through regulated TPA[91].

- In Denmark, gas pipelines are owned and operated by two parties: Danish Offshore Gas Systems (a subsidiary of Ørsted) and the Danish Underground Consortium (a PPP including Nordsøfonden). Different regimes apply:

  - Danish Offshore Gas Systems A/S: Operates the offshore pipelines to the Nybro processing plant. While there has been an intention for several years to sell these assets to Energinet, the transaction has yet to happen[92]. It is a regulated third-party access regime and tariffs are transparent and published[93].

  - Danish Underground Consortium: Operates the Tyra – F3 pipeline, which is not regulated[94,95].

Multiple models are used in Europe to ensure TPA to upstream pipeline networks and have been effective in realising third-party access. There are some differences between offshore gas pipelines and hydrogen pipelines, which imply other considerations should be taken into account when selecting the governance model.

Comparison to offshore wind

The equivalent infrastructure in offshore natural gas (i.e. upstream gas pipeline network) shows multiple models for this market are used in Europe (e.g. in Norway it is regulated, in the Netherlands it is not) and can be effective. However, there are some noteworthy differences between offshore natural gas and offshore wind (with hydrogen transmission).

- The competition between offshore gas producers in the Netherlands is less direct than between offshore wind developers, which (under the current governance model) participate in a competitive tender for the same site.

- Another difference stems from the process that wind developers follow from development to realisation of a wind farm. Wind developers at time of a bid, need to understand if and what level of fees need to be paid to access the hydrogen infrastructure. Without clarity, they might need to include a contingency, which is detrimental to the competitiveness of a bid. Some wind developers may already have realised a connection agreement with hydrogen infrastructure for an earlier concession (i.e. they have information regarding the costs for access). Furthermore, if a public-private partnership is used for the offshore hydrogen infrastructure and if it includes wind developers, incentives may exist to discriminate in favour of the developer that participates in the PPP. This can be considered an argument in favour

91 **https://www.regjeringen.no/globalassets/upload/kilde/oed/prm/2002/0157/ddd/pdfv/167789-fakta_transportsystemere02.pdf**

92 **https://energywatch.eu/EnergyNews/Oil___Gas/article10748445.ece**

93 **https://gastransport.orsted.dk/capacity-products**

94 **https://eng.nordsoefonden.dk/activities/gas-pipeline/**

95 Interviews with pipeline operators

of published tariffs: all wind developers bidding for a concession have the same information and are offered the same conditions, i.e. creating a level playing field.

- Finally, it is expected that offshore hydrogen pipelines will be designed to minimise the amount of landfall locations needed to bring the energy to shore. This would result in very little competition between different providers of offshore hydrogen infrastructure; thus, it is desirable to have sufficient insight to evaluate whether the tariffs set are reasonable and justifiable.

Conclusions regarding third-party access

Based on the above comparisons, the following reasons might favour the option of regulated TPA to provide access to offshore hydrogen infrastructure over more market-based procedures:

1. In order to promote a level playing field between offshore wind farm developers;
2. To avoid information disbalance between offshore wind farm developers;
3. To mitigate the risk of discriminatory access incentives; and
4. To mitigate the risk of abuse of market power as there will be limited to no competition between hydrogen infrastructure providers; and
5. To avoid monopoly profits.

Finally, the direction that is put forward by the proposal of the EC for a **recast of the Gas Directive points clearly towards regulated third-party access of hydrogen networks** for the long-term. Under the proposal there is also a transitional period until 2030 under which a negotiated TPA could be implemented. One point of uncertainty from the proposal is whether the shared offshore hydrogen infrastructure can be considered a network or not. This requires further attention during the negotiations.

5. Governance of a shared substructure or energy island

Large scale shared substructures or energy islands could be considered a separate type of asset, with its own governance considerations. While this has not been a central research topic and discussion topic, we share our initial considerations in this sub-section.

The following **characteristics** are particular for a shared substructure or energy island:

- A shared substructure or island may have various functions, that go beyond transmission of hydrogen. For instance, areas can be leased to electrolyser operators, miscellaneous services for wind farm operation and maintenance can be provided (e.g. vessel harbour, staff accommodations), there could be a combination of electricity and hydrogen transmission assets. As such, the substructure itself may not fit under regulated asset bases for hydrogen or electricity transmission.

- The national government has expressed specific interest in playing a directive role when it comes to the realisation of artificial islands in the Exclusive Economic Zone. In the *Ontwerp Programma Noordzee* it is argued that the national government should be the sole party that initiates the development of an artificial island, due to its responsibility to assure safety (territorial, physical and economic), ecological protection, political stability and compliance with international law[96].

- An artificial island may have a substantially longer lifetime than that of offshore wind farms connecting to the island. The national government intends to retain control over the activities that take place on the island throughout its lifetime and may desire to assign a different purpose to the island during its lifetime.

Due to the above, a **different governance model than the model for shared hydrogen infrastructure** may be needed depending on the nature and scope of the shared substructure or energy island.

In case of an energy island that serves as a **substructure for electrolysis and hydrogen transmission assets**, involvement of the offshore hydrogen network operator is desirable, to ensure the design of the island enables effective realisation and operation of the hydrogen transmission assets. However, it can be argued that multiple parties may be involved in operation of the energy island, as the energy island would serve additional functions beyond hydrogen transmission (i.e. electrolysis).

In case of an energy island that serves as a **substructure for electricity and hydrogen transmission assets**, it may be argued that involvement of the electricity TSO and offshore hydrogen network operator in a joint venture could facilitate alignment between the different scope items. Involvement of the TSO and HNO may ensure that the island has the right characteristics to allow for effective realisation and operations of the transmission assets.

For both types of energy island described above, there is an **option to involve the private sector** in the realisation through a public-private partnership (PPP). The Danish Energy island in the North Sea is developed in accordance with such a model[97]. Advantages of including the private sector in infrastructure development could entail a higher degree of innovation, reduced need for public funds, efficiency, and improved risk management[98]. Disadvantage may include higher financing and transaction costs, complex structuring and inflexibility.

In case of combined electricity and hydrogen transmission, the **rights to use the electrical connection warrants a separate investigation**. In this case, multiple wind farms would compete for access to the (likely limited and often congested) electrical transmission capacity. Clear capacity allocation rules are necessary to deal with these situations. A fitting market design must be applied to maximise societal value of the dual transmission connection.

In case an **energy island is realised with interconnection** to other countries or electricity market bidding zones, there are additional considerations to take into account:

- When combining transmission of electricity from offshore wind with interconnection, EU Electricity Market Directive and Regulation poses challenges, as there is a minimum interconnection capacity requirement that states that 70% of the interconnector capacity needs to be made available to the market. When this

[96] https://open.overheid.nl/repository/ronl-b28d8bb1-3b31-4f83-8cf8-bbeddf862186/1/pdf/4-ontwerp-programma-noordzee-2022-2027.pdf

[97] https://www.offshorewind.biz/2021/09/03/danish-parliament-decides-on-energy-island-specifics-state-to-own-50-1-pct/

[98] https://www.dlapiper.com/en/europe/insights/publications/2021/03/public-private-partnerships-for-infrastructure-investment/

requirement is applied to an energy island, this means that part of the electrical transmission capacity needs to be kept available for interconnection[99].

- An approach currently considered to resolve the challenge, is the creation of an offshore bidding zone that encompasses the energy island. This results in the energy island having its own bidding zone, and all connections to shore are considered interconnections, and the 70% rule no longer constraints the transmission of offshore wind electricity to shore. The application of an offshore bidding zone has numerous impacts on the business case of connected offshore wind farms, as the revenue distribution between wind operator and interconnector operator changes[99]. The application of an offshore bidding zone is expected to result in a lower electricity price than in case of a radial connected wind farm. These impacts, and the need for mitigating instruments requires further assessment.

Concluding, as with shared hydrogen infrastructure, representation of public interests is a key characteristic the governance model for a shared substructure or energy island should provide. For assets that combine electricity and hydrogen transmission, involving both offshore electricity TSO and HNO may be appropriate. Involvement of the private sector through a PPP may be considered, which could stimulate innovation and reduce the need of public funds. The national government is envisaged to be the sole initiator of an artificial island. In case interconnection with other countries is realised, the impact on the business case of wind operators requires further consideration.

5.3 Electrolyser governance

Electrolysis installations are envisaged to be realised and operated by private parties, although in a letter to parliament the state secretary of the Ministry of Economic Affairs and Climate Policy recognised that in case private parties do not develop electrolysis capacity sufficiently quick, a role of the network companies could be explored[100]. In the remainder of the chapter, we assume that electrolysis is developed and owned by private parties.

Onshore electrolysers

Depending on the use of joint (or integrated) tenders with offshore wind, onshore electrolysis may be owned by a consortium which includes a wind farm developer. The key question for onshore electrolyser governance is the degree to which the government can play a role in the development stage.

Before the financial investment decision for an onshore electrolyser is taken, several development steps need to be concluded:

- Identification of suitable locations, ideally with vicinity to the land fall locations of offshore wind, the high voltage grid (considering congestion) and the future hydrogen grid (and in the near term, possibly vicinity to hydrogen offtakers)

- Basic design/engineering of the electrolyser facility, to assess the footprint required, and start the environmental impact assessment

- Conducting onshore site surveys

[99] **https://www.tandfonline.com/doi/full/10.1080/02646811.2021.2011034**

[100] **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof**

- Obtaining exclusive land rights
- Executing the Environmental Impact Assessment
- Application for permits and evaluation
- Conclude the period for appeals and granting of irrevocable permit

The current expectation is that this development process would take 2 to 3 years for large scale electrolysers[101]. The period from financial investment decision until the start of operation is expected to take 5 years, leading to a total timeline of 7 to 8 years[101]. This timeline is based on current expectations, over time the realisation duration may decrease in case permitting processes are streamlined, activities are undertaken in parallel, and technical maturity of large-scale electrolysers increases.

For offshore wind sites, analogous activities are executed by the national government as part of the one-stop-shop regime. If such development activities for onshore electrolysis could be successfully undertaken by the government as well, it could reduce the realisation duration by 2 to 3 years.

Spatial planning for large scale electrolysers is challenging. The area required for a 1 GW-scale electrolysers is substantial, ISPT estimates about 10 hectares per GW[102]. Land ownership is spread between governmental agencies (such as *Rijksvastgoedbedrijf, Bureau Beheer Landbouwgronden*, provinces, *waterschappen*, municipalities) and private owners. Providing exclusive rights and permits for onshore electrolysers involves many more stakeholders than offshore.

To effectively deal with spatial planning challenges in the Netherlands, a new law, the *Omgevingswet*, was developed, and the aim is to ratify the law by July 2022. The law aims to simplify and accelerate progress in spatial planning processes in the Netherlands. In this law, various instruments are defined that enable collaboration between different levels of government, and enable taking a strategic spatial planning approach to realise the energy transition. These instruments may be used to enable the government to play a driving role in realising large scale onshore electrolysis.

The national government formulated the “*Nationale Omgevingsvisie*” (NOVI), which includes proposed focus areas (*NOVI-gebieden*)[103], as focus areas where the national government with regional stakeholders provide an additional impulse and support to NOVI-related transitions. The five industrial clusters are included in *NOVI-gebieden*, which enables accelerated decision making and streamlining collaboration between national and regional governments[104]. Including large scale electrolysis initiatives in the *NOVI-gebieden* plans, may facilitate realisation.

On a regional level, the *Regionale Energie Strategie* identifies different roles that provincial and municipal governments could play in the development of renewable energy projects[105].

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[101] Information provided by Gasunie & NorthH2

[102] **https://ispt.eu/media/Public-report-gigawatt-advanced-green-electrolyser-design.pdf**

[103] **https://denationaleomgevingsvisie.nl/samenwerking+en+uitvoering/novi+gebieden/default.aspx**

[104] **https://www.denationaleomgevingsvisie.nl/publicaties/novi-stukken+publicaties/HandlerDownloadFiles.ashx?idnv=1760378**

[105] **https://www.regionale-energiestrategie.nl/ondersteuning/handreiking2/downloads_getfilem.aspx?id=1365029&forcedownload=true**

1. Facilitating role: a role where the government creates the framework that enables acceleration of realisation. This may include market consultation, site selection, and supporting the public participation process.

2. Stimulating role: an active government role, which could include granting of subsidies and carrying out development activities (such as site studies).

3. Directive role: the government collaborates with the market to realise projects and participates as a shareholder.

In order to facilitate the spatial planning and permitting processes, a facilitating role or stimulating role may be appropriate. An important consideration is the novelty of large-scale electrolysers. A key question is whether it would be possible for a governmental agency to define a basic design (bandwidth) with sufficient certainty, that it (a) enables environmental impact assessment, (b) while being fit-for-purpose for the final design and realisation of the electrolysers. Electrolyser technology is under development, with competing sub-technologies with different characteristics and spatial footprint requirements. We recommend engaging with electrolyser manufacturers, and electrolyser developers to understand whether the definition of a design bandwidth is possible and by when.

In case it is not possible in the short term to define an appropriate design bandwidth, the active governmental role can be focussed on *streamlining* the spatial planning processes (including facilitation of land rights) and streamlining permit processes, while the actual execution of the environmental impact assessment and permit application process would remain responsibility of the developer. An instrument that could be used to increase the ability to direct the location of electrolysers is a societal tender (in Dutch: *maatschappelijke tender*)[106]. This would allow to define electrolyser search areas, in collaboration with TSOs, hydrogen offtakers and other stakeholders. This instrument can also be used to facilitate local process participation, which may increase local acceptance for electrolysers. It can be tied in with joint programming of the roll-out of wind, new demand, and infrastructure (which is further explained in section 5.5), and different combinations with the tendering of offshore wind (refer to section 7.1.2) are possible.

Offshore electrolysers

For offshore electrolysers, we distinguish between integrated and centralised electrolysis.

For **integrated electrolysis**, the electrolysers are an integral part of a wind farm. Thus, the responsibility for realisation and operation of the electrolysers in this case lies fully with the wind farm developer.

For **centralised electrolysis**, there are three main options to consider:

1. Ownership & operation by **wind developer**: In this case, the wind developer can sell the produced hydrogen to an offtaker onshore. As an implication, the electrolyser capacity is linked to the capacity of a single wind farm. In case the electrolysers are operated by the wind developers, it is necessary to provide clarity on the available space and infrastructure, and associated tariffs for use of the substructure, prior to publishing the offshore wind tender. The design of the centralised location requires collaboration between the party responsible for the

[106] **https://www.regionale-energiestrategie.nl/ondersteuning/handreiking2/downloads_getfilem.aspx?id=1364970&forcedownload=true**

island/platform, the party responsible for the transmission infrastructure, wind developers, and electrolyser developers.

2. Ownership & operation by a **third party that produces and trades hydrogen**: In this case, the wind developer sells its electricity to a third party that owns and operates the centralised electrolyser. The produces hydrogen is traded by the party. The electrolyser may have a larger capacity, overarching several wind farms.

3. Ownership & operation by a **third party that provides conversion as a service**: In this case, access to use the electrolyser is provided to the wind developer by the third party. While the third party owns and operates the electrolyser, it does not become owner of the produced hydrogen, as it provides conversion as a service. The wind developer owns and trades the produced hydrogen.

The choice of the option depends on the size of the electrolyser. In case of centralised electrolysis with a capacity equal to a single offshore wind farm, there are no substantial disadvantages to making the wind developers responsible for realising the electrolysers. However, in case of larger scale centralised electrolysis, the alternative models are worthwhile considering. The following Table 5-3 sets out the main pros and cons of the three models.

Table 5-3 Pros and cons for different models for offshore electrolysis

Model	Pros	Cons
Wind developer owned	• Wind farm developers can market hydrogen to multiple offtakers • Reduces number of offshore interfaces	• Limits economies of scale for the offshore electrolysers • May require a larger total footprint due to duplication of systems/assets • Forces wind farm developer to develop electrolysers
Third party – hydrogen trader	• Enables realisation of electrolysers at a scale larger than a single wind farm, resulting in economies of scale • Larger scale electrolysis may reduce the total required footprint	• Limits energy offtakers and trading possibilities available to wind farm operators • Offtaker lock-in may result in a less profitable business case for wind farm operators • Adds an offshore interface between wind farm and electrolyser
Third party – conversion as a service	• Enables realisation of electrolysers at a scale larger than a single wind farm, resulting in economies of scale • Larger scale electrolysis may reduce the total required footprint • Does not result in offtaker lock-in of wind farm operator	• Adds an offshore interface between wind farm and electrolyser • Fundamentally changes the business model, which may deter some investors

Based on the above, the wind developer owned and third-party conversion as a service models may be preferable over a third party hydrogen trader model. The comparison, including mitigation considerations, is further detailed below.

There may be options to mitigate some of the cons of including electrolysers in the scope of the wind turbine developers. One disadvantage is the limited economies of scale. A mitigation option may be to share the balance of plant (incl. water and gas treatment, civil works) of the electrolysers between the electrolyser operators.

A disadvantage of the third-party option where the third-party becomes owner of the hydrogen is the offtaker lock-in. The model where a third party provides conversion as a service could provide mitigation to this risk. For example, tolling agreements could be used. These have been applied already in the electricity production and liquified natural gas sectors[107], or the open-access model of for instance Gate Terminal[108]. The premise is that wind farm operators pay a fee to an electrolyser operator for the service of energy conversion. The wind farm operators would retain ownership of the produced hydrogen, enabling further trade and sale of the hydrogen.

Some parties in the working group indicated that the economies of scale for large-scale onshore electrolysis start levelling off once reaching the GW-scale, but whether this is the case for offshore electrolysis as well requires further investigation. If this is the case for offshore electrolysis as well, it would mean that the (normalised) cost level of an electrolyser with a capacity that is based on a single wind farm is similar to the cost level of an electrolyser of a scale of multiple wind farms. If this is the case, we consider it preferable to include the electrolyser in the scope of the wind farm developer, as it provides greater access to the offtaker market.

Considering the maturity of offshore electrolysis, and the residual questions that require further investigation **it is not possible to conclude which governance model for centralised offshore electrolysis is best suited**. Thus, we recommend to at this stage retain optionality to apply different governance models going forward.

5.4 Masterplan

At the core of the current governance system for offshore wind in the Netherlands stands the *Routekaart Windenergie op Zee 2030*. A new offshore wind roadmap until 2040 is currently being prepared. The offshore wind roadmap focuses on identifying search areas and sites for offshore wind developments and defines the type of transmission infrastructure at the publication of the roadmap.

Towards 2040, the offshore wind roll-out becomes more complex due to uncertainty with regards to increasing considerations for electricity and hydrogen demand growth, the speed of development of electrolysis and hydrogen infrastructure and greater coordination requirements for onshore and offshore infrastructure. The decision of which infrastructure is used to connect search areas must be informed by an appraisal of electricity and hydrogen supply & demand developments, infrastructure requirements and realisation timelines. To ensure alignment between these different elements, coordination by the government is required.

We propose considering developing a **masterplan**. The masterplan is a step-by-step decision process which is undertaken on a rolling basis. The masterplan provides more

[107] King & Spalding, Third Party Tolling Agreements, **https://www.kslaw.com/blog-posts/third-party-tolling-agreements**
[108] **https://www.gateterminal.com/en/gate-terminal/faq/**

adaptivity, long-term vision and coordination compared to the offshore wind roadmap. It enables taking a comprehensive view of the energy system into the decision-making process. It is not a replacement for the offshore wind roadmap, but it is in essence an expansion of the offshore wind roadmap, as it starts earlier and has a broader scope. The masterplan is adaptive as it can respond to technology and demand developments into the decision-making process.

In this chapter we explain the timeline and decisions of the masterplan (5.4.1), the factors that should be taken into account when deciding between infrastructure configurations (5.4.2), and how this masterplan relates to meeting the 2030 targets (5.4.3).

5.4.1 Timeline and decisions in the masterplan

For the masterplan, we recommend following the process as visualised in Figure 5-3.

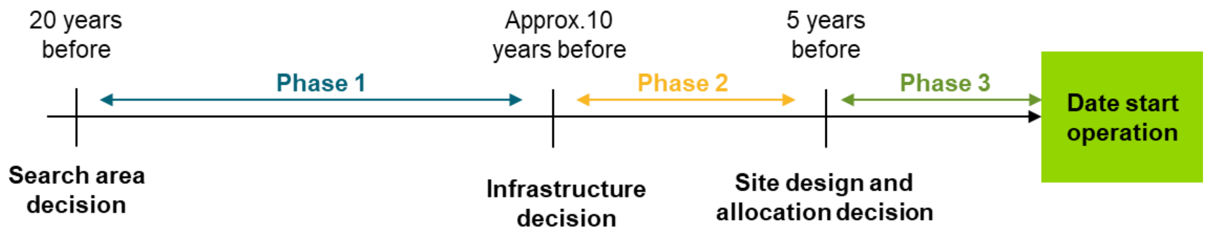

Figure 5-3 Masterplan process for offshore wind roll-out

The process consists of three decision moments leading up to the start of operations, resulting in three distinct phases. The rationale of the process is to provide sufficient time for the realisation of new infrastructure, to provide clarity and predictability to all parties involved and enable the supply chain to respond.

The decisions and phases are listed in chronological order, and for each phase we discuss the degree of adaptivity that is provided within the phase:

- **Search area decision**: Approximately 20 years before the targeted date of operation, the government identifies the search areas where offshore wind can be developed. The search areas currently identified are based on the *Programma Noordzee 2022-2027*, which seeks to accommodate up to 38 GW. The search area identification and decision in the masterplan can follow the same approach as currently done under the *Programma Noordzee 2022-2027.*

- **Phase 1**: During the following (approximately) 10-year long phase 1, pre-feasibility studies for the search area and more in-depth studies regarding the infrastructure decision are performed by the government (a similar working group can be set up). The government should develop a short-list of possible connection configurations and undertake the activities that are needed to timely realise the infrastructure. Depending on the asset type, varying degrees of pre-development may be needed before the infrastructure decision can be taken. For example, an energy island will likely require more pre-development than a radial electricity connection.

  During this phase, a broader infrastructure development plan should be developed, that takes into account developments (supply, demand, infrastructure) onshore and offshore in an integrated way. This should be done in close collaboration between the TSOs/HNO(s) and government. This infrastructure development plan feeds into the search area and wind site specific offshore infrastructure investigation and decision.

- *Adaptivity during phase 1: selection which wind area to develop, capacity of wind area, selection of configuration type (electricity, H_2 centralised, H_2 integrated, hybrid), selection of land fall location*

- **Infrastructure decision**: Approximately ten years before the targeted date of operation, the government determines:

  - which wind area(s) will be connected,
  - which energy carrier will be used to transport wind energy to shore (electricity, hydrogen, both),
  - what type of offshore assets will be used (platforms, artificial islands, pipelines, cables),
  - whether existing assets are re-used,
  - whether interconnection will be realised,
  - the capacity (bandwidth) of the assets; and
  - the onshore landfall location.

  The infrastructure decision will be made in close collaboration with the TSOs, industry and the wind sector and with due consideration of the considerations included in the joint offshore wind – industry roadmap (see section 5.5).

  The ten-year time horizon for the infrastructure decision is an approximation. For example, realisation of an energy island will likely require several years longer[109]. A radial electrical connection may also be possible within 8 years. Currently, onshore electrical infrastructure has a lead time of around 10 years. In case the *Omgevingswet* leads to more stringent permitting processes and requirements this may increase the lead time to 12 years, according to TenneT. To enable the timeline of 10 years to start operations, an acceleration of the onshore electricity infrastructure development process would be necessary (particularly the permitting procedures), or some development work needs to be started at-risk, prior to the infrastructure decision. If this is not possible, a longer lead time between the infrastructure decision and start of operations may be necessary. In contrast to electrical connections, hydrogen pipelines have a shorter lead time of 3 to 5 years for retrofitted pipelines or around 6 years for new pipelines. Thus, wind farms connected only by hydrogen pipelines, which do not require a substructure such as an artificial island (which has a long lead time), may be realised in a shorter timeframe, thus provide an opportunity to accelerate the roll-out. To account for these different variances, it is important to start 20 years in advance with the search area decision.

  Depending on the asset type, modularity and over-dimensioning of infrastructure could be considered to increase adaptivity. For caisson islands or distributed hubs, modularity may be achievable at acceptable cost levels. For sand-filled islands, modularity is costly, while over-dimensioning might result in a more future proof asset. Over-dimensioning hydrogen pipelines at the start of the development is not adding a significant anticipatory cost, as pipeline cost is rather insensitive to capacity. The costs and benefits of modularity and over-dimensioning should be examined on a case-by-case basis.

[109] **https://northseawindpowerhub.eu/sites/northseawindpowerhub.eu/files/media/document/NSWPH-Topical-Agenda_Final.pdf**

- **Phase 2**: During the subsequent phase 2, the applicable TSO/HNO(s) and/or PPP(s), carry out detailed design, contracting and permitting. Depending on the fabrication and construction duration, the TSO/HNO(s) and/or PPP(s) take financial investment decision somewhere during phase 2. Anticipatory investments are likely required, as the wind farm tenders still need to take place, and the infrastructure capacity could be greater than a single wind farm.

  The government in parallel continues to pre-develop the site. This includes definition of the site, defining the design bandwidth for wind developers, running the environmental impact assessment and permitting process. The *Kavelbesluit* and tender documentation is developed.

  - *Adaptivity during phase 2:*
    - *Until infrastructure FID is taken: refining planning of infrastructure realisation, infrastructure design modifications (while energy carrier is fixed), refining the routing of infrastructure*
    - *Wind farm site design (verkaveling), modification of bandwidth for wind turbine developers (e.g. number of wind turbines, total swept area rotors)*

- **Site design and allocation decision**: Approximately 5 years before the start date of operation, the government publishes the site decision, issues and executes the tender and awards a project developer. The site-by-site decision can be taken by ministerial decree, analogous to the current process for offshore wind. Note, in case tenders for offshore wind and onshore electrolysis, the five-year window might be too short to realise a large-scale electrolyser.

- **Phase 3**: During the following five-year long phase 3, the successful project developer continues development, takes final investment decision, and fabricates and constructs the wind farm. The TSO/HNO(s)/PPP(s) continues to develop and realise the infrastructure. Bilateral agreements between the project developer and infrastructure operator(s) are realised.

  - *Adaptivity during phase 3: wind farm developer can refine the detailed wind farm design, wind farm developer has limited room to shift start date operations (subject to the realisation backstop date)*

5.4.2 Factors determining the connection configuration

Taking the infrastructure decision (which energy carrier(s) are transported to shore and which type of assets are used) ten years in advance of the date of operation of the offshore wind farm requires strong governmental decisions**.** We recommend basing the decision of how to connect a certain search area on the following elements:

- Assessing the required **growth pace and absolute volumes of renewable electricity and green hydrogen** that are needed to meet energy and climate targets.

- An analysis of **green hydrogen and electricity demand** and a **projection of the growth of other generation assets** besides offshore wind. Programma Energiesysteem could be the basis for such an analysis. Within the Program, an recurring outlook of the development of the energy system and well as a National Energy Plan 2050 (Nationaal Energieplan 2050) will be developed. It could serve as input to periodically assess the roll-out of offshore wind and to inform choices regarding energy carriers and infrastructure.

- The availability and supply of expected green hydrogen and electricity **import and export volumes** from other European countries. This also requires a political decision on the extent to which the Netherlands wants to be (in)dependent on foreign energy supply.

- Appraisal of **interconnection opportunities** (and value thereof) with neighbouring countries, impact of different offshore market models

- **Modelling by the TSOs** to understand onshore congestion challenges for the different alternatives

- **Insights from the market** on what is technically and economically feasible, gathered through periodic consultations

Regarding the first bullet point – meeting targets – we recommend for the government to **set out a goal for the targeted domestic production volumes of green hydrogen by 2030 and 2040**. To invest in electrolysers, industry actors need clarity on the regulatory framework. A clear direction is provided by the proposals included in the Fit for 55 package, however, these will be under negotiation for quite some time. To provide investors with sufficient certainty, a domestic green hydrogen production target could be set. This would also provide more clarity on the respective shares of domestic production and imports in supplying the demand. The goal should be time-bound and feasible so that the market can react and plan accordingly. The goal should be integrated into the national H_2 strategy. Setting such a goal, could be informed by a joint offshore wind – industry roadmap, which is further discussed in section 5.5.

Moreover, the infrastructure decision requires location specific considerations regarding:

- Total potential offshore wind capacity of the search area

- Distance from shore

- Proximity to other search areas

- Proximity to offshore wind developments and offshore infrastructure abroad

- Proximity to offshore gas infrastructure and opportunities to repurpose existing gas infrastructure[110]

We recommend repeating this process in two-year intervals.

5.4.3 View on the realisation of the wind and electrolysis targets for 2030

The current national offshore wind capacity target for 2030 is expected to be increased to 21.5 GW, which is a combination of the 2030 target of the *Klimaatakkoord* (11.5 GW) and the addition of 10 GW stemming from the *Extra Opgave Industrie* published in 2021.[111] The State Secretary of the Ministry of Economic Affairs and Climate Policy has announced spatial procedures will be started for the offshore routes and landfalls of 12 GW[112], in addition to the current Offshore Wind Roadmap. The *Ontwerp Programma Noordzee 2022* –

[110] Note, in the study Systeemintegratie wind op zee 2030-2040, it is argued that the main asset of interest for repurposing are offshore gas pipelines. The main benefit is being able to repurpose the actual asset, or repurposing the routing, which eliminates or alleviates a lengthy permitting process.

[111] In spring 2022, the Extra Opgave for the built environment and mobility will also be published.

[112] **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/02/kamerbrief-over-verkenning-aanlanding-wind-op-zee-2030-vawoz**

2027 aims to find sufficient sites to accommodate at least 38 GW. Figure 5-4 shows the location of the wind search areas.

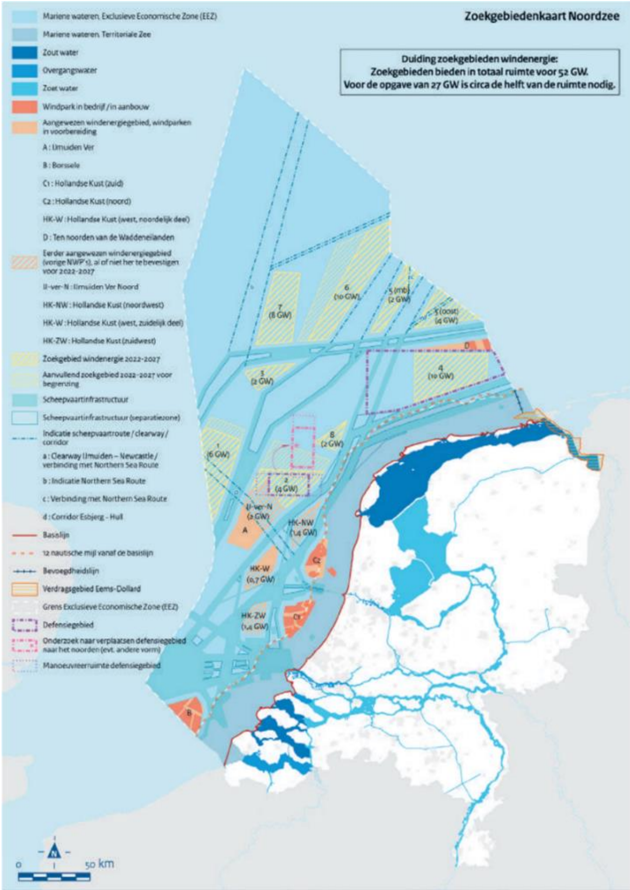

Figure 5-4: Map of Ontwerp Programma Noordzee 2022-2027 with the location of the wind search areas

The additional wind search areas that are considered for the acceleration up to 2030 are IJmuiden Ver (noord), area 1 and 2 (off the coast of Noord-Holland, next to the IJmuiden Ver area) and area 5 (oost) (north of the area Ten Noorden van de Waddeneilanden). Up to 2030, the State Secretary did not yet envisage the large-scale application of offshore electrolysis, and assumed the connections of the offshore wind farms to shore will be electrical. From the total acceleration of 10 GW, the Ministry anticipates that due to various challenges, 4 GW will be realised by the end of 2031. Due to the tight timelines, some infrastructure options, such as large-scale energy islands may not be timely feasible. Thus, adaptivity of the offshore infrastructure up to 2030 (and possibly 2031) is expected to be limited to infrastructure options with a fairly quick realisation period.

The Climate Agreement has a 2030 ambition for installed electrolyser capacity of 3 to 4 GW. The State Secretary of the Ministry of Economic Affairs and Climate Policy estimated that if the Fit for 55 RFNBO targets would become binding, this may result in a green hydrogen demand of 14 – 31 TWh and that it would require 4 to 12 GW of electrolysis to supply this demand.[113] Realising these significant electrolyser capacities in the coming 8 years is challenging due to the following reasons:

[113] **https://www.rijksoverheid.nl/documenten/kamerstukken/2021/12/10/kamerbrief-over-marktordening-en-marktontwikkeling-waterstof**

- The lead time for large scale onshore electrolysis, from pre-development to the start of operation, is expected to be about 8 years (pre-development and consenting are expected to take 2 to 3 years, and the period from financial investment decision to start operations expected to take 5 years)[114].

- There is no final clarity yet on the sustainability criteria for green hydrogen, stemming from the Delegated Act.

- National policy that would provide investors sufficient certainty to develop large scale projects is not yet in place.

Realising the 2030 electrolysis ambition requires setting a clear regulatory framework in the short term (i.e. in 2022), as large scale onshore electrolysers may take up to 8 years to realise. As set out in section 5.3, a directive role of the national government in spatial planning of large-scale onshore electrolysers could help to speed up timelines.

This timeline also implies that in order to coordinate the timing and location of large-scale electrolysers with the realisation of new offshore wind capacity, coordination should be done with offshore wind sites that are already in the current roll-out pipeline (including the additional 10 GW from the *Extra Opgave*).

Finally, the Delegated Act on sustainability criteria may restrict the project configurations that are feasible and may also require coordination in time between new offshore wind farms and the electrolysers coming online. These considerations are further detailed in section 6.2.

5.5 Joint offshore wind – industry roadmap 2040

The Netherlands and all other Member States of the EU have committed to climate neutrality by 2050. As an intermediate step, Member States have agreed to increase the GHG reduction goal to minus 55% by 2030. In the coalition agreement, the new Dutch government has agreed to focus policy on greater reductions, which will amount to approximately 60% in 2030.[115] After 2030, the aim is to achieve a 70% reduction by 2035 and 80% by 2040.

As a result, the demand for electricity from renewable energy sources will increase rapidly. Electricity from RES is used to either supply current electricity demand, electrify demand currently supplied by other energy carriers such as natural gas, or to produce green hydrogen and derivatives. The State Secretary of the Ministry of Economic Affairs and Climate Policy estimated that if the Fit for 55 RFNBO targets would become binding, this may result in a green hydrogen demand of 14 – 31 TWh and that it would require 4 to 12 GW of electrolysis to supply this demand. In the same letter to parliament, the State Secretary indicated this would require at least 6 GW of offshore wind to facilitate this hydrogen production, without detriment of decarbonisation of other electricity use. Currently, there are no updated targets yet for the Dutch electricity mix in 2030 and 2040 or more precisely the share of renewable electricity therein. Such clarity will however be needed soon.

The successful rollout of offshore wind towards 2040 requires a policy framework that is created with a view on the whole value chain related to offshore wind, i.e. also the infrastructure and demand side. Infrastructure is an essential element of the offshore wind value chain as it is required to connect supply and demand. This holds true both for electrical infrastructure and pipeline infrastructure for green hydrogen. The spatial preparation and

[114] Source: input from Gasunie & NorthH2

[115] Source: **https://www.government.nl/binaries/government/documents/publications/2022/01/10/2021-2025-coalition-agreement/2021-2025+Coalition+agreement.pdf**

realisation of offshore wind farms, landings, infrastructure, and projects for making industry more sustainable must always be well aligned. Supply and demand can no longer be developed separately.[116] While most of this report focuses on offshore wind farms and infrastructure, we also want to take the demand-side into focus in this section.

There are numerous pieces of legislation or policy programs targeted at the demand-side. At **EU level**, these include for example the EU ETS and the proposed RED II revision as part of the Fit for 55 package with its proposed RFNBO quota. In the Netherlands, the following programs are especially relevant:

- **Programma Infrastructuur Duurzame Industrie** (PIDI): PIDI stands for the National Sustainable Industry Infrastructure Programme, in which stakeholders (governments, industry clusters, infrastructure companies, energy producers) work to accelerate decision-making on energy infrastructure. The basis for the plans comes from the cluster energie strategieën (CES). Based on the CES, parties make agreements for the execution of exploratory studies and FEED studies within the PIDI framework.

- **Meerjarenprogramma Infrastructuur Energie en Klimaat** (MIEK): The infrastructural consequences of the CES are included in the Multi-Year Programme for Infrastructure and Climate (MIEK). MIEK provides a strategic vision of the main infrastructure and system integration with a periodic assessment framework in consultation with industry and infrastructure companies. In MIEK, the coordination and direction of infrastructural projects that are essential for the energy transition are raised to the level of the national government.

- **Routekaart Elektrificatie:** The roadmap shows how the Netherlands can achieve large-scale electrification of industry. By 2050, 80 to 130 TWh of industrial energy demand will be electrified, or at least 60 per cent of the total demand. The roadmap outlines the potential for electrification within the industry, under which conditions this potential can be unlocked and how the resulting additional electricity demand will impact the electricity sector and national CO_2 emissions.

- **Verkenning aanlanding wind op zee** (VAWOZ): VAWOZ forms the connection between the North Sea Programme 2022-2027 in which the offshore wind energy areas are designated on the one hand and the PIDI on the other hand. The landfalling programme looks at promising cable routes and landfall locations for additional offshore wind energy before 2030 (acceleration task) as well as for landfall options for wind farms to be built between 2031-2040. The program looks amongst other elements also at demand for energy around the landfall location.

- **Programma Energiesysteem** (PES)[117]: The PES consists of three components: outlook, national energy system plan 2050 and integrated programming. PES will take an integrated view and make connections between the programs for the sectors of industry, electricity, mobility, and the built environment. The plan provides clarity about the government's role in creating the energy system of the future, from now until 2050. The plan does not give a fixed final picture and will partly have the character of a roadmap, with feedback loops so that innovations and social developments can always be adequately anticipated.

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[116] This is a conclusion also being derived in the letter by EZK to parliament on VAWOZ. Source: **https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557**

[117] Source: **https://www.tweedekamer.nl/downloads/document?id=05707050-1bb2-4dd5-a922-fb4387c4d92c&title=Naar%20een%20nationaal%20plan%20voor%20het%20energiesysteem%202050.docx**

- **Roll-out plan for an onshore hydrogen network:** A roll-out plan for an onshore hydrogen network is currently being developed, with the intention to send this to parliament in the spring of 2022[118].

- **SDE++**: The SDE++ support scheme is a technology-neutral scheme under which certain demand decarbonisation projects (electric heating, electrolysis, use of residual heat) can apply for a subsidy. All technologies compete on the basis of CO_2 abatement costs. The subsidy provided is based on the unprofitable gap between the costs and benefits (e.g. avoidance of CO_2 prices, electricity market income) of a project.

- **Custom approaches (*maatwerk*) to reduce GHG emissions of largest emitters**: In its coalition agreement, the Cabinet expressed it intends to enter into binding agreements with the 10 to 20 largest GHG emitters in the Netherlands to reduce their GHG emissions[119]. It was also stated that these agreements will have a level of reciprocity, and that the government will facilitate the realisation of new energy infrastructure.

The right regulatory framework is needed for all the different kinds of demand; however, industry is the biggest lever and most relevant in the context of offshore wind, given the current large electricity demand volumes, the significant electrification potential and the proposed RFNBO quota for industry. The roll-out of offshore wind after 2030 will almost solely depend on the pace and shape of decarbonisation of the industry. There are dedicated infrastructure programs for industry (e.g. PIDI), a dedicated industry electrification roadmap and a dedicated roadmap for offshore wind. However, there is currently **no joint program that focuses specifically on aligning the speed and incentives for electrification or green H_2 use with the offshore wind roll-out towards 2040**.

Based on this identified gap, we recommend developing a joint program for offshore wind roll-out and the decarbonization of industry. A joint program can provide clarity and investment security to the market, align deployment timelines, and ensure coordination. The core element of the program could be a **joint offshore wind – industry roadmap 2040**. We recommend that the roadmap should learn from the success of the existing offshore wind roadmap. The offshore wind roadmap sets out on a year-by-year basis how much wind energy is developed in what locations. It thus covers volume, location, and time. It also provides a full overview of all offshore wind developments between the date of publication and 2030. The roadmap is followed closely by the government. This on the one hand proves the success of the roadmap itself and on the other hand provides a high level of stability and certainty of the regulatory framework (hence decreasing regulatory risks for investors).

For the development of the joint offshore wind – industry roadmap 2040, the below guiding questions should be discussed and considered. For each question, we provide a first, high-level answer or recommendation.

1. **What is the gap to be filled? Why is a joint roadmap necessary?**

    - The above review of the relevant policy programs and roadmaps showed that there are multiple programs covering parts of the questions surrounding industry (PIDI, MIEK, Routekaart Elektrificatie, SDE++). There is also dedicated policy on offshore wind (e.g. the offshore wind roadmap). However,

[118] **https://zoek.officielebekendmakingen.nl/kst-32813-756.html**

[119] **https://www.rijksoverheid.nl/regering/coalitieakkoord-omzien-naar-elkaar-vooruitkijken-naar-de-toekomst**

there is no joint program looking at both elements in connection to each other. This is the gap the joint offshore wind – industry roadmap 2040 could fill.

- In the context of this project, Guidehouse had numerous conversations and interviews with industry stakeholders. A recurring theme in the conversations was the concern of not having sufficient demand to ensure the further roll-out of offshore wind towards 2040. A joint program could alleviate these concerns and provide investment security for all stakeholders involved.

2. What is the goal of the roadmap?

- The goal of the roadmap is to align the deployment schedule of new offshore wind projects with decarbonization measures (direct or indirect electrification) in industry. Currently, these two elements are pursued separately. This is evidenced by the fact that there are separate roadmaps for electrification and offshore wind developments. Given the significant planned volumes of each and the need to build infrastructure in time to connect them (i.e. make anticipatory infrastructure investments), a joint program could be essential in ensuring timelines align.

- The roadmap should consider the masterplan process recommended in section 5.4.

3. Which elements should the roadmap include?

- The roadmap should clearly set out the reason why it was set up (see question 1) and the goal to be achieved by it (see question 2).

- The roadmap should include a summary of the main targets, schedules and dates determined for the development of industry decarbonisation efforts and offshore wind by other policies. For example, it should include the volumes, locations and dates included in the offshore wind roadmap and VAWOZ, the volumes set out in the *Routekaart Elektrificatie*, the national hydrogen ambition and infrastructure considerations.

- The heart of the roadmap should be a joint yearly schedule for offshore wind roll-out, industry electrification and green H_2 uptake until 2040. The offshore wind capacities to be installed need to be correlated with the projected electricity and green hydrogen demand by industry. The roadmap should also include information on the required electrical and pipeline transmission infrastructure. In this way, the network operators can formulate new investment proposals in accordance with the plans of industry, in line with the advice of the Taskforce Infrastructure Climate Agreement Industry and considering offshore wind developments.

- The roadmap should include a feedback mechanism in case a mismatch between offshore wind roll-out and demand is identified. The feedback mechanism should trigger discussions on necessary instruments on either offshore wind or demand side.

- The roadmap should also set out the policy instruments to be implemented to support alignment (see question 5).

4. Which actors/stakeholders should be included in the drafting of the roadmap?

- The roadmap should include a consultation process with local government levels to discuss permitting and potential sites for electrolyser developments, and to create local acceptance for developments in industry clusters.

- Besides governmental bodies, all relevant private sectors parties should be involved. The main benefit of this program is the joint consideration of offshore wind, industry, and infrastructure. A dedicated focus should be on involving industry representatives from the Dutch industry clusters.

- To create high buy-in and ownership in the drafting process as well as the eventual implementation, dedicated working groups could be institutionalised by law, similar to the *Klimaattafels* for the *Klimaatakkoord* process.

5. **Which policy instruments should be assessed?**

- The question regarding the policy instruments should be answered differently for different points in time. This is largely because significant changes and developments can be expected for the green hydrogen market. We assume that the period up to 2030 will be characterized by a market ramp-up and significant support levels. The period beyond 2030 will be characterized by liquid markets and high demand and supply volumes.

- For the short-term until around 2030, we would recommend discussing three instruments in particular: locational investment signals, industry cluster specific programs and Carbon Contracts for Difference (CCfDs) to enable the use of green hydrogen in industry. In the period up to 2030, a policy focus should be placed on enabling the market uptake of H_2, which requires decisive government support. Beyond 2030, H_2 supply and demand should be increasingly governed by a well-functioning and liquid market. This shift will be made possible through evolving market conditions and associated regulatory changes. By 2030, H_2 generation costs will be significantly lower, thanks to declines in the cost of renewable electricity and electrolyser technology.[120] At the same time, the competing fossil fuels will become more expensive due to higher carbon prices. As a result of these developments, the cost gap will be reduced. For the longer-term beyond 2030, we thus would recommend switching from support instruments to market-driven instruments, such as green hydrogen quotas for industry. Once markets have been established and green hydrogen production costs have decreased, the support through CCfDs can be ended and industry can be targeted directly with quotas.

- In the short term, firstly, we recommend investigating the implementation of locational investment signals for new electricity demand. The purpose of such a policy instrument would be to coordinate the development of new demand with infrastructure deployment. A better view on where future electricity demand will be, allows for more precise anticipatory infrastructure investments, which in turn reduces the risk of development timelines not aligning. Locational investments incentives could be provided by e.g. reducing municipal fees or land lease costs in identified priority areas or reducing grid fees for demand close to the coast.

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[120] Source: **https://static.agora-energiewende.de/fileadmin/Projekte/2020/2020_11_EU_H2-Instruments/A-EW_223_H2-Instruments_WEB.pdf**

- Secondly, we recommend discussing cluster-specific programs, i.e. specific decarbonization roadmaps for the industry clusters. The roadmaps should be tailor-made for the circumstances in each cluster, e.g. regarding the level of flexibility the cluster can provide, the type of industry located there and their energy demand profiles, the spatial availability for electrolysers, the availability of existing electrical and gas/H_2 infrastructure, the availability of H_2 storage, the geographic proximity to landing zones of offshore wind farms and more. Cluster specific programs can enable a more holistic view of the interplay of demand, supply, and infrastructure (i.e. the entire offshore wind value chain) at one specific location. The drafting of the programs should involve the relevant stakeholders closely. The cluster-specific programs could supplement the *Maatwerk* approach to decarbonise the largest GHG emitters, as introduced in the coalition agreement.

- The cluster-specific approach of the second policy instrument is at first view rather closely related to the *Cluster Energie Strategieën* (CES). In the CES, the industrial clusters have developed regional pioneering programmes to work on their sustainability plans for 2030, with a further view to 2050. All clusters are aiming for a combination of reduction options, such as: Carbon Capture (Use) and Storage (CC(U)S), electrification, residual heat, hydrogen, renewable gas, process efficiency and circularity. This quick review of CES shows that electrification or the use of green hydrogen are only one of many considered decarbonisation options and the source of the renewable electricity or green hydrogen are not considered at all. In the context of the joint offshore wind – industry roadmap 2040, all these elements could be considered in unison, enabling more targeted investments on demand-, supply- and infrastructure-side.

- Thirdly, we recommend assessing the need for Carbon Contracts for Difference (CCfDs). The aim of CCfDs is to facilitate industry investment in breakthrough abatement technologies based on green H_2. By offsetting the additional operating costs of such technologies, CCfDs de-risk long-term investment while also laying a foundation for green lead markets. CCfDs can be awarded to individual projects or by using tenders. We recommend having separate support windows for different industry applications, as the abatement costs for each application of green hydrogen are different. The party that has been awarded support would be guaranteed a certain price (strike price). However, the awarded party should also have the option to sell its product as green for a premium that remunerates the implied emissions reductions. In this case, no funding would be required. The labelling of climate-friendly basic materials could incentivise off-takers to pay such a premium.

5.6 Summary of recommendations

For offshore wind farm governance, the following recommendations were made:

- The one-stop-shop principle and coordination by the government should be continued for offshore wind farms.

For offshore infrastructure governance, the following recommendations were made:

- Electrical infrastructure realisation may follow the same governance as stand-alone offshore wind farms (we recommend that TenneT continues this activity).

- In case of offshore electrolysis, responsibility for wind farm specific infrastructure may logically sit with the wind farm developers.

- In case of shared offshore hydrogen infrastructure, we recommend strong representation of public interest, through assigning responsibility to either the onshore hydrogen network operator, or a public private partnership. We recommend to further explore these options with the existing offshore gas actors.

- Third party access to shared offshore hydrogen infrastructure is likely to become subject to the EU Gas Package and Regulation, in which case during a transition period until the end of 2030 negotiated TPA may be provided. After that, regulated TPA is required. We recommend for transparency in tariffs and conditions for connected wind farm developers at the time of a wind tender, which may speak in favour of regulated TPA.

- For shared substructures and energy islands, different considerations may apply than for hydrogen transmission assets. A directive role for the national government is envisaged. Depending on the scope, involvement of both the electricity TSO and onshore hydrogen network operator may be sensible. Involvement of the private sector (through a PPP) can be considered. Capacity allocation mechanisms and market models that enable greater interconnection require further investigation.

For electrolyser governance, the following recommendations were made:

- For a combination of offshore wind and onshore off-grid electrolysis, we recommend assigning the responsibility of the offshore infrastructure to the wind farm developer.

- For offshore electrolysis, a wind developer owned and third-party conversion as a service models may be preferable over a third-party hydrogen trader model. The wind developer owned model eliminates an interface, but may limit economies of scale. A disadvantage of the third-party option where the third-party becomes owner of the hydrogen (i.e. hydrogen trader model) is the offtaker lock-in. The model where a third party provides conversion as a service could provide mitigation to this risk. This warrants further investigation, considering the technical and regulatory uncertainties.

For the masterplan, we made the following recommendations:

- To ensure alignment and coordination between the various elements of future offshore wind roll-out, we recommend developing a rolling masterplan with three decision moments, approximately 20, 10 and 5 years in advance of the start of operations. Flexibility in the infrastructure decision is required, depending on the configuration, shorter or longer realisation times apply.

- We recommend repeating the masterplan process in two-year intervals.

- We recommend determining by ministerial decree which infrastructure needs to be developed by the applicable party for electricity or hydrogen infrastructure. We recommend building out the full capacity of the hydrogen pipelines from the start.

- We recommend that the decisions are made in close collaboration with the TSO/HNO(s), offshore wind sector and industry.

- We recommend basing the infrastructure decision on numerous factors, such as the required growth pace and absolute volumes of renewable electricity and green hydrogen that are needed to meet energy and climate targets.

- We recommend for the government to set out a goal for the targeted domestic production volumes of green hydrogen by 2030 and 2040.

- Realising the 2030 electrolysis ambition requires setting a clear regulatory framework in the short term. As set out in section 5.3, a directive role of the national government in spatial planning of large-scale onshore electrolysers could help to speed up timelines.

- We recommend for the government to coordinate the timing and location of large-scale electrolysers with the realisation of new offshore wind capacity already in the current roll-out pipeline.

For the joint offshore wind – industry roadmap, we made the following recommendations:

- We recommend developing a joint offshore wind – industry roadmap 2040. This roadmap should be developed in consultation with TSOHNO(s), the offshore wind sector, local government representatives and industry partners.

- As part of the roadmap, we recommend for the short-term until around 2030, to discuss three instruments in particular: locational investment signals, industry cluster specific programs and CCfDs. For the longer-term beyond 2030, we would recommend considering demand-side driven policy instruments, such as green hydrogen quotas for industry.

6. Allocation mechanism

The allocation mechanism determines the rules and processes according to which a specific offshore wind site is allocated to a bidder (i.e. a project developer). It can also determine the rules according to which support payments are distributed to a bidder.

The allocation mechanism is strongly connected to the infrastructure governance model (see section 5.2). Section 5.2 concluded that a governance model for the offshore developments with more responsibilities for the TSO and other governmental bodies is best suited up to 2040. This chapter focusses on the allocation mechanism under this governance model.

Looking ahead to 2040, the key question is what the **challenges and changes** are that need to be addressed through or considered in the allocation mechanism;

- There will be a significant scale-up in offshore wind capacities towards 2040, the allocation mechanism must be able to manage that.

- A greater interplay between offshore wind roll-out, onshore grid development and onshore demand development is expected.

- Development of offshore electrolysis may open up alternative infrastructure options, that can be considered in the allocation of sites.

- A concentration of the market on large enough actors for large-scale developments may occur, thereby impacting the level of competition.

Section 6.1 examines the allocation mechanism for offshore wind sites, while section 6.2 takes a closer look at the allocation of sites for the development of offshore wind and onshore hydrogen. Section 6.3 then examines the allocation mechanism for offshore wind and offshore hydrogen sites.

6.1 Offshore wind allocation mechanism

A recent revision of the law for offshore wind (Wet windenergie op zee), ratified in 2021, allows for four options for the allocation of offshore wind sites:

- a competitive subsidy award procedure,

- a comparative assessment without a financial component,

- a comparative assessment with a financial component, or

- a competitive auction.

Within this set of options, the government makes a site-by-site decision based on a market consultation on whether a certain site is tendered with the option of support or without. Currently, clarity on the allocation mechanism is provided relatively late in relation to the opening of tender rounds, which leads to uncertainty for the project developers. Considering the expected large scale-up of offshore wind capacities towards 2040 and the resulting high frequency of allocation procedures, a new approach which provides more clarity sooner may be required.

Therefore, the focus of this section is on developing options for an alternative allocation mechanism. This alternative allocation mechanism should provide the following elements:

- enhanced predictability for the project developers,
- continued learning from experience through market consultations,
- reduced transaction costs for the project developers,
- reduced entry barriers for new market parties,
- reduced administrative complexity, and,
- reduced subjectivity to changes in political climate.

Based on these criteria, we recommend considering using a **continuous allocation mechanism which is the baseline mechanism used for all offshore wind tenders.** Under a continuous allocation mechanism, there is a clear single award mechanism that would be used as a baseline, as opposed to a site-by-site decision on the allocation mechanism. Only in case of significant market changes would an alternative allocation mechanism be applied; in which case, this change must be communicated early on. The advantages of such a continuous scheme are the following:

- Project developers would have a clearer view on the allocation mechanism earlier on. This reduces risks, increases predictability and transparency, lowers entry barriers, and enables project developers to develop the required in-house resources to excel meeting the demands of the allocation mechanism.
- Market consultations will be maintained for technical and economic insights, so that project developers are still enabled to share industry experience, to identify substantial market changes and help refine the tender specifics and site decisions.
- The government reduces the complexity of the processes surrounding the allocation, thereby also reducing the organisational capacity required for a single allocation procedure. This is very important in light of the limited human resources available (see also section 2.1).
- The continuous allocation mechanism reduces the spectrum of allocation options, thereby also reducing the extent to which the political climate can influence the procedure. This again increases the predictability for the project developers.

A point of consideration in the continuous allocation mechanism should be the timing of decision-making. Currently, tender decisions are taken relatively late. While this enables in practice a learning from the previous tender round on the status of the market, it also means that the market is provided certainty at a late stage. Going forward, a consideration could be to run tender preparations in parallel rather than in sequence. The continued market consultations would still enable a direct consideration of the market status.

To participate in the tender, bidders must submit evidence that they fulfil the pre-qualification criteria[121]. Bidders and their bids typically need to comply with certain eligibility or pre-qualification requirements. These aim to ensure the seriousness of bids, i.e. to prevent

[121] In general, pre-qualification criteria can be divided into material and financial pre-qualification requirements. Material pre-qualification requirements entail standardized proof of project progress, such as an environmental permit, an approved zoning or development plan or a grid connection agreement. Financial pre-qualification requires bidders to present a bid bond when entering the tender and/or a completion bond upon being awarded a bid. This can be done via bank guarantees or a cash deposit in a designated bank account. The financial guarantee is usually linked to penalties, as the bid and completion bonds can be retained in case the bidder does not live up to its contractual liabilities, e.g. in terms of realising the project within the agreed realization period.

bidders from participating in a tender with no serious intent to realise the project, and to increase overall realisation rates. Ensuring timely project completion of these projects through adequate pre-qualification requirements should be considered given the strategic value of offshore projects, and the ambitious offshore wind deployment targets on the Dutch and European level.

The continuous allocation mechanism would still entail a limited scope for **site-specific considerations**. However, these considerations should then be communicated to project developers sufficiently early.

Within the continuous mechanism, there is room for adaptivity with a view to the criteria used to select the successful bidder (i.e. the **award criteria**). Award criteria determine the order of bids. Besides a price-based selection, whereby projects are awarded based on lowest support bid or highest financial bid, qualitative criteria, such as innovation, are also feasible.

- **Qualitative criteria** can be used in combination with a financial bid or alone. When used alone, the bids will be evaluated purely based on the quality demonstrated. When used in combination with a financial bid, it should be considered that the financial bid reduces the margin available to the project developer to invest in qualitative aspects such as innovation.

- The **financial bid** can either be capped or uncapped. An uncapped financial bid enables selection of a winner based on the bidders' willingness to pay alone, as it results in a single highest bidder. A capped financial bid may lead to a situation, where several bidders bid the cap and differentiation based on willingness to pay is not possible. In this case, qualitative criteria would be used in addition.

- Price-only evaluation of **support bids** is the most common method of subsidy bid evaluation in Europe. In case, a differentiation by support bid is not possible (e.g. because all bids are zero), a differentiation by willingness to pay demonstrated in a financial bid and/or quality is required. Combining a financial bid with a support bid is not recommendable, as the financial bid would be increasing the level of support required, thereby increasing the societal cost. A combination of a support bid with qualitative criteria can be considered in case the government wants to pursue certain policy objectives (such as increased innovation). In case qualitative award criteria in addition to the level of the support bid are introduced, possible impact of the effects this may have on the support level should be considered, as some qualitative criteria may result in higher required support levels.

Against the background of achieved cost reduction and zero-subsidy bids, the possible combinations of award criteria described above and potential future developments (either continuing the subsidy-free roll-out or failing with the subsidy-free roll-out and requiring support), we propose three options. These options are in line with the Offshore Wind Act. Options 1 and 2 are in accordance with the process of a comparative assessment with a financial bid and the competitive auction respectively. Option 3 is a combination of a competitive subsidy award procedure and a comparative assessment with a financial bid.

The three options are:

- **Option 1**: In line with the aim of continuing the subsidy-free roll-out, bidders are **restricted to zero-subsidy bids**. Bidders will be evaluated based on a **capped financial bid and qualitative criteria** (i.e. a comparative assessment with a financial component).

- **Option 2:** In option 2, bidders are also restricted to **zero-subsidy bids**. However, as an alternative to option 1, a larger emphasis on price could be implemented by uncapping the financial bid (i.e. a competitive auction). With an **uncapped financial bid**, a differentiation based on price is ensured and qualitative criteria are not required for differentiation.

- **Option 3**: In this backstop option, bidders are asked to **fill in their required support level** which could be positive or zero. In this primarily price-only approach, the support level is a result of the bids received with the lowest one winning (i.e. a competitive subsidy award procedure). In case of multiple zero-subsidy bids, the zero-subsidy bids will be evaluated based on a capped financial bid and qualitative criteria. Essentially, this option thus combines a competitive subsidy award procedure with – in case of multiple zero-subsidy bids – a comparative assessment with a (capped) financial bid.

Overall, the proposed continuous scheme provides the flexibility to be applied both during times of subsidy-free roll-out and continued in case a subsidy-free roll-out fails. The key question is **when to use which option**.

- For the **short-term**, where the current market situation makes a continuation of zero-subsidy bids likely, (**option 1 or option 2**) and this will ensure that:

    - public funds can be used for other purposes,

    - subsidies do not disturb the market and price formation therein, and that

    - the electricity of these new and unsupported offshore wind farms can be used to produce green hydrogen (as likely required by the forthcoming Delegated Act).

  The selection of a specific option depends on market conditions, policy objectives and the level of interest/competition. For the short-term, the current market situation makes continuation of zero-subsidy bids likely, which could be in the form of a capped financial bid with qualitative criteria (Option 1) or an uncapped financial bid (Option 2). We recommend careful consideration of market and supply chain conditions in selection a specific short-term option. An uncapped financial bid may result in higher competitive pressures than a capped financial bid and qualitative criteria. In case qualitative criteria are included, bidders may leverage their innovation capabilities to maximise scoring, while in case of an uncapped bid the willingness to pay determines the outcome.
  Any deviations over time – either on the general choice of the option, the bid cap or the qualitative criteria selected – should be communicated sufficiently early.

- For the **longer-term**, there are larger uncertainties with a view to the development of electricity wholesale market prices. These uncertainties directly affect the business case of the project developer. It may result in an unprofitable gap or windfall profits.

    - **If prices develop favourably** for the offshore wind project developers, **option 2** could be considered to enable extracting windfall profits and increase societal benefits. This would mean that bids would only be evaluated based on their ability to pay (i.e. the uncapped financial bid). Qualitative criteria in such an allocation mechanism do not play a role in the award decision: the long term the qualitative aspects of offshore wind farms may become market standard (and could be included as pre-qualification criteria). The choice for this option should be informed by the criteria detailed in section 6.1.2 and market consultation and should be communicated to the market sufficiently early.

- **If prices are not developing favourably** for the offshore wind project developers, **option 3** can be considered as a backstop option of support bids. However, at the same time, option 3 still entails a mechanism for a situation in which multiple zero-subsidy bids were made (i.e. a comparative assessment with a capped financial bid). Project developers are hence still encouraged to make competitive bids. The switch from option 1 to option 3 should be informed by market consultation and be communicated sufficiently early.

In sections 6.1.1 to 6.1.3 below, each of the three options is explained in more detail.

6.1.1 Option 1 – Qualitative criteria & capped financial bid

In option 1, an evaluation based on requested support level is not possible, as the system does not allow for support bids (i.e. it requires zero-subsidy bids). Instead, a multi-criteria assessment including both a capped financial bid and qualitative criteria is used. This section first explains the conceptual considerations for option 1, then the weighting of the qualitative criteria and financial bid, before looking in detail at qualitative criteria and then the financial bid.

For **option 1**, a combination of qualitative criteria and a capped financial bid was chosen. As mentioned previously, because the financial bid is capped, a situation may arise where multiple bidders bid the cap. In this instance, differentiation based on price is not possible. Hence, the capped financial bid is combined with the use of qualitative criteria which can ensure that a successful bidder is determined. Compared to an uncapped financial bid, the capped financial bid has the upside of reducing risks for the bidder and reducing the winner's curse[122]. This in turn reduces entry barriers for new market participants, who may (due to their lower experience in the market) have a higher risk of overestimating their ability to pay in setting a financial bid.

Between the two types of award criteria, the government must determine the applicable **weighting**. For example, price could determine 80% of the final grade and quality 20%. The weighting of the criteria has implications on how project developers determine their bid strategy, e.g. whether they invest more resources in quality or the financial component. One factor to keep in mind in this context is that project developers have a limited margin to spend on their bid. This means that both the financial bid and the qualitative criteria are linked closely, as they both affect the profit margin to be made from the tender. In line with the weighting communicated in the tender publication, the project developer will invest the higher volumes on the factor that is more important in the evaluation.

In the next paragraphs, we clarify our understanding of qualitative criteria and the financial bid.

There is a plethora of **qualitative criteria** that can be used, e.g.: cost of energy, annual generation amount, certainty of realisation, environmental benefits, innovation, or envisaged commissioning date. In past tenders, also an effective risk mitigation strategy, e.g. through the inclusion of a PPA, was evaluated positively (see section 8.1.1 for a discussion on PPAs). In the future, other criteria could also be considered, such as the ability to provide benefits to the broader energy system (e.g. the ability to provide base load) and the ability to

[122] The winner's curse is when the winning bidder submits an underestimated bid and is thus cursed by being selected to undertake the project.

better enable multi-use of the seabed. The applicable qualitative criteria should be selected in line with policy priorities. One element to consider in light of the frequency envisioned for the future is that the government should either be largely continuous in its themes of qualitative criteria included (i.e. continue focusing on innovation) or communicate changes early on so that the market participants can react. Another element to consider is the market's ability to fulfil ambitious qualitative criteria. For example, in the context of innovation, a sort of "seller's market" may emerge in which scarce innovation projects determine the tender winner. Such a narrowing could negatively influence the level of competition in the offshore wind tender, as the "market" for such innovations may be small and not transparent.

The evaluation of quality requires the involvement of an expert committee which reviews and evaluates in detail the information submitted by the project developer. This entails that qualitative criteria cannot provide the same transparency as price as to why a certain bidder was selected. It also entails that the bid evaluation takes more time compared to price. Despite these disadvantages, qualitative criteria are required to ensure a differentiation of bids. They do however also have upsides to consider. The inclusion of qualitative criteria in past tenders has led to significant activity and initiative when it comes to innovation. For example, the CrossWind consortium, developing a wind farm at the Hollandse Kust (Noord) site, will include innovations in wake control, energy conversion and storage and floating solar PV in the wind farm.[123]

We would recommend that once an element can be considered an industry standard (e.g. a certain environmental mitigation measure), it should be removed from the award criteria and included as a pre-qualification requirement (pass/fail criterion).[124] This will make the actual bid evaluation more comparable and transparent while still maintaining the high quality with regards to the characteristics of the project.

The second component of the evaluation - **the capped financial bid** – is a lump sum payment/concessional payment. The payment could either be made soon after the award (e.g. with HKW the financial bid had to be transferred within a month), at the start of operation or over a pre-determined period of time. The timing has implications on the business case of the developer:

- An early payment has a very high net present value (NPV), which weighs down the business case of the project developer.
- A later or extended payment has a reduced NPV and therefore a lower impact on the business case.

From the point of view of the government, there are also implications to consider:

- An early payment is a de facto suspensive condition for the project developer. If the project developer does not pay in time, the government soon has clarity and can initiate next steps (e.g. award the second-best bidder or reiterate the tender process).
- A later or extended has – as described above – a lower impact on the business case of the developer. This in turn may lead to a higher ability to pay.

[123] **https://www.crosswindhkn.nl/nl/innovaties**

[124] Depending on the specific award criterion, the legal feasibility of this recommendation requires further analysis. The current law only offers limited scope for this, namely only in the area of technical and economic feasibility. However, other criteria could also be included as an implicit pass/fail criterion.

A lump sum payment is more attractive than a production-based payment by the developer for every MWh produced. Such a negative bid would incentivise curtailment while there is still demand for electricity by the market (low but non-zero prices) and is hence not recommendable.

The cap for the financial bid could be informed by the business case of wind farms to ensure that it is within margin. The cap could also be increased over time if market parameters change. The decision could be based on previous market consultation to estimate how much market parties are willing and able to pay.

6.1.2 Option 2 – Uncapped financial bid

In option 2, bids are not evaluated using a comparative assessment, but purely on price, or more specifically their financial bid. To ensure a differentiation of bids based on price only, the financial bid must be uncapped. Uncapping the financial bids means that the government could potentially extract a higher payment from the developers than with a capped financial bid. A necessary pre-condition for uncapped financial bids is zero-subsidy bids.[125]

When the government requires bidders to make uncapped financial bids, it could consider using dynamic tenders, where bidders can react to other bidders' prices. Dynamic tenders offer bidders the opportunity to observe the development of the tender price and other bidders' bids during several phases and to adapt their bidding strategies during the tender process (see visualisation in Figure 6-1). Such a dynamic tender only works in combination with a price-only award criterion. The dynamic tender could reduce the winner's curse.[126]

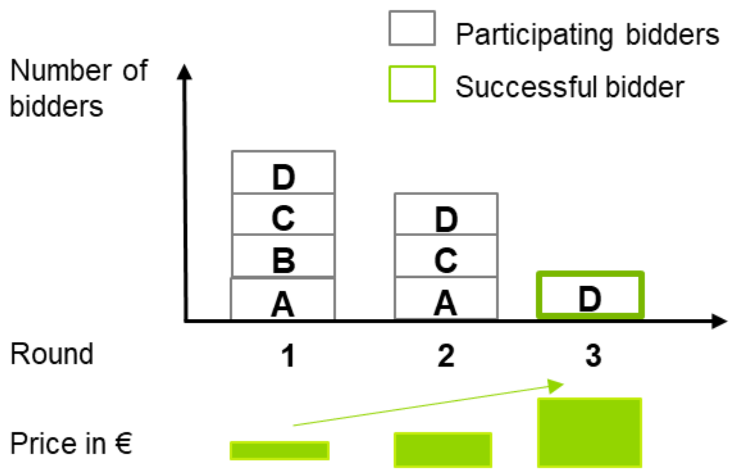

Figure 6-1 Schematic of a dynamic tender format

Whether uncapped financial bids are recommendable in a certain market situation depends on several factors. The government must assess whether:

- offshore wind technology is mature enough: this is already achieved today,

[125] In case of a support request and financial bid in the same round, the financial bid would drive up the support need which would in turn drive up the societal cost. This is not recommendable.

[126] In a capped system, a dynamic tender procedure would not be needed. Instead, we then recommend a static tender, i.e. all bidders simultaneously submit their bids, and bid prices are unknown to all other bidders. This format is called "static" because all bids are submitted only once, making it impossible for competitors to react to other bid decisions.

- there is sufficient competition in the market: this is already achieved today,
- market parties are well experienced: this varies between bidders, but in general experience is being developed quickly also by new market entrants,
- qualitative elements that are important for public interests have become market standards and can be defined as pre-qualification criteria: ecological mitigation measures are under development and system integration measures are very novel still, and, whether
- the surplus of projects is significantly large.

The last point – the surplus of projects (i.e. the ability to use profits for the payment of a financial bid) – is the most relevant and the most difficult to assess from the list.

International experience with financial bids is increasing. Reference cases from the US and the UK are not analogous to the Netherlands, as a support scheme is provided in those markets. The Thor tender in Denmark shows that bidders are in principle willing to pay a price to the government for the rights to develop a site, without support.[127] However, site characteristics need to be taken into account whenever trying to translate financials from one site to another. Furthermore, the wind industry is currently undergoing strain due to a combination of high commodity prices, and disruptions throughout the supply chain[128,129]. We recommend taking into account the health of the industry and its supply chain in deciding for an allocation mechanism.

Another key element to consider is the expected wholesale market price development in the Netherlands. However, here lies the crux both for the government and the project developers – future market price developments are highly uncertain. In the current situation where very high gas prices have led to increased prices on the electricity market and large windfall profits for companies, high financial bids would be feasible. However, in the future, with large offshore wind capacities installed, the issue of cannibalization and a greater share of renewables in general could put significant downward pressure on revenues for offshore wind operators. Besides these two examples, uncertainty comes from many more aspects including dependencies on demand stimulation, developments in other Member States, EU policy changes (such as the Fit for 55 package and its proposals for increased RES targets and RFNBO sub-targets), CO_2 price developments, material and commodity prices and technological advances. Depending on how all of these effects play out, project developers may comfortably make high financial payments, or, if effects play out negatively, project developers may be in need of support payments to realise the projects (see option 3).

The assessment of expected wholesale market prices and the resulting ability to pay should go hand in hand with market consultation. The discussions with the working group did not deliver a conclusive answer on when the conditions could be in place to warrant uncapped financial bids.

[127] **https://www.offshorewind.biz/2021/12/01/rwe-wins-danish-luck-of-the-draw-offshore-wind-tender/**

[128] https://seekingalpha.com/news/3798713-vestas-slashes-dividend-while-warning-on-further-supply-chain-disruptions

[129] https://www.reuters.com/business/energy/siemens-energy-ceo-siemens-gamesa-profit-warning-is-setback-2022-02-09/

6.1.3 Option 3 – Combination of support scheme backstop & qualitative criteria and capped financial bid

Option 3 is a backstop instrument in case the above-mentioned market price uncertainties develop negatively. If project developers cannot earn sufficient revenues from the wholesale market, they require support to realise the project. This option 3 includes the option of entering a support bid. In case of only positive bids or maximum one zero bid, the lowest bid is awarded. This will ensure the cost-effective support of offshore wind. The merit order of the bids will identify the winning bidder (see upper branch of Figure 6-2). In case the wind farm receives support, the renewable electricity can no longer be sold via a PPA to an electrolyser operator for the production of green hydrogen, as likely required by the forthcoming Delegated Act (see on this also section 6.2).

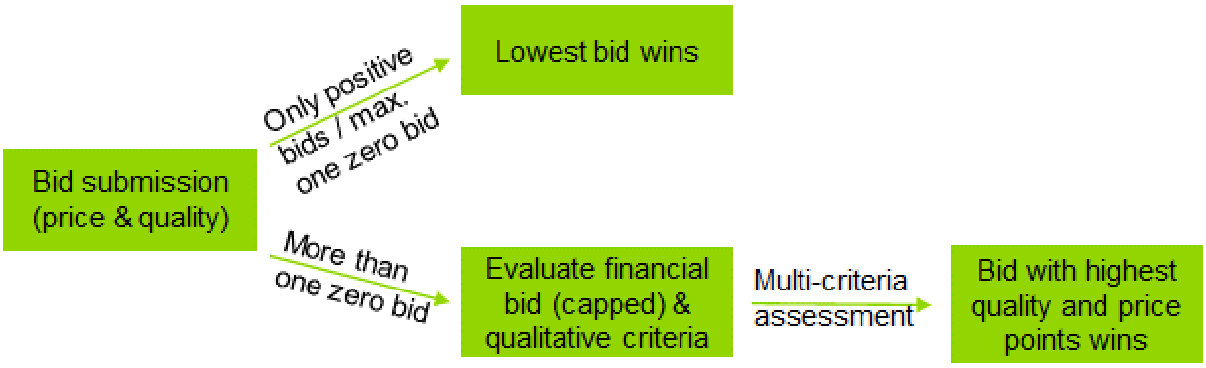

Figure 6-2 Evaluation of bids in option 3

In case of multiple zero-subsidy bids, the zero-subsidy bids would be evaluated using a capped financial bid and qualitative criteria (see lower branch of Figure 6-2). This assessment would be the same as in option 1 above.

Option 3 entails greater legal challenges than the previous two options due to the support bid option. Subsidies must be notified with and approved by the European Commission and must be reserved in the budget. In principle, it may be logical to arrange everything in advance for a subsidy in order to avoid delays. However, in practice, this may be difficult. State aid approval can be obtained more easily if a tender has not succeeded in being subsidy-free (i.e. option 1). The same holds true for making available budget to provide support.

As a result of this, it may be more feasible to first hold a tender under option 1 and only in case this tender has failed (i.e. no eligible bids were submitted), hold a second tender under option 3. This sequential process would entail a delay compared to directly implementing option 3. Such a delay may have negative implications for target achievement. However, at the same time, it could be argued that low interest in option 1 could indicate that demand is lagging or that the system cannot yet cope with the integration of more offshore wind. From a system perspective, this potential delay may thus not be a significant downside.

6.2 Offshore wind and onshore electrolysis allocation mechanism

While the previous section focused on the allocation mechanism for stand-alone offshore wind farms, this section focuses on the allocation mechanism for offshore wind and onshore electrolysis.

In the context of renewable energy, tenders are the standard allocation mechanism across the EU. For electrolysers, there are substantial uncertainties that may influence the selection of an optimum allocation mechanism, such as the Delegated Act of sustainability criteria. In this section, we derive and describe different tender options. For the eventual selection and detailed tender design, further discussion and analysis (e.g. on the impact of the designs on the cost of hydrogen production or on the duration of pre-development) are required.

Whilst deriving these options, we considered the following elements:

- The tender design should incentivise competition in both the offshore wind as well as the onshore electrolyser scope.
- The tender design should be lean and simple enough to ensure fast allocation procedures and therefore a fast deployment of new electrolyser and offshore wind capacities.
- The tender design should enable project developers to create a sustainable business case and reduce risks to the extent required.
- The tender design should enable the localisation of electrolysers in a system-friendly manner, i.e. in regions without grid constraints or “before” the bottleneck (close to the landfalls). The reason is that coordination of new electricity demand and supply enables mitigating grid congestion issues.
- The tender design should be coherent with the requirements of the soon-to-be-published Delegated Act on sustainability criteria. Please note that we are basing our considerations here on a leaked draft version. Based on this version, important elements to consider are:
    - On-grid electrolysers must have a PPA to cover their operating hours. The sourced electricity must come from a new, unsupported renewable energy resource. Newly built offshore wind farms could meet this additionality requirement. However, an offshore wind farm could be only used as a qualified PPA counterparty if it does not receive support payments. While this would be ensured under a continued subsidy-free roll-out, this requirement would become prohibitive in case the subsidy-free roll-out fails. On the upside, the offshore wind developer would likely be a much-desired PPA partner, as electrolyser operators require PPAs from such new and unsupported RES for their hydrogen production to qualify as “green”.
    - For off-grid electrolysers, the sourced renewable energy resource must come into operation in the same year as the electrolyser or later.
    - For on-grid electrolysers, the installation generating renewable electricity must come into operation not earlier than 24 months before the electrolyser.
- The tender design should be aligned with the electrolyser governance detailed in section 5.3. It is expected the government is not able to provide an equivalent “one-stop-shop” for electrolyser development compared to offshore wind. The governmental role in such case can be focussed on streamlining the spatial planning processes (including facilitation of land rights) and permit processes, while the actual environmental impact assessment and permit application process would remain responsibility of the project developer.
- The tender design should enable coordination (see Table 4-4 in section 4.2) between offshore wind and onshore electrolysis.

  - For off-grid electrolysis, the deployment of both assets – the offshore wind farm and the electrolyser – must be coordinated to reduce risk of stranded assets. The project developers of both assets are expected to enter into a PPA to regulate the delivery of electricity from the offshore wind farm to the off-grid electrolyser.

  - For on-grid electrolysis, coordination is required to avoid electricity grid congestion issues. Issues can be prevented by planning the location of offshore wind landfall and electrolysis as well as its timing.

Based on these considerations, we derived four options for tender designs. We differentiate them by the degree of coordination provided in the tender design:

- **Separate tenders** for the offshore wind and onshore electrolysis scope (no coordination)

- **Coordinated tenders** of the offshore wind and onshore electrolysis projects (in time and geography)

- **Joint tenders** of the offshore wind and onshore electrolysis projects

- **Integrated tender** of the offshore wind and onshore electrolysis projects and the green hydrogen offtaker

Each of the above tender options increases the intensity of coordination between both projects, as illustrated in Figure 6-3.

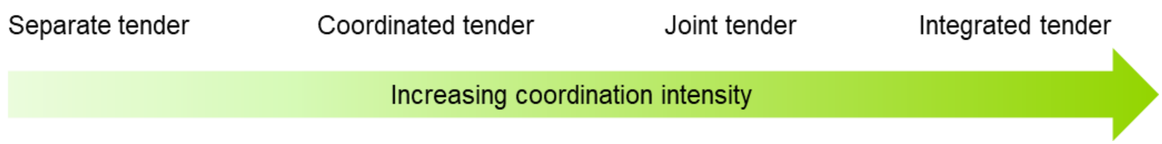

Figure 6-3 Tender options for offshore wind and onshore electrolysis

Separate tenders are the least coordinated option as the tenders are separate for the offshore wind and onshore electrolyser scope each. The tender schedules would be defined in line with target achievement roadmaps of either offshore wind or onshore electrolyser development, and the realisable project pipeline. Separate actors would participate in each tender. Much like today, we assume that the competition in each tender is high, enabling the effective implementation of a tender. Separate tenders are only possible if the electrolyser is on-grid (see chapter 4.2). Off-grid would be challenging to realise through separate tenders, as there is no direct connection between the offshore wind farm and the electrolyser created by the tender.

Alternatively, the government could implement **coordinated tenders**. Under this option, the auctioneer would have separate tenders for each scope (offshore wind and onshore electrolyser), however, the timing of each tender is coordinated by the government to ensure that (1) there is demand for electricity produced by the new electricity supply and (2) that the time thresholds that the Delegated Act will likely include for the assets to come into operation (one year or 24 months) are respected. Like before, it would likely be different actors participating in each tender, ensuring high levels of competition in each. Coordinated tenders are not suitable for off-grid electrolysers as the off-grid electrolyser requires a close relationship between the offshore wind scope and the electrolyser scope which is not provided by the coordinated tender.

For on-grid electrolysers, the government could define in which regions the electrolyser may be realised, based on input from the TSOs and in consultation with regional governments. The Delegated Act will likely enable Member States to define areas that are preferable for electrolyser deployment in view of congestion issues in the onshore electricity grid. Once a hydrogen grid is established, the location of the electrolyser should not be driven by proximity to the user, but by proximity to the offshore wind landing point, and proximity to the hydrogen backbone.

Given the coordination between the offshore wind and electrolyser scope through the timing and location of the assets, it is possible that the parties close a PPA. The PPA provides the offshore wind project developer with security of its revenues, while the electrolyser operator can use the PPA to comply with the currently drafted sustainability criteria from the Delegated Act. The likelihood of a PPA has a strong connection with the support needs. Electrolyser operators could receive support under a relevant support scheme. The offshore wind operator may – under the current expectation of the Delegated Act – not receive support if the electricity is to be sold via a PPA to an electrolyser operator for the production of green hydrogen. The options 1 and 2 described in section 6.1 above would ensure this. In option 3, bidders would need to make zero-subsidy bids, if the electricity is to be sold via a PPA to an electrolyser operator. Next to the support level, also the additionality of the wind farm must be considered. The coordinated timing will also ensure that both assets are built within the timelines that the Delegated Act will likely require. For on-grid electrolysers, the installation generating renewable electricity must come into operation not earlier than 24 months before the installation producing the renewable hydrogen.

We recommend to not directly couple the tenders economically, as it will incur significant transaction costs for the government which would first have to determine a PPA with the offshore wind developer that it then passes on to the electrolyser developer.

An even more coordinated option would be to implement **joint tenders** encompassing both the offshore wind scope and the onshore electrolyser in one tender. Bidders would be a consortium between the offshore wind developer and electrolysis project developer or a single developer that develops both asset types. The advantage of this is reduced counterparty risk as assets are combined in one tender. Joint tenders are possible for both on-grid and off-grid electrolysers. Off-grid creates incentives for the localisation of the electrolyser close to shore. For on-grid electrolysers, search areas should be pre-determined by the government according to the grid situation. Otherwise, the on-grid electrolyser could negatively impact existing grid congestion issues if no other countermeasures such as locational market signals are given.

Between the offshore wind farm and the on-grid electrolyser there will likely be a PPA. In the tender, support would only be provided for the electrolyser scope, as the Delegated Act is likely to require that on-grid electrolysers must use unsupported, additional RES capacity.

The most coordinated option is to implement an **integrated tender** including the offshore wind farm scope, the electrolyser, and the green hydrogen offtaker. In the Coalition Agreement[130], a company specific approach is described to decarbonise the 10 to 20 largest emitters in the Netherlands. This may speak to the use of a type of integrated tender. In the Hollandse Kust (west) tender, the inclusion of the creation of flexible demand could be considered working in a similar direction. Supporting integrated projects may be appropriate if there is a lack of transport infrastructure. This may be the case prior to 2030. An advantage of integrated projects is also the ability to address sectoral differences, as the

130 **https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/publicaties/2022/01/10/coalitieakkoord-omzien-naar-elkaar-vooruitkijken-naar-de-toekomst/coalitieakkoord-2021-2025.pdf**

implications and cost of transitioning to hydrogen differ between sectors. Integrated tenders may also reduce costs as the whole chain can find optimisations and share risks. Furthermore, due to the life cycles and useful lives of essential industrial infrastructures in some otherwise hard-to-abate industries such as the steel sector, an entry into green hydrogen use should be aimed for within the next few years in order to avoid lock-in effects. The IPCEI Hydrogen has an important role to play here due to its focus on integrated projects.[131]

Disadvantages of funding integrated projects are the relatively high funding costs associated with them and challenges in the selection process of the projects to be funded due to their lack of comparability. Moreover, integrated projects do not promote the development of a liquid market.

In the integrated tender, the bidder consortium would include all relevant parties to cover these three parts of the value chain (electricity production, hydrogen production, hydrogen offtake). Support would be paid to the hydrogen offtaker, who thereby gets a reimbursement for additional costs incurred by using green hydrogen instead of a fossil-based alternative. The support could be distributed e.g. in the form of a CCfD. For an integrated tender, both on-grid and off-grid locations are in principle feasible.

For each of the four options, there are arguments in favour and against, which we list in Table 6-1.

Table 6-1 Advantages and disadvantages of different tender procedures for offshore wind and onshore electrolysis

	Advantages	Disadvantages
Separate tenders	• Low degree of complexity • High degree of competition in each scope	• Possibly negative impacts on existing grid constraints • Risk of mismatching timelines • Growth in electricity demand and supply may be out of pace • May be difficult for electrolyser developer to find a PPA that qualifies with the expected sustainability criteria

[131] In December 2020, 22 EU countries and Norway signed a manifesto paving the way for a cleaner hydrogen value chain and committing to launch 'important projects of common European interest' (IPCEIs) in the hydrogen sector. The signatories committed to jointly design, and eventually launch, IPCEIs and agreed that projects should cover the full value chain — from renewable and low-carbon hydrogen production to hydrogen storage, transmission and distribution, and hydrogen application notably in industrial sectors. Source: **https://ec.europa.eu/growth/industry/strategy/hydrogen/ipceis-hydrogen_en**

Coordinated tenders	• Low degree of complexity • High degree of competition in each scope • Security that the growth in electricity demand (electrolyser) and supply (wind farm) is in keeping	• Due to high degree of competition, tender costs may be high for the bidders • Bids are evaluated and selected in isolation, which may lead to a sub-optimum • Risk of assets not being operated by the same party (i.e. dependency on the realisation of scope by another party, which you have no contractual relationship with) • Revenue risk (for wind developer), as there is no upfront clarity on the offtake • Price risk for electrolyser operator, as there is no upfront clarity on electricity provision
Joint tenders	• Electrolyser can be located in a system-friendly manner • Security that new electricity supply will be met by demand from the electrolyser • Reduced counterparty risk as assets are combined in one tender	• Forces actors into consortia or developers into developing both assets • May reduce competition
Integrated tenders	• Ensures parallel ramp-up of hydrogen supply and demand • Enables a view on where the hydrogen is consumed, e.g. in industry • May reduce costs as the whole chain can find optimisations and share risks	• Complex tender design • Forces actors into consortia • May reduce competition • Successful bidder may be determined by success in finding H_2 offtakers rather than making the most competitive bid

One recurring assessment criterion for allocation mechanisms is the level of competition. For tenders to function properly, competition is fundamentally important. We recommend that the decision for an allocation mechanism should be informed by a market consultation with targeted stakeholder groups. Such market consultation could be embedded in the masterplan process (see section 5.4). Another element we recommend considering in the allocation mechanism is the timeline – different levels of competition can be expected in the hydrogen market at different points in time compared to the offshore wind market. In the near-term future, a low degree of competition can be expected for electrolyser projects as this market is just emerging. Later, around 2030, higher numbers of actors can be expected. This has implications on the choice of the allocation mechanism. For the offshore wind plots that will come available prior to 2030 that could be dedicated to supply electricity for green hydrogen production, clarity on the allocation mechanism is needed soon.

Summarising the assessment from Table 6-1, we conclude the following:

- Separate tenders do not provide for alignment between demand and supply and reduce the ability to alleviate grid constraints.

- Coordinated tenders allow for coordination without being excessively complicated for both the bidders and the government. This coordination is especially important in the beginning to allow for a significant market ramp-up. Coordinated tenders also create strong competition for both tender scopes. The risks for the project developers are higher in this option compared to joint or integrated tenders. More analysis is required on risk mitigation option, e.g. using PPAs.

- Joint tenders are more complex as they require bidders to form consortia or develop both assets themselves. However, at the same time, they reduce risks for the project developers, as both assets are included in one scope.

- Integrated tenders can be quite a strong market intervention. However, they have value in the near-term as they ensure the ramp-up of green hydrogen demand and supply. We recommend against setting up a tender for integrated projects due to the expected low level of competition and the difficulty of comparing project concepts.

As mentioned above, integrated projects are usually tailored to a specific use case. This means that project designs differ significantly between projects, which makes a comparison as part of a tender evaluation difficult. Additionally, the number of integrated projects that would be similar enough to compete in a tender is expected to be low. Implementing a tender is not recommendable at low levels of competition.

An alternative option could be to determine the support for integrated projects not via a tender but instead on a cost basis. Under a funding line, projects could apply for support based on their specific use case and business case. The project initiative would be assessed by an expert committee and eligible costs would be demonstrated according to the requirements set out in the funding line. The aim of the funding line could be to kick-start the hydrogen market on both the demand and supply side and to support specific project proposals covering the entire value chain of electricity supply, green hydrogen production and consumption.

The Coalition Agreement includes a company specific approach (*Maatwerk*) to decarbonise the 10 to 20 largest emitters in the Netherlands. A funding line for integrated projects may be an option to consider.

According to the European State Aid guidelines, exceptions from the requirement to allocate aid and determine the level of aid through a competitive bidding process can be justified where evidence, gathered in a public consultation, is provided that there are insufficient potential bidders to ensure competition. Support will be limited to the minimum needed for carrying out the project, i.e. the level of aid corresponds to the ‘funding gap’ necessary to realise the project. The State Aid guidelines include details on how this funding gap can be determined and proven. Supported projects may be required to disseminate the know-how obtained as a result of the aided project, with the aim of accelerating the roll-out of electrolysers.

Irrespective of the allocation mechanism chosen, coordination is crucial for the roll-out of offshore wind and onshore electrolysis.

6.3 Offshore wind and offshore electrolysis allocation mechanism

Section 4.3 introduced different project configurations for offshore wind and offshore electrolysis. The key differentiation between configurations is whether the electrolyser is integrated into the wind turbine or placed on a centralised platform or island. In section 5.3, we recommended for both project configurations to include the electrolyser scope into the wind farm scope and thus the same allocation mechanism. In line with this recommendation, the analysis presented here holds true for both offshore electrolyser configuration options.

As before in section 6.2, the forthcoming Delegated Act must be considered. For on-grid electrolysers, the electricity must likely be sourced via a PPA from a new (not earlier than 24 months before the electrolyser) and unsupported RES plant. For off-grid electrolysers, the sourced renewable energy resource must likely come into operation in the same year as the electrolyser or later. These requirements pose important questions for offshore wind and offshore electrolysis projects: How can you differentiate between the offshore electrolyser and offshore wind scope to provide support to first but not the latter? How are these considerations different for integrated and centralised electrolysis? These questions should be analysed in detail once the final version of the Delegated Act has been published. The below paragraphs take a more general look at the allocation mechanism, without including these considerations and questions yet.

Large-scale deployment of offshore electrolysis on a gigawatt scale is envisaged to only take place after 2030.[132] Before this, first pilot projects may be realised.[133] This temporal distinction between near- and mid- to long-term also calls for a differentiated view on the allocation mechanism. In this section, we thus differentiate between the near-term and the mid- to long-term.

In the **near-term**, offshore electrolyser projects will likely require support to be economically viable and competitive against fossil-based alternatives such as grey hydrogen. In the allocation mechanism electrolysers, bidders must hence have the option to submit a support bid. Deploying electrolysers offshore is novel, and further insights regarding technical and economic performance of different options is required. The implementation of qualitative award criteria could facilitate an acceleration of progress in in the learning curve for this technology. The cost of electrolysers is expected to fall given economies of scale and learning-by-doing effects. As a result of the support need on the one side and the technological advancements still required on the other side, a focus in the allocation mechanism on both the support bid and the quality of the projects is recommendable in the near-term.

However, such a price and quality combination must be feasible within the regulatory framework. At EU level, the revised Climate, Energy and Environmental Aid Guidelines require a maximum weighing for all other criteria (including qualitative criteria) besides the aid amount of 30%. This means that the support bid must determine at least 70% of the bid evaluation. At Dutch level, the *Kaderbesluit nationale EZK- en LNV-subsidie* states that the

[132] **https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z22374&did=2021D47557**

[133] The government has submitted a proposal for the National Growth Fund for a first demonstration project of hydrogen at sea. This project is several hundred megawatts in size and can possibly be realized before 2030.

criteria and weighing of criteria can be set by Ministerial decree.[134] The *Besluit stimulering duurzame energieproductie en klimaattransitie* further provides the option for innovative wind tenders to combine subsidy level and other award criteria, which can be determined by ministerial decree.[135] The Offshore Wind Act currently provides four options for the allocation of offshore wind sites (see also section 6.1). Three options include other award criteria, one option is focused solely on support bid levels. None of the options entail a combination of support bids with other award criteria. An important point of uncertainty at Dutch level is that – even though there seems to be a general regulatory framework for the combination of award criteria - there is no precedence yet for the combination of support bids with other award criteria for commercial scale offshore wind farms. This uncertainty warrants further discussion and analysis.

In case a combination within the Offshore Wind Act is not deemed feasible, the following alternative options seem feasible:

- **Strong qualitative pre-qualification criteria**: In this option, the qualitative criteria are integrated implicitly in the pre-qualification stage. The qualitative criteria could be phrased as strong pre-qualification criteria that are assessed on a pass/fail basis. This would entail that the quality of projects is not evaluated in detail during the actual bid evaluation, as it has already been assessed in the previous pre-qualification stage. All eligible bids are then evaluated only based on their support bid level.

- **Beauty contest for site**: In this option, the bids for the site under the Offshore Wind Act are assessed based on their quality. The government would award rights to site to a bidder which could then in a second stage apply for support under the *Kaderbesluit*.

- **New instrument**: Alternatively, a new instrument could be designed that allows for a combined assessment. There is a plethora of (hydrogen-specific) qualitative criteria that can be used in combination with price: cost of energy, annual generation amount, efficiency of conversion steps, technical maturity, scalability of the projects, expected environmental impacts, certainty of realisation, system integration benefits, innovation, or envisaged commissioning date.

The choice of option has implications on what allocation mechanism is feasible. The allocation mechanism could consist of either a **competitive tender or a negotiated procedure.**[136] In negotiated procedures, energy producers and the government can negotiate the technical and commercial terms of the project after an initial bidding stage. A negotiated procedure could reduce barriers to participation and risks because project developers and the government can negotiate after the initial bidding stage. A competitive tender is a competitive bidding process for allocating support to renewable energy producers. It is designed to allocate a support contract based solely on the bids submitted by participating bidders according to transparent award rules. There is no negotiation after the bidding concludes. Tenders are market-based, competitive bidding processes to identify the most appropriate projects to whom a defined site is allocated. The basis for a successful tender is competition.

[134] Article 17, **https://wetten.overheid.nl/BWBR0024796/2021-03-09#Hoofdstuk2**

[135] Article 24c, **https://wetten.overheid.nl/BWBR0022735/2020-11-01#Paragraaf3_Sub-paragraaf3.4**

[136] In the previous two sections, we did not discuss these options, as the level of competition generally allows for tenders, which are preferable due to their cost-effectiveness and compliance with the European State Aid guidelines.

In the context of the three options described above, the following seems feasible**:**

- **Strong qualitative pre-qualification criteria**: A competitive tender procedure can be held as there is competition over price.

- **Beauty contest for site**: In this reduced bidder environment, a negotiated procedure could be more feasible than a tender.

- **New instrument**: Both a tender or a negotiated procedure seem feasible.

There are many implications of these options that are still to be assessed and analysed in more detail, such as the notification of the subsidy with the European Commission or the coherence with the forthcoming Delegated Act.

In the **mid- to long-term**, with the ramp-up of the green hydrogen market, supply-side support may be reduced over time in favour of demand-side support. Shifting the support focus away from the supply-side to the demand-side enables a more sector-targeted approach, while alleviating the projects from the restriction of the forthcoming Delegated Act, because support is paid to the offtaker instead. Over time, zero-subsidy bids may become feasible. In that case, a differentiation of bidders only by quality could be feasible. In case of very positive market developments, even a combination of qualitative criteria and a financial bid could become feasible. For these developments, we recommend the use of tenders. Tenders bring certain advantages: Project execution after contract award is usually faster in competitive tenders than in negotiated procurement, due to the absence of a negotiation stage in the tenders. The downside of this is that project developers have less time to find an offtaker for the produced hydrogen. This issue may be mitigated by allowing for a longer realisation period in the tender. Also, a protracted negotiation stage in negotiated procedures can lead to prices that are no longer reflective of market conditions once the implementation starts.

6.4 Summary of recommendations

The following recommendations were made for an offshore wind allocation mechanism:

- We recommend setting up one allocation system which is used for all offshore wind tenders. Within the allocation mechanism, there are three options to choose from.

- For the short-term, where the current market situation makes a continuation of zero-subsidy bids likely, option 1 (qualitative criteria & capped financial bid) or option 2 (uncapped financial bid) could be applied. Option 2 may put greater strain on the business case. Careful consideration of the market and supply chain conditions is advised before choosing between these options. For the longer-term, there are larger uncertainties with a view to the development of electricity wholesale market prices. If prices develop favourably for the offshore wind project developers, we recommend to option 2 (uncapped financial bid). If prices are not developing favourably for the offshore wind project developers, we recommend opting for option 3 (backstop in combination with qualitative criteria and capped financial bid in case of multiple zero-subsidy bids).

- We recommend that market consultations should be maintained for technical and economic insights.

- Currently, tender decisions are taken relatively late. We recommend considering running tender preparations in parallel rather than in sequence. The continued market consultations would still enable a direct consideration of the market status.

- In case of option 1 and 3, we recommend that the government should either be largely continuous in its themes of qualitative criteria included (i.e. continue focusing on innovation) or communicate changes early on so that the market participants can react.

- We recommend that once an element can be considered an industry standard (e.g. a certain environmental mitigation measure), it should be removed from the award criteria and included as a pre-qualification requirement (pass/fail criterion).

- For options 1 and 3, we recommend that the financial bid should be designed as a lump sum payment rather than a production-based payment by the developer for every MWh produced.

- For options 1 and 3, we recommend considering that the financial bid cap could be increased over time if market parameters change. The decision could be based on previous market consultation to estimate how much market parties are willing and able to pay.

- For option 2, we recommend considering using dynamic tenders to determine the winner.

- For option 2, we recommend that the assessment of expected wholesale market prices and the resulting ability to pay should go hand in hand with market consultation.

- For option 3, we recommend verifying under which conditions this option should be chosen – i.e. is a previously failed subsidy-exclusive tender round a necessity or not.

The following recommendations were made for an offshore wind and onshore electrolysis allocation mechanism:

- We recommend further discussion and analysis (e.g. on the impact of the designs on the cost of hydrogen production or on the duration of pre-development) before the final selection of a or more allocation mechanism(s).

- We recommend that the decision for an allocation mechanism should be informed by a market consultation with targeted stakeholder groups.

- We recommend against setting up a tender for integrated projects due to the expected low level of competition. Instead, we recommend setting up a dedicated short-term funding line, which provides support to projects on a cost basis.

The following recommendations were made for an offshore wind and offshore electrolysis allocation mechanism:

- We recommend differentiating between the short-term and the mid- to long-term.

- In the short-term, we recommend the use of a multi-criteria assessment.

- In the mid- to long-term, we recommend reducing supply-side support in favour of only demand-side support or quotas.

- In case, zero-subsidy bids become feasible, we recommend a differentiation of bidders only by quality. In case of very positive market developments, even a combination of qualitative criteria and a financial bid could become feasible. For these developments, we recommend the use of tenders.

7. Tender product & site definition

This chapter describes the items that could be parts of a tender (section 7.1) and possible changes to future site definitions (section 7.2). Finally, in section 7.3 we consider whether realisation periods (i.e. the period between tender award and the deadline for the wind farm to become operational) and permit durations require reconsideration.

7.1 Tender product

The tender product defines what items are provided to a successful bidder in a tender procedure. This section makes explicit what the tender product could entail considering decisions regarding the governance model and the allocation mechanism. It is a supplement to chapters 5 and 6, intended to provide further clarity.

7.1.1 Offshore wind

For electrically connected offshore wind farms which do not include electrolysis, we consider the following items as part of the tender product, mostly analogous to the current roll-out (except for the possible inclusion of a backstop):

1. Exclusive rights to construct and operate the wind turbines and their associated balance of plant[137] within the site boundaries
2. Permits to construct and operate the wind farm
3. Access to offshore transmission infrastructure
4. In case subsidy-free offshore wind roll-out fails, grant (*beschikking*) of a support scheme ("Wind farm support scheme backstop"), in accordance with section 6.1.

The following Table 7-1 sets out the arguments for and against including these four items in the tender package. The baseline is a TSO-led model. The counter-factual would be a tender for the rights to build the wind farm only. In this case, the permitting process and the realisation of the offshore infrastructure would be the task of the developer, i.e. a developer-led governance model.

Table 7-1 Assessment of items in the tender product for offshore wind

Item	Pros	Cons
Rights to build the wind farm	• This is the main item on tender, removing it is not an option	N/A

[137] The balance of plant includes the foundations and inter-array cables.

Permits	• Reduces timeline from tender to operations substantially • De-risks the development by certainty of permit • Improves the investment climate of the Dutch offshore wind market compared to countries where this is the developer's responsibility • Enables greater coordination between wind farms and other users of the sea	• Requires governmental human resources with the right level of expertise • Requires pre-defining a design envelope • Restricts design options for developers
Access to offshore infrastructure	• Reduces timeline from tender to operations substantially (design and contracting can be done ahead of tender) • Enables standardisation and through it cost reduction • Allows for the integrated design of onshore and offshore grids • De-risks developers from transmission assets issue, in case a compensation scheme is used	• Limits optimisation between wind farm and transmission asset design • Restricts design options for developers • Introduces liabilities to a TSO and by proxy to society • Pace of roll-out could become dependent on the TSOs ability to deliver new transmission assets
Support (if subsidy-free fails)	• De-risks developers compared to separating rights to build and support schemes in two competitive processes (e.g. UK system) • Reduces timeline from tender to operations substantially (financial investment decision is not held up by separate subsidy allocation round)	• Support scheme allocation is tied to site allocation, which limits competition *between* technologies

Based on the assessment, we recommend for tenders for future electrically connected wind farms to retain all four items within the tender product. This will:

- Enable full coordination between onshore and offshore electricity grid planning and realisation;
- Create a strong investment climate for investments in the Dutch offshore wind market;
- Enable short realisation times, which are critical considering the pace of decarbonisation regarding to meet targets; and
- De-risk developers, which supports a lower levelized cost of energy (and by extension, supports subsidy free wind farms).

7.1.2 Offshore wind and onshore electrolysis

In section 5.3, we highlighted that it is challenging for the government to pre-develop an onshore site for electrolysis. We further explored four tender models with varying degree coordination: (1) separate tenders, (2) coordinated tenders, (3) joint tenders, (4) integrated tenders.

For each of these models, we recommend that the tender product for the offshore wind scope includes:

- Exclusive rights to construct and operate the wind farm (wind turbines, foundations, cables) ;
- Permits to construct and operate the wind farm; and
- In case of an onshore on-grid electrolyser, access to offshore transmission infrastructure. In case of an off-grid electrolyser, one could argue that the developer should be responsible for realising the offshore transmission infrastructure.

For the onshore electrolyser scope, the following items are considered, but not necessarily included in the tender product:

- Exclusive rights to build the electrolyser at a specific location;
- Permits for the electrolyser;
- Onshore connection between electrolyser and sub-station (assuming an on-grid electrolyser);
- Support for the production of hydrogen;
- Support for decarbonisation (hydrogen offtake).

The differences in the tender product between the tender types are highlighted in Table 7-2 in **bold**. Note that in terms of tender product, there is no difference between the separate and coordinated tender.

Table 7-2 Differences in the tender product between the tender types

Item	Separate tenders	Coordinated tenders	Joint tender	Integrated tender
Rights to build the wind farm	Included (WOZ tender)	Included (WOZ tender)	Included	Included
Permits (wind farm)	Included (WOZ tender)	Included (WOZ tender)	Included	Included
Access to offshore infrastructure	Included (WOZ tender)	Included (WOZ tender)	Included	Included
Wind farm support scheme backstop	**Included if applicable (WOZ tender)**	**Not included**	**Not included**	**Not included**
Right to build the electrolyser	Not included	Not included	Not included	Not included

Permits electrolyser	Not included	Not included	Not included	Not included
Onshore connection between electrolyser and substation	Not included	Not included	Not included	Not included
Support scheme for produced hydrogen	**Included (CAPEX support, sliding feed-in premium)**	**Included (CAPEX support, sliding feed-in premium)**	**Included (CAPEX support, sliding feed-in premium)**	**Not included**
Support scheme for decarbonisation	**Not included**	**Not included**	**Not included**	**Included**

Offshore wind scope: The tender product is similar to that of an "offshore wind only" tender. In case of joint and integrated tenders, the offshore wind scope is combined with the electrolyser scope in a single tender.

Wind farm support backstop: In case of a coordinated tender, a joint tender or integrated tender, it is expected that a support backstop for the wind farm cannot be part of the tender product. For each of these tender types, the offshore wind farm would provide electricity to the onshore electrolyser. The Delegated Act on sustainability criteria may disallow the contracted renewable electricity generator receiving support, as a criterion to qualify the produced hydrogen as an RFNBO. Regardless of the exact content of the future Delegated Act, we recommend avoiding stacking subsidies, thus only providing support to the produced hydrogen in case of joint and integrated tenders.

Electrolyser onshore land rights & permit: There is a challenge in providing a similar type of one-stop-shop package for the electrolyser scope, compared to the offshore wind scope. Land ownership is spread between governmental agencies (such as Rijksvastgoedbedrijf, Bureau Beheer Landbouwgronden, provinces, waterschappen, municipalities) and private owners. Providing exclusive rights and permits for onshore electrolysers involves many more stakeholders than offshore. As set out in section 5.3, we recommend that the winning electrolyser bidder is made responsible to obtain land rights and permits.[138] As a consequence, it is not part of the tender product. Electrolysis benefits from scale advantages, and industrial offtakers typically require significant volumes (thus requiring large scale electrolysis to meet demand). It should be noted that current footprint of a gigawatt scale electrolyser is in the order of 10 hectares[139]. This could mean that in practice the number of suitable locations is limited. This could pose a risk of limited competition.

Onshore connection between electrolyser and substation: For similar reasoning as the land rights and permits for onshore electrolysers, we recommend making the developer responsible for the connection from the electrolyser to the onshore high voltage substation owned by TenneT. However, considering the large electrolyser capacities expected, it may be sensible for TenneT to realise new onshore substations in anticipation of the realisation of onshore electrolysers.

[138] Note, in this section we also describe the role the government could take in coordination of spatial planning processes to enable effective permitting procedures
[139] **https://ispt.eu/projects/hydrohub-gigawatt/**

Support scheme for hydrogen production: For the separate electrolysis tender, the coordinated tenders and joint tenders, we recommend providing a subsidy for the production of hydrogen, as further detailed in section 8.2.2.

Support scheme for decarbonisation: For integrated tenders, we recommend providing a subsidy for the actual decarbonisation of the final offtaker. A similar rationale applies as above, to only provide support to one actor to avoid stacking subsidies. This requires a demand-side support instrument, such as a carbon contract for difference (CCfD). Section 5.5 includes further examples and considerations on demand-side instruments.

7.1.3 Offshore wind and offshore electrolysis

In case of offshore electrolysis, we distinguish between integrated and centralised electrolysis.

In case of **integrated electrolysis**, the tender product can be analogous to the tender product of electrically connected offshore wind farms (in a separate tender): the tender product includes the rights and permits to build the wind farm (and its balance of plant), access to the offshore (hydrogen) infrastructure, and a support scheme in case subsidy-free realisation is not possible.

In case of **centralised electrolysis**, electrolysers are situated on an island or platform. The tender product may either include or exclude the rights and permits to realise and operate electrolysers. This should follow the decision on the governance model (roles & responsibilities) of offshore electrolysis as discussed in section 5.3. In case the electrolyser is part of the wind developer’s scope, and a shared substructure is realised to host electrolysers of multiple wind farms, we recommend including the rights and permits to realise offshore electrolysis on the centralised location in the tender. A separate bilateral agreement with the owner/operator of the substructure will be needed, this can be negotiated (based on a clear tariffs and conditions known at the time of the tender) after the tender award. In case there is no shared substructure, the wind developer can realise its own platform or substructure to host electrolysers.

7.2 Site definition

As a consequence of the one-stop-shop mechanism for offshore wind farm developments, and through inclusion of the provision of permits in the tender product, the offshore wind farm sites need to be defined by the government. This means that the design bandwidth needs to be sufficiently clear and not overly broad to enable the Environmental Impact Assessment. Some elements of the design may, however, differ compared to the design bandwidth provided to wind farm developers thus far. In this section, we discuss the main characteristics and possible changes to the definition of sites.

Note that the analyses in this report are focussed on the roll-out of offshore wind in the context of integration challenges in the energy system. Integration of offshore wind in the North Sea (spatial planning, taking into account the interests of multiple users of the North Sea, ecological impact) is of vital importance as well but not part of the scope of this report.

7.2.1 Site definition for electrically connected wind farms

Wind farm capacity: The capacity of wind farm sites under the Routekaart 2030 varies:

- from Borssele I to Hollandse Kust (noord) ~350 MW[140] per site (connected using AC),
- for Hollandse Kust (west) and Ten Noorden van de Waddeneilanden ~700 MW per site (AC), and
- for IJmuiden Ver 1 GW per site (connected using DC).

These capacities are derived from the capacities of the offshore transmission assets developed by TenneT (approximately 700 MW for the AC connections and 2 GW for the DC connections). The optimal size (in terms of capacity) of wind farms is a balance between economies of scale, the cost of offshore infrastructure, the threshold to invest and resulting level of competition, and the risk of non-realisation of a wind farm compromising meeting the emission targets.

The 2 GW HVDC standardised design by TenneT enables the connection of 2 GW wind farm capacity. In the future, a 2 GW connection may remain a maximum, as the failure of a single connection must not result in an interruption of electricity delivery (n-1 norm, or "*enkelvoudige storingsreserve*"). While ultra-high voltage onshore transmission systems that enable larger capacities are being realised globally, onshore grid stability may continue to restrict the maximum capacity of a single offshore connection. It would be possible to tender a site that includes multiple HVDC connections, enabling sites larger than 2 GW. A development that includes offshore electrolysis enables larger transmission capacities and thus larger wind farm sites as well, due to the larger transmission capacity of hydrogen pipelines.

A larger capacity of the wind farm sites may increase the threshold to invest and reduce the level of competition. A continued increase in capacity may result in some developers reaching their capital limits, thereby shrinking the playing field. However, no clear relation between wind farm capacity and diminishing interest from the market has been observed in practice. Illustratively, the UK Round 4 offshore wind site leasing round has seen high financial bids from various competitors for concessions up to 1.5 GW.

Considering the progress towards decarbonisation targets, a limitation of the capacity of wind farm sites may be a mitigative measure that reduces the risk of failing to meet targets in case a wind farm development project is unable to reach the operational phase. This should be balanced with the increase in executive burden for the tendering authority of running more tenders for smaller sites.

We recommend awaiting the Hollandse Kust (west) tender bids to decide between a future wind farm capacity of 1 or 2 GW for the DC sites. The market will provide insights through this parallel tender of two ~700 MW sites. If it is apparent that the market is ready and willing to commit and realise 1.4 GW sites in 2022 (i.e. bidding on both sites unconditionally), it is only a small step to realise 2 GW later in the roll-out. In order to mitigate the risk of meeting decarbonisation targets and more broadly security of supply, and to avoid pushing out less capital-intensive players out of the market, we recommend caution to go beyond allocating such a large capacity in single tender rounds in the short term. In the longer term, technological and market developments may warrant reconsideration of a further increase in scale.

Density: The density of the wind farm sites is typically expressed in Watt per square meter (W/m^2). The optimum density is determined by the balance between available space in consideration with other uses, wake losses, fixed costs, and costs for electrical infrastructure. Wind turbine design imposes a limit to the density, or turbine spacing, that

[140] Actual wind farm sites capacities vary, depending on the site design of the developer.

must be respected. The *Beleidsnota Noordzee 2016-2021* assumed a density of 6 W/m^2, while the *Ontwerp Programma Noordzee* assumes a density of 10 W/m^2, a 40% increase.

In a European context, a density of 10 W/m^2 is at the high end of wind farms developed up to 2018. Particularly Belgium and Germany have wind farms with greater density, and Belgium is the only country which had an average above 10 W/m^2, with 12 W/m^2. As a more recent comparison, the UK Round 4 sites range between 3 to 4 W/m^2.

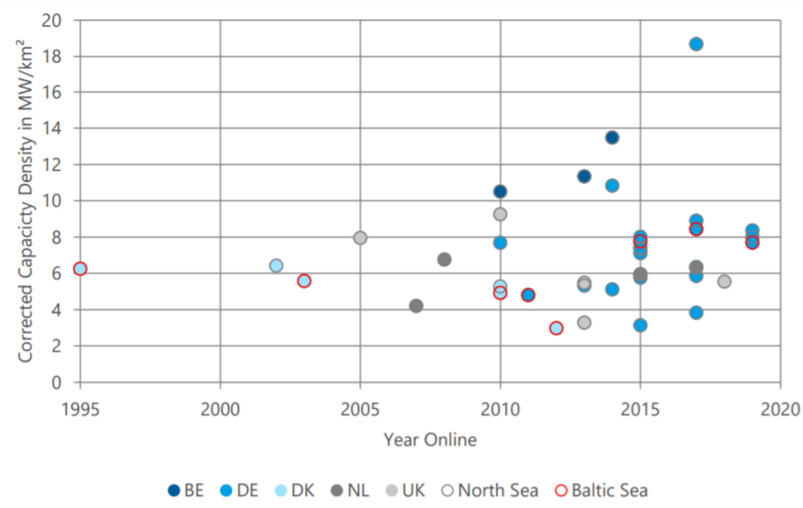

Figure 7-1: Overview of capacity densities of wind farms (Deutsche WindGuard)[141]

For electrically connected wind farms, we have not identified reasons to currently deviate from the 10 W/m^2 density. However, we recommend to regularly engage with the wind industry to understand whether technical developments (e.g. advanced wake reducing control strategies) or changing economics warrant an increase in density. Any technical and economic interests need to be weighed against environmental impact and the interests of other users.

Wind turbine dimensions: The site decision sets out (1) the minimum hub height, (2) the minimum and maximum blade tip height, and (3) the maximum total swept surface of the rotor. These factors are mainly set by environmental impact (particularly mitigating casualties of bats and birds) and aviation regulation. Academia, the wind industry and environmental agencies are developing methodologies to mitigate impact on bats and birds, such as through migration prediction models and the use of radar technologies. The Universiteit van Amsterdam is developing a model specifically for the Netherlands, and a start / stop protocol based on this model should be implemented in 2023 for new wind farms. Future site definitions should be informed of the latest insights and mitigative measures. As wind turbines continue to increase in capacity and size, interest in increasing the maximum blade tip height will grow.

Wind turbine capacity and amount: The site decision sets out the minimum capacity per wind turbine and maximum amount of wind turbines that may be installed. The current pace of introducing new and larger (capacity, rotor diameter) wind turbines is high, and has contributed to the decrease in the cost of offshore wind energy. The capacity of wind turbines is expected to keep growing. Capacity limits that were considered hard (or uneconomical) to surpass in the past have been passed since. In setting a minimum wind turbine capacity, we recommend considering both ecological impact (a larger capacity results in fewer turbines, which reduces ecological impact), as well as providing the industry

[141] Deutsche WindGuard, Capacity Densities of European Offshore Wind Farms, 2018

room to optimise. An increase in minimum capacity should be tested with the market through consultation, to ensure it does not result in a reduction in competition. Finally, through a fixed wind farm capacity and minimum wind turbine capacity, the maximum number of turbines is defined a priori.

7.2.2 Site definition for wind farms including offshore electrolysis

For some of the site definition elements, the inclusion of offshore electrolysis may warrant a different approach.

Wind farm capacity: In case of offshore electrolysis, there is an argument for greater flexibility in the capacity of wind farm sites. The hydrogen infrastructure cost is much less sensitive to the capacity of hydrogen, so it can be attractive to provide wind farm developers a greater bandwidth to optimize the wind capacity within a site. In the same way as currently done in the Site Decisions, a minimum wind farm capacity can be set to ensure the seabed (and possibly a shared offshore infrastructure) is used efficiently.

Density and wind turbine capacity: In case of integrated offshore electrolysis, wind turbines will be redesigned to achieve a new economic optimum between rotor diameter and capacity. The optimum turbine capacity compared to the rotor diameter will increase. Even when keeping the spacing between turbines the same, this would directly increase power density (W/m^2 seabed). Wind turbine manufacturers envisage a possible increase greater than 30%. Wind farm developers may also wish to pursue a smaller spacing between turbines in case of integrated offshore electrolysis and install a greater number of wind turbines (see previous paragraph). This would increase the total rotor surface area within the wind site, which would increase the ecological impact. Increasing the total rotor surface area requires assessment of the cumulative impact of the planned roll-out of offshore wind, and how much ecological “room” can be provided to a single development.

In case of centralised offshore electrolysis and onshore electrolysis, we do not envisage substantial differences in the optimum density compared to a radially electrically connected concept.

Ratio between hydrogen and electricity transmission: In case of centralised offshore electrolysis, a hybrid infrastructure that allows transmission of both hydrogen and electricity could provide additional (net) benefits, compared hydrogen only. The optimum hybrid electrical capacity depends on the balance between supply and demand in the electricity and future hydrogen markets and requires price modelling. In the study Systeemintegratie wind op zee 2030-2040, we conducted an approximation of the net benefit of adding a hybrid electrical connection to a centralised electrolysis island. The main take-away was that there is no static optimum ratio, as the value is driven by supply and demand.[142]

Wind turbine dimensions follow the same reasoning as in case of radially electrically connected wind farms.

Technology considerations in the site definition

As discussed above, some factors may change depending on the type of offshore electrolysis. For an optimal use of the wind farm area, this might imply that a site definition is not technology neutral (i.e. requires a choice between integrated or centralised electrolysis). In contrast, from the perspective of granting the market room to select the optimum technology, a technology neutral site definition is preferrable. In some cases, the infrastructure configuration will predetermine the possible technologies, resolving the

[142] **https://windenergie-nieuws.nl/22/rvo-publiceert-studie-systeemintegratie-wind-op-zee-2030-2040/**

dilemma. In general, we recommend tracking technical and economic developments of offshore electrolysis, to assess whether a suboptimal design bandwidth is warranted to achieve technology neutrality.

7.3 Realisation period and permit duration

7.3.1 Realisation period

The realisation period specifies the time during which projects need to be commissioned, i.e. the validity of the award. If the realisation period is exceeded, i.e. a project fails to be completed in time, penalties can be imposed. Realisation periods are relevant for both site and support allocation. Realisation periods need to reflect realistic project delivery periods while avoiding lengthy realisation periods that would encourage speculative behaviour and thus increase the risks that projects are not realised. For offshore wind, there is currently under SDE++ an established realisation period of five years with monthly penalties for delayed delivery. There are three developments that may warrant a longer realisation period:

1. The importance of securing an offtake agreement may increase, as market prices become more volatile. The realisation period should allow for this.

2. The commissioning process for HVDC assets is more complicated than HVAC assets. The commissioning of the HVDC assets have implications for the commissioning of the wind farm, and may result in a longer commissioning duration.

3. Greater strains on the supply chain, as internationally the offshore wind roll-out increases in pace. This could result in production slots being fully booked to the point that a five year realisation period is no longer possible.

A high realisation pace is required in future roll-out, thus extending the current realisation period should only be done if it is truly necessary.

For offshore wind and hydrogen projects, realisation periods are more uncertain as large-scale electrolyser projects are yet to be realised. Estimates that we have gathered from industry differ, but developers of large-scale projects indicate that the realisation period could be up to 8 years (development & permitting 2-3 years, financial investment decision to start operations 5 years). Realisation periods should be aligned and coordinated with the required infrastructure development timelines. Allocation mechanisms and tender types could impact the total realisation period (e.g. by starting wind and electrolysis development at the same time, versus separating the start dates). For offshore wind and hydrogen projects, we recommend establishing an expert group with representatives from the offshore wind industry, the hydrogen industry, and the infrastructure developers which could inform EZK and RVO in setting a realisation period which is achievable yet tight enough to ensure project realisation. Such an expert group could also investigate opportunities to accelerate timelines.

7.3.2 Permit duration

Permit durations should follow developments in the operational lifetime of wind farms. The Offshore Wind Energy Act (Wet Windenergie op Zee) stipulates that the permit duration should take into consideration the specific area and the expected lifetime of the wind farm. It also sets an upper limit of 40 years. Assuming a total duration for construction and decommissioning of 5 years, this results in a total operational lifetime maximum of 35 years.

Some developers have indicated that 35 years operational lifetime is already feasible and see possibilities to extend this further. Consultation with industry regarding the Hollandse

Kust (west) tender concluded the current lifetime is approximately 30 years. We recommend continuing dialogue with the industry to have the latest insights when setting permit durations. If the sector is indeed able to exceed an operational lifetime of 35 years, the current permit duration maximum of 40 years may be reconsidered. This should be weighed against possible downsides of providing a longer claim to a scarce area, such as e.g. technological advancements that would enable providing greater societal benefits from the same area.

In general, more clarity at time of award on the permit duration, in contrast to offering uncertain permit extension options, is preferable, as this provides developers the opportunity to make provisions in their design and asset management approach at an early stage. This increases the possibilities to realise longer operational lifetimes and could improve cost effectiveness.

Permit durations for electrolysers should similarly take the expected lifetime and construction and decommissioning durations into consideration. Stack lifetimes are expected to increase[143], and some developers envisage carrying out stack replacements over the lifetime of the electrolysis plant[144]

7.4 Summary of recommendations

Throughout the chapter, the following recommendations were made.

Regarding the tender product of different types of projects:

- We recommend for tenders for future electrically connected wind farms (i.e. which are tendered separately from electrolysis) to retain all four items within the tender product (exclusive rights to construct and operate, permits, access to offshore transmission infrastructure, and in case subsidy-free offshore wind roll-out fails, grant of a support scheme)

- For each of the onshore electrolysis models, we recommend that the tender product for the offshore wind scope includes the exclusive rights to construct and operate the wind turbines and their balance of plant, the wind farm permits and in case of an onshore on-grid electrolyser, access to offshore transmission infrastructure. In case of an off-grid electrolyser, one could argue that the developer should be responsible for realising the offshore transmission infrastructure.

- For coordinated, joint and integrated tenders, we recommend to not include a support scheme (backstop) for the offshore wind assets, for compliance with expected sustainability criteria in the Delegated Act and in order to avoid stacking subsidies.

- We recommend that the winning onshore electrolyser bidder is made responsible to obtain land rights and permits, noting that if possible to include land rights and permits in the tender product this may decrease the lead time.

- For similar reasoning as the land rights and permits for onshore electrolysers, we recommend making the developer responsible for the connection from the electrolyser to the onshore high voltage substation owned by TenneT.

[143] **https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf**

[144] **https://pv-magazine-usa.com/2020/03/26/electrolyzer-overview-lowering-the-cost-of-hydrogen-and-distributing-its-productionhydrogen-industry-overview-lowering-the-cost-and-distributing-production/**

- For the joint tenders, we recommend providing a subsidy for the production of hydrogen.

- For integrated tenders, we recommend providing a subsidy for the actual decarbonisation of the final offtaker.

- Based on our recommendation to include the ownership and operational responsibility to the wind farm developer, we recommend to also include the rights and permits to realise offshore electrolysis on the centralised location in the tender.

Regarding the site definition of future offshore wind farms:

- We recommend awaiting the Hollandse Kust (west) tender bids to decide between a future wind farm capacity of 1 or 2 GW for the DC sites.

- For electrically connected wind farms, we have not identified reasons to currently deviate from the 10 W/m2 density. However, we recommend to regularly engage with the wind industry to understand whether technical developments (e.g. advanced wake reducing control strategies) or changing economics warrant an increase in density.

- In setting a minimum wind turbine capacity, we recommend considering both ecological impact (a larger capacity results in fewer turbines, which reduces ecological impact), as well as providing the industry room to optimise.

- In case of offshore electrolysis, more flexibility may be provided in terms of wind farm density and capacity.

- In case of offshore electrolysis, the optimal site definition may not be technology neutral. We however recommend leaving the decision up to the market, unless the infrastructure decision, or market developments clearly show integrated or centralised electrolysis is preferable.

Regarding the realisation periods and permit durations for projects:

- We currently do not recommend diverging from the current realisation period for offshore wind, but to reassess for HVDC projects and in case of more challenging market conditions.

- For offshore wind and hydrogen projects, we recommend establishing an expert group with representatives from the offshore wind industry, the hydrogen industry, and the infrastructure developers which could inform EZK and RVO in setting a realisation period which is achievable yet tight enough to ensure project realisation.

- We recommend continuing dialogue with the industry to have the latest insights when setting permit durations, but as a general principle to follow the technical lifetime of the assets.

8. Support policy instruments

Policy instruments are the techniques used by the government to promote certain policies to achieve a predefined set of goals. In the context of this study, the goal is the successful roll-out of offshore wind until 2040. The previous chapters of part 2 had looked at framework elements such as governance that need to be in place for the continued offshore wind roll-out. This chapter focuses more narrowly on the support policy instruments available.

Before focusing on the instruments, the changes towards 2040 need to be considered. Up to 2040, the following **risks** may materialise:

- Capture prices[145] of offshore wind may be structurally lower than the levelized cost of electricity when approaching a system with >90% of variable RES in the mix and low operational costs (OPEX).

- Other revenue streams may not materialise or are of lower value than expected (e.g. ancillary services).

- There may be increasing hours where total renewables supply exceeds total demand, resulting in zero or negative prices and high volatility.

- Installations further from shore might increase costs due to, amongst others, logistical particularities.

- There may be insufficient onshore grid capacity or demand for the produced electricity.

- Wholesale market electricity prices may be fluctuating increasingly more, leading to higher uncertainty regarding the market value of the offshore wind assets.

- Other (fossil) generation assets may not be phased out at the same speed as offshore wind capacity is phased in, and demand will not adapt quickly enough; for a transition period, the market thus may not be in equilibrium.

- Market arrangements may be adapted (e.g. by implementing offshore bidding zones), impacting the revenues and hence the business case.

- A future high-RES electricity market likely leads to price depression at times when there is a lot of wind and solar radiation, driving capture prices down (cannibalization effect), leading to revenue uncertainty.

All these risks are related to the business case challenge (see chapter 2). This chapter is hence also written very much from that perspective. At the beginning of the report, we had also identified the infrastructure challenge and the integration and interface challenge. Linkages to these two challenges are pointed out at the relevant sections.

Currently, zero bids are possible and can continue to be possible in the future. The next section, section 8.1, describes possible policy instruments supporting a continuation of a **subsidy-free offshore wind roll-out**. However, given the above identified future challenges and other uncertainties, there may also be circumstances in which the subsidy-free approach is no longer feasible. A possible solution is the **implementation of policy instruments** to ensure future investments into offshore wind. Options for the support of

[145] The term “capture price” relates to the actual electricity price achieved by a generator in the market, and it’s compared against the wholesale price.

offshore wind can be found in section 8.2.1. Section 8.2.2 broadens the scope of support and examines the joint tendering of offshore wind and hydrogen.

8.1 Continued subsidy-free roll-out

The roll-out of offshore wind has been a success story thus far. Starting in 2016, it resulted in a steady pace of successful tenders, with rapid cost reductions resulting in subsidy-free projects in the space of two years. Through the decline (and in some cases now absence) of subsidies, revenues of wind farms are increasingly or already fully dependent on the market to maintain a viable business case. Investments in wind farms which have such merchant risk exposure, require a long-term view on a well-functioning market. Wholesale electricity prices are driven by supply and demand. When creation of new supply of renewable energy sources outpaces the demand, electricity wholesale market prices will fall. Creating demand through electrification of current energy use or creating new demand, either directly or indirectly (e.g. electrolysis), can support the stabilization of electricity prices. One element that is particularly relevant in this context is that the demand needs to be flexible to match varying electricity generation from offshore wind and other renewable sources. Possible policy instruments for the demand-side include quotas, CAPEX support for retrofitting processes, CO_2 pricing, CCfDs and the phase-out of fossil energy. Also, the phase-out of indirect subsidies can create clearer market signals.

Today, the market for green hydrogen is small. This is expected to change rapidly in the near future. The proposed 50% RFNBO quota by 2030 included in the Fit for 55 package creates a significant pull on the demand side. Large volumes of renewable electricity are required for the production of green hydrogen. This demand incentive may be strong enough to stabilize market prices and hence ensure revenues for offshore wind project developers. In addition, the European Emissions Trading Scheme (EU ETS) creates pressure on industry to decarbonize, e.g. through the electrification of processes.

Throughout the working group meetings, project developers have underlined the importance of ensuring demand rather than supporting supply. The overwhelming sentiment is that solutions should not be sought in the cost of wind, but in the coordination of supply and demand. This sentiment may appear counterintuitive. Why would project developers not want support money? The answer lies in the effects of a subsidy on the market. Most project developers currently in the market have assets in their portfolio that were built on a merchant basis, hence without support payments. In case the subsidy-free approach fails, and support is reintroduced, the portfolio may be extended to supported assets. **While the payment of support helps to secure the revenues for the subsidized asset, it will at the same time lower the revenues to be earned for the no-subsidized assets**. This is because with the help of the support scheme, additional RES capacity is being pushed into the market, thereby lowering market prices, which the market itself would not have warranted if the market equilibrium of supply and demand was the leading consideration.

The government's focus should thus be on ensuring that the framework conditions for a continued subsidy-free roll-out are in place rather than preparing a support scheme. This focus on a market-driven, subsidy-free offshore wind roll-out is attractive for many reasons:

- It does not require public funds for the support of the wind farms, which can then be used for other purposes.
- It does not disturb the market and price formation therein.
- The market allows for a better balance between demand and supply than any policy-driven supply-push into the market

- According to the leaked Delegated Act, new and unsupported renewable energy will likely be required to produce green hydrogen.

8.1.1 Power Purchase Agreements and other policies supporting market-based revenues

Power Purchase Agreements (PPAs) are not a policy instrument per se, but rather a market tool (i.e. a contract between two market parties). Here, we are focusing on the policy/regulatory framing of direct PPAs between an electricity producer and a consumer. PPAs in the context of the Delegated Act and green hydrogen production are touched upon in section 6.2.

The rationale for concluding PPAs differs for the parties. For **producers,** PPAs can provide revenue certainty and reduce risks. Offtakers, on the other hand, sign PPAs to comply with **corporate obligations for sustainability**. They also highly value the associated positive influence on the company's image. These benefits are especially important for companies which produce final consumer products. Another benefit may be the long-term price commitment under a PPA, which can **protect involved parties from rising electricity prices**. This is especially important for **electrolysers** for whom the electricity price is the main cost element in the production of green H_2.[146] Hydrogen producers thus have a large interest to hedge against high prices, however do not want to be committed to a long-term agreement when prices drop. PPAs are generally more attractive to large industrial offtakers than to small and medium-sized enterprises (SMEs), which often perceive PPAs as too complex.[147]

For PPAs, we see a few **developments and challenges occurring between now and 2040**:

- PPAs are a means for electricity producers to ensure long-term electricity offtake. The interest for and reliance on direct PPAs for hedging will continue to grow due to uncertainty of future market prices.

- The (potential) offtake actor landscape may become more diverse, as increasingly more applications in the Netherlands electrify.

- PPAs are receiving more recognition in the EU, which is already shown by the inclusion in the proposal for a revision of the RED II.

- In the future, the sustainability criteria for green hydrogen production may become a driving factor for direct RES PPA market development (see also section 6.2).

There are two risks that PPAs face, which may reduce their feasibility as a hedging instrument in the future. Firstly, there is a **credit (or default) risk**. Offtakers which have a high potential for electrification (such as e.g. ThyssenKrupp, see Figure) may logically be a great PPA partner, but may have a bad credit rating, making them less eligible as offtakers.

[146] One particular element to add here is that the need for a PPA is highly dependent on the location of the electrolyser. If the electrolyser is integrated in the turbine, there is no need for a PPA, as the electricity and the hydrogen production are within the same entity. If the electrolyser is offshore (e.g. on an artificial island), it is likely that the electrolyser is operated by the same consortium which operates the wind farm. In that case the electricity delivery is likely also defined between the consortium parties. If the electrolyser is onshore, the need for a PPA is highest out of the three options. Depending on the intended hours of operation, an electrolyser may require more than one PPA.

[147] Assessment based on information received in a bilateral interview.

Secondly, there is an **arbitration risk**, which may also occur with AA offtakers[148]. Most long-term contracts contain clauses for when there is a material change in circumstances (such as power prices increasing rapidly with Covid). This would allow parties to end the contract early, making them again vulnerable to market revenue uncertainties.

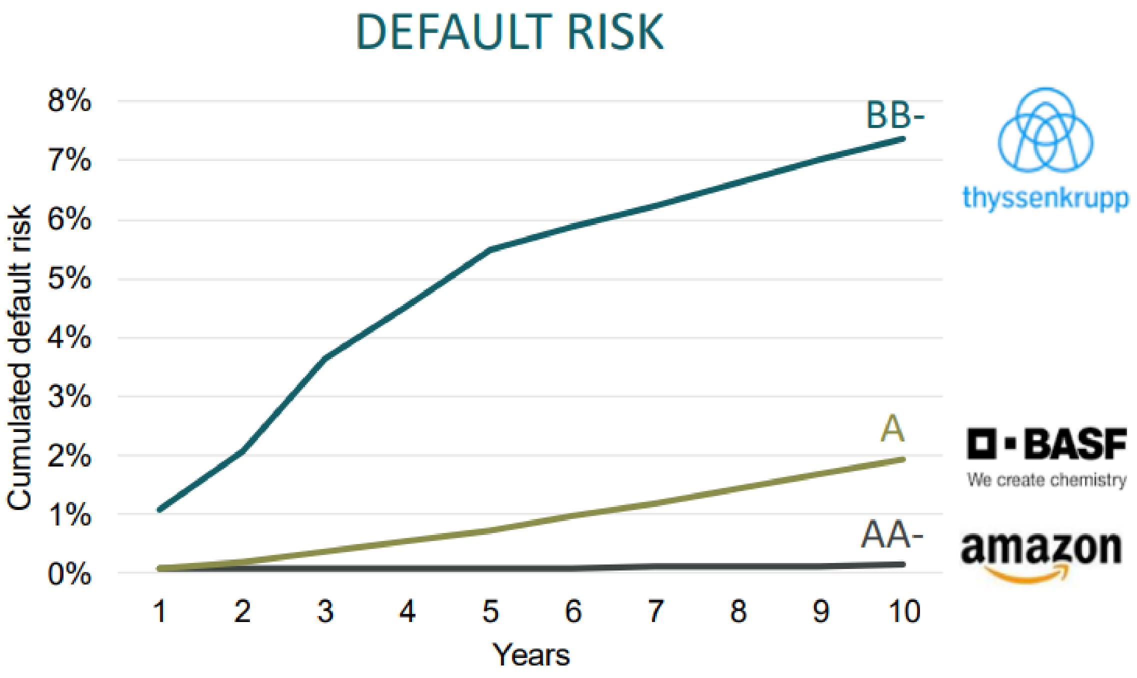

Figure 8-1 Credit risk affecting PPAs[149]

The proposal for a revision of the RED II makes direct reference to PPAs. Concretely, the text says that "*Member States shall assess the regulatory and administrative barriers to long-term renewables power purchase agreements, and shall remove unjustified barriers to, and promote the uptake of, such agreements, including by exploring how to reduce the financial risks associated with them, in particular by using* ***credit guarantees****. Member States shall ensure that those agreements are not subject to disproportionate or discriminatory procedures or charges, and that any associated guarantees of origin can be transferred to the buyer of the renewable energy under the renewable power purchase agreement.*" Public credit guarantee schemes are a common form of government intervention to unlock finance for small and medium enterprises (SMEs). A credit guarantee scheme provides third-party credit risk mitigation to lenders through the absorption of a portion of the lender's losses on the loans made to SMEs in case of default, typically in return for a fee.

Besides the credit guarantees proposed by the European Commission, there are further policy measures, which address different PPA related risks and challenges (see Table 8-1). For each policy option, our recommendation can be found in the right column below. Besides the indicated no-regret policy options, we argue that **PPAs should not be forced onto demand with strong regulatory measures**. The main argument for this is that PPAs can disturb the regular price formation and competition on the electricity wholesale market. Based on information received during an interview, this assessment is shared by SMEs on the demand side. We conclude that **PPAs alone will be unable to solve the identified challenges.**

[148] "AAA" and "AA" (high credit quality) and "A" and "BBB" (medium credit quality) are considered investment grades according to S&P and Fitch's rating systems.
[149] Nera analysis based on Fitch (2020): Global Corporate Finance 2020: Transition and Default Study

Table 8-1 PPA policy options and recommendations

	Policy option	Description	Recommendation
Recommended no-regret options	Reduce complexity of PPA contract by providing templates or FAQs	PPA contracts are generally perceived as complex, especially so by SMEs which have limited resources to dedicate to the conclusion of a PPA. This could be addressed by providing templates or FAQs.	We recommend for EZK to not actively get involved on this matter, but instead ask the European Federation of Energy Traders (EFET) to develop a country-specific template for the Netherlands[150] (no-regret option).
	Target large industrial offtakers along the coast	Industrial offtakers have significant offtake volumes and are hence an attractive partner for offshore wind developers. They could be targeted specifically by the ministry, e.g. through a new forum or a targeted information campaign.	We recommend that EZK supports the set-up of a forum in collaboration with industry associations (no-regret option).
	Provide low-interest loans to offtakers to address credit risk	Many offtakers struggle with low credit ratings. These ratings could be improved through low-interest loans, e.g. from the national development bank FMO.	We recommend for EZK to support the provision of low-interest loans by FMO. While they are not as effective in the current low-interest environment, they may become a useful resource towards 2040 (no-regret option).
Not recommended	Offer offtaker guarantee	In an offtaker guarantee, the government could step in when the offtaker fails and the produced electricity still needs to be supplied somewhere. The government could take over and sell the offtake obligation to a new party.	We recommend for EZK to not get involved through offtaker guarantees, as it would stimulate a reduction of the liquidity of the wholesale market.

[150] There are currently templates for France, Germany, Italy, Poland and Spain. **https://www.efet.org/home/documents?id=26**

	Address challenges with matchmaking between interested producers and offtakers	A barrier to the further conclusion of PPAs may be the fact that suppliers and offtakers cannot find each other easily. A successful partner search is crucial. This could be supported by the government through conferences, targeted communication or other means.	We recommend for EZK to not actively get involved here, as there are already private sector initiatives such as the RE-Source conference[151] and platforms to facilitate the matchmaking.
	Tackle aggregation problem of smaller players on the demand side	As we move towards 2040, the actor landscape will change. With increased electrification, more SMEs will look at the PPA market. However, these players may be too small to be interesting as offtakers. An aggregator or the government could address the challenge and bundle several SMEs together for a PPA.	We recommend for EZK to not interfere here as this task should be handled by the market, e.g. by energy traders.
	Subsidies for SMEs	Financial support for the use of PPAs for SMEs could increase the number of PPAs with offtakers in that segment. Financial support could e.g. be granted as a lump sum or as a subsidy per kWh.	We recommend for EZK to not provide subsidies to SMEs. Such subsidies would amount to an indirect demand-side policy. We argue that direct demand-side policies (see section 5.4) are more efficient and hence preferable.
	Address arbitration risk	Under certain circumstances, parties can end the PPA contract prematurely. This arbitration risk could be reduced through regulation, e.g. binding parties to a PPA once it has been signed.	We recommend for EZK to not intervene on this issue, as this is a clause to be negotiated and determined bilaterally between the affected parties. One solution applied by Vattenfall is to establish a joint ownership of the offshore wind farm with the offtaker, which in the case of the Hollandse Kust West project, was BASF.[152] Such an approach could be implemented by others as well.

[151] **https://resource-platform.eu/re-source-2021-event/**

[152] **https://vattenfall-hollandsekust.nl/blog/2021/06/24/vattenfall-en-basf-bereiken-overeenstemming-over-verkoop-van-495-van-offshore-windpark-hollandse-kust-zuid/**

	Obligatory PPAs	Electricity consumers above a certain size or in a certain location could be obliged to close a PPA for their electricity offtake. This would increase the volume of the PPA market and the market-based revenues achieved through it.	We recommend for EZK to not make PPAs obligatory, as this would significantly reduce the liquidity of the electricity wholesale market.

8.1.2 Guarantees of Origin

At an EU level, Guarantees of Origin (GOs) are considered “a key tool for consumer information as well as for the further uptake of renewable power purchase agreements”[153]. GOs are closely related to PPAs, yet different. GOs prove the origin of renewable energy in a transparent way and provide electricity consumers the necessary reliability. GOs and PPAs essentially demonstrate the two dimensions to renewable electricity production - the physically produced electricity and the “green” certificate of the electricity, i.e. the GO. A PPA usually includes both, the electricity delivery and the transfer of the GO. GOs in contrast, can be traded separately to the electricity on specific markets.

GOs by themselves are not a policy instrument. This section – as above – focusses on the policy framework around them. We expect that up to 2040, there will be a **growth of green lead markets**[154]. Companies will have an increasing interest to “greenify” their production processes by switching to electricity from renewable energy sources or green hydrogen in order to address their consumer’s demand for green products. This growth will be driven by an increasingly higher consciousness of end consumers regarding the importance of the energy transition to mitigate climate change.

Currently, the market prices for GOs across the EU are relatively low, as there are too many GOs being pushed into the market with RES support. The market is not in equilibrium, as supply is higher than demand. The **low-price level** is not a significant problem now, because RES are usually additionally supported through support schemes. Project developers are thus not reliant on GOs as a strong revenue source. However, this picture changes when projects do not receive support (as it is happening in the Netherlands under the zero subsidy tenders). In that case, the relative importance of the GO market increases.

In contrast to many other EU Member States, the Netherlands has a **high-quality GO market with high prices**, driven by the demand from the market for high standards. The high quality can be observed in the close geographic and temporal correlation between the renewable energy source and the demand. It can also be observed by the fact that many consumers demand their GOs to come from a newly constructed renewable energy generation asset.

A key task towards the future will be to maintain this quality and the related high price. In case of policy developments at EU level, caution should be given to ensure that a harmonisation across the EU does not lead to a reduction to the lowest common

[153] **https://ec.europa.eu/info/sites/default/files/amendment-renewable-energy-directive-2030-climate-target-with-annexes_en.pdf**

[154] Markets that are created or supported by dedicated public policies to spur innovation by encouraging a leading share of market participants to adopt a certain type of product, material or a new design. **https://static.agora-energiewende.de/fileadmin/Projekte/2021/2021-02_EU_Lead_markets/A-EW_214_Tomorrows-markets-today_WEB.pdf**

denominator but maintains the high value of Dutch GOs. At Dutch policy level, there are several **options** available:

- The RED II revision proposal suggests introducing a requirement for industry that the **labelling** of green industrial products indicates the percentage of renewable energy used following a common EU-wide methodology. We recommend supporting the establishment of a green EU label that clearly identifies green electricity and products produced with green electricity. Such a label would possibly increase the willingness to pay for green electricity or products produced with green electricity. Private initiatives[155] for such labels exist already, but public recognition could underline the high quality of the Dutch GO market.

- A second policy option would be to run an **information campaign** to inform offtakers about the high value of the Dutch GO market. This could help maintaining the comparably high price level of the Dutch GO market. We recommend implementing this policy option.

- A third option would be to drive the **GO market closer to real-time** for corporate offtakers like Google. They are looking to have GOs for 15-minute intervals rather than the standard granularity of one hour. We would encourage the government to assess how high transaction costs for a transition to almost real-time GOs (for offtakers like Google which are looking at 15-minute intervals) would be.

Overall, however, we conclude that while Guarantees of Origin are a useful revenue stream, they **do not provide sufficiently high revenues to mitigate the business case challenge** (or the other challenges for that matter) for the time being.

8.2 In case subsidy-free roll-out fails

Coming from the recent success of **zero subsidies**, the general assumption would be that the market can cope with price uncertainty and that the levelized cost of electricity is below market revenues. However, whether subsidy-free roll-out is possible depends on various factors such as coordination risks, site quality, proximity to shore, whether grid connections are included in the bid or not, permitting procedures, expectations on future wholesale market prices[156], and marketing routes that may transfer some of the revenue risks away from the producer (such as in PPAs). If these factors are not favourable for further subsidy-free development, a support scheme may be necessary.

One element for consideration is the **funding source** for a support scheme. The current SDE ++ is financed by consumers via a surcharge on the electricity bill (ODE). In case the subsidy-free roll out fails and support is required, implications on a social (e.g. for poor households) and economic (e.g. for industry which must compete on global markets) level should be considered. Other options (equally with implications to consider) are the general budget or the revenues from the EU ETS.

8.2.1 Offshore wind

The current support for offshore wind is part of the **SDE++ scheme**. However, offshore wind is treated separately and does not directly compete with other technologies.

In this section, we explore the main support scheme options for offshore wind farms if a subsidy needs to be given (because a subsidy-free roll-out failed). To be clear, **we do not**

[155] For example: **https://www.ok-power.de/**

[156] Wholesale market price developments are highly uncertain. See also section 6.1 for a short discussion on this.

see a support scheme as a fix-for-all in case subsidy-free fails, but rather as an instrument that could contribute to the success of the Dutch offshore wind roll-out – together with a well-functioning power system and sufficient electric demand amongst others.

If governments want to support renewable energy deployment financially, there are several options regarding the **form of support** (see Figure 8-2).

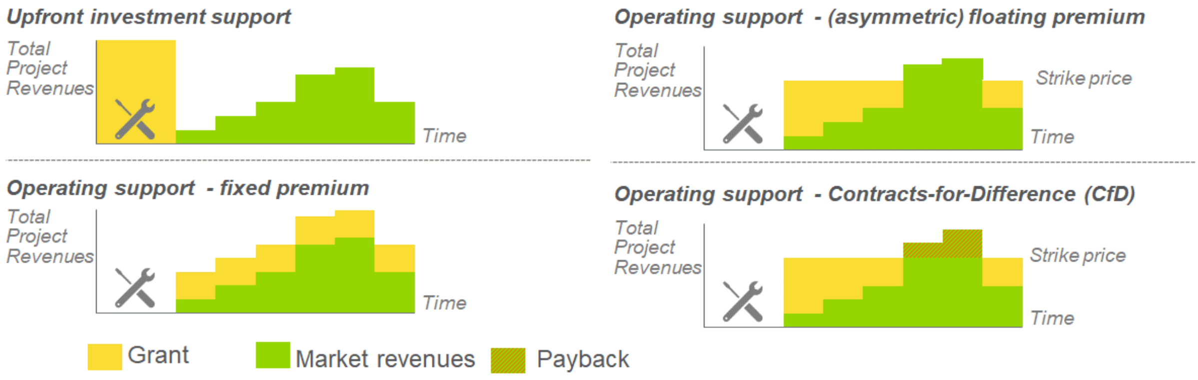

Figure 8-2 Forms of support for renewable energy support

Governments could pay an upfront investment support or operating support in the form of a fixed premium, floating/sliding premium or as a Contract for Difference (CfD). Each form of support is described individually in the tables below. The tables also include an overview of advantages and disadvantages. Lastly, the tables include an assessment how the form of support helps mitigate the three key challenges identified in chapter 2 – the business case challenge, the infrastructure challenge and, thirdly, the integration and interface challenge.

Table 8-2 Description of upfront investment support

<table>
<tr><td rowspan="3">Description:

Investment support usually entails a fixed payment which is related to installed capacity (i.e. x € per kW). This payment can be made upfront or split in several parts (i.e. during the construction phase and at the beginning of the operational phase).</td><td colspan="2">Business case challenge</td><td>To fully refinance their investment, projects are reliant next to the support on market revenues. Projects must anticipate long-term market values (i.e. their revenues), entailing the risk of winner's curse.</td></tr>
<tr><td colspan="2">Infrastructure challenge</td><td>No impact on the infrastructure challenge.</td></tr>
<tr><td colspan="2">Integration and interface challenge</td><td>Incentivises market integration because investors will choose price zones with higher market values (decreasing the support costs and increasing cost-effectiveness of support compared to a floating premium/CfD).</td></tr>
<tr><td colspan="2">Pros:

Compared to operating support, upfront investment support has the advantage of decreasing a project's capital expenditures and thus the required financing volume. This in turn decreases overall capital costs</td><td colspan="2">Cons:

The upfront investment support does not cover all capital costs and the small operating costs of the project. The project is hence also reliant upon revenues from the wholesale electricity market to refinance the</td></tr>
</table>

and, as a result, increases the cost-effectiveness of support.	investment. The fact that bidders must anticipate long-term market values (i.e. their revenues) implies the risk of the winner's curse, i.e. being awarded support which ultimately does not suffice to ensure commercial viability of a project. Another disadvantage of an upfront investment payment compared to a floating premium/CfD (operational support) is that – as in the case of fixed premiums - projects are exposed to full short- and long-term electricity market (revenue) risks, which increases the cost of capital, in turn negatively impacting the cost-effectiveness of support. Another negative effect on the cost-effectiveness of upfront investment support is that a bid selection according to the specific investment costs per capacity does not reflect actual energy production and may result in the selection of bids with comparably higher support costs (per kWh).

Table 8-3 Description of fixed Feed-in-Premium

Description: Fixed premium schemes entail a fixed payment per kWh on top of the market price.	**Business case challenge**	Cannot fully mitigate the business case challenge, as projects are still vulnerable to market price changes.
	Infrastructure challenge	No impact on the infrastructure challenge.
	Integration and interface challenge	A key advantage of fixed premiums compared to floating premium/CfD is that market integration for both operational decisions and investment decision is incentivised.
Pros: Compared to floating premium/CfD market integration for both operational decisions and investment decision is incentivised. More specifically, the long-term market values are relevant for producers, as they will impact the overall revenues of the project. In addition, fixed premiums (and floating premiums as well) imply that market prices are passed on to producers also in the short term who then are incentivized to optimize the production of	**Cons:** Compared to floating premiums or a CfD, fixed premiums, similar to upfront investment support, almost fully expose producers to market price risks, resulting in revenue risks and increasing the cost of capital. In terms of effectiveness, a fixed premium has the disadvantage that it increases the risk of the winner's curse compared to a floating premium/CfD because long-term price forecasts are necessary but always	

the plant. For fluctuating RES with no fuel costs this mainly relates to operation and maintenance issues. Another major advantage of fixed premiums is the simplicity of their design, i.e. no time frames for market price determination or relevant reference markets for projects under the mechanism need to be defined (as is the case in the floating premium options, see below).	related to high uncertainties. This may in turn reduce the financial robustness of the investment and thus the effectiveness of the support scheme.

Table 8-4 Description of floating Feed-in-Premium (FIP)

Description: The support payment is paid as difference between a strike price determined in the tender and a reference market price. There is no pay-back requirement. The reference market price can be determined on an annual, monthly, daily or hourly basis.	**Business case challenge**	Can mitigate the business case challenge, while still leaving the option of zero-subsidy tender rounds open.
	Infrastructure challenge	No impact on the infrastructure challenge.
	Integration and interface challenge	A disadvantage compared to a fixed premium is that market integration is restricted to operational decisions.
Pros: An advantage is that generators are free to decide to bid on a (positive) price below their generation costs (which then effectively functions as a floor price) and expect additional market revenues on top of the support payment or, in case of zero bids, rely on market revenues alone. Sliding FIPs thus retain the option of continuing with zero bids if the market participants are capable. The degree to which market revenue risks can be taken over by project developers are signalled by the submitted bid prices and reflected in the tender results. This flexibility to consider uncertain market revenues in the bid by increasingly lowering the bid price is the key advantage of a one-sided premium compared to a double-sided CfD. Sliding premiums allow for a gradual evolution towards greater market integration, while under a CfD entailing a	**Cons:** A disadvantage of a floating premium may be that RES producers do not pay back in times of high market prices and may be reluctant to price in the additional revenues into their bid, due to the related uncertainty. A disadvantage compared to a fixed premium is that market integration is restricted to operational decisions. More specifically, a floating feed-in premium does not expose participants to risks of long-term market values and therefore does not create incentives for investments towards price zones with higher market values. The upfront determination of necessary support payments for each installation over their lifetime is difficult, as this crucially depends on the production over the lifetime of the installation multiplied with the market values, which are difficult to determine in advance.	

payback requirement, bidders are incentivised to bid a fully cost-reflective bid and market price risks remain with the society rather than project developers.	

Table 8-5 Description of Contract for Difference

<table>
<tr>
<td rowspan="3">Description:

In a CfD scheme, the difference between the strike price in a tender and the market value is paid to the producer in case the market price is below the strike price. A difference is paid from the producer to the auctioneer if the market price is above the bid price determined in the tender. The market price can be determined on an annual, monthly, daily or hourly basis. In practice, however, CfDs are often determined on an hourly basis.</td>
<td>Business case challenge</td>
<td>Can mitigate the business case challenge by offering stable revenues for the support duration, however, the support implies low market integration incentives since project developers are shielded from volatile wholesale prices by offering a guaranteed price level.</td>
</tr>
<tr>
<td>Infrastructure challenge</td>
<td>No impact on the infrastructure challenge.</td>
</tr>
<tr>
<td>Integration and interface challenge</td>
<td>CfDs imply low market integration incentives since they shield project developers from volatile wholesale prices.</td>
</tr>
<tr>
<td colspan="2">Pros:

An advantage of the CfD compared to a floating premium is that its payback scheme ensures that excessive support payments are “paid back” in times of high market prices. This may potentially improve the cost-effectiveness of support, even though this effect is not proven.

In a floating premium scheme, bidders will price expected future revenues into their bids, which leads to lower strike prices than under a CfD scheme. In other words, bidders bid for a floor price under a floating premium scheme and may expect additional market revenues, while they need to bid a fully cost-reflective price under a CfD scheme. The latter reduces the winner’s curse (increasing the effectiveness of support) and may protect smaller market players.</td>
<td>Cons:

A disadvantage may be that CfDs allow for high risk-hedging but imply low market integration incentives since they shield project developers from volatile wholesale prices by offering a guaranteed price level. RES producers are tied to the CfD scheme for the full support period.

When implementing CfDs, attention needs to be paid to the exact design to avoid an inefficient dispatch of offshore wind farms. This includes i.a. the determination of the counterparty, the reference price, a potential strike price inflation, etc.</td>
</tr>
</table>

For a dedicated offshore wind support scheme, **we recommend using a sliding FIP**. CfDs allow for high risk hedging but imply low market integration incentives, since they shield project developers from volatile wholesale prices by offering a guaranteed price level. Under a sliding premium, generators are free to decide to bid on a (positive) price below their generation costs, which then effectively function as a floor price, and expect additional market revenues on top of the support payment or, in case of zero bids, rely on market revenues alone. The degree to which market revenue risks can be taken over by project developers is signalled by the submitted bid prices and reflected in tender results. This flexibility to consider uncertain market revenues in their bid by increasingly lowering their bid price is the key advantage of a sliding premium compared to a CfD. Sliding premiums allow for a gradual evolution towards greater market integration, while under a CfD entailing a payback requirement, bidders are incentivised to bid a fully cost-reflective bid and thus market price risks remain with the society rather than project developers.

The current SDE++ pays support as a sliding FIP. Hence, in case the existing support scheme is reformed, no changes to the form of support are required based on our recommendation. In case a new support scheme is set up, we recommend implementing as the form of support a sliding FIP.

Besides the form of support, there are additional elements to consider for the support scheme:

- **Duration:** For the allocation of support, the duration of the support needs to be determined. Under the SDE++, support is currently being paid for 15 years. The duration may be extended given longer and longer technical lifetimes of offshore wind farms, where 25 years are more common nowadays.

- **Ceiling price**: A price cap or ceiling price can be introduced as a maximum price in a tender, where bids above the ceiling price will be disqualified. A price ceiling can reflect the auctioneer's willingness to pay or limit the risk of high cost due to limited competition or collusive behaviour. The main purpose of ceiling prices is to protect against the risk of inadvertently awarding very high-priced bids. We identified that a concentration of the market on large enough actors for the large-scale developments is a risk that may occur, thereby reducing competition. Ceiling prices are especially important in uncertain competitive situations. For offshore wind, the determination of ceiling prices is well-established. We do not recommend changes to current processes and methodologies.

- **Floor price**: The sliding FIP is paid as the difference between a strike price determined in the tender and a reference market price. The current SDE+/++ scheme includes an additional floor price. If the reference price drops below the floor price, the gap up to strike price is not paid in full. The most recent offshore wind farm that was awarded a subsidy under the SDE+ scheme (Borssele III & IV) has an electricity floor price of 30 EUR/MWh. With increasing volatility of prices, and increasing frequency of very low electricity prices, the floor price can significantly diminish the value of the support scheme. When a support scheme is introduced to deal with these periods in particular, the floor price may be counterproductive. Thus, setting a floor price of 0 EUR/MWh may be considered.

- **Negative prices**: Aside from the floor price, the current rule of stopping payments when prices are negative for a period of six hours or more should be continued.

8.2.2 Offshore wind and electrolysis

Green hydrogen is currently in the early stages of market development. Up to 2040, an acceleration of the market development is expected. However, this ramp-up will likely not come naturally at a quick enough pace through the EU ETS but would require policy support.[157] In the roll-out of offshore wind and electrolysis, the electrolyser could receive support. The EU's sustainability criteria for green hydrogen prescribe that for green hydrogen to be categorized as "green", it must source its electricity from an additional, unsupported renewable energy source. Hence, the offshore wind farm could not receive any support if the produced hydrogen is to be sold as "green". This section discusses in what form support payments to the electrolyser could be made.

A support scheme should consider the differences between renewable energy sources and hydrogen. The **economics** underlying each technology are different:

- Offshore wind has high CAPEX and low OPEX (i.e. wind is "for free" so typically no marginal OPEX, and O&M expenses are limited) which means that it has an incentive to produce as much as possible.

- The electrolyser on the other hand has high CAPEX and high OPEX which means that it has an incentive to only produce when revenues are above costs. The high OPEX is mainly made up of the electricity price.

These differences also have an implication on the form of support. While upfront investment support does not play a role in renewable energy support across the EU, it may be very relevant for electrolysers. In principle, **up-front investment support** may be implemented without any additional (direct or indirect) operating support. However, given the cost of operation (i.e. the cost of renewable electricity), the provision of up-front investment support may not be sufficient to trigger hydrogen production. As a result, minimum generation requirements may be needed. Given the current high investment costs for electrolysers, up-front investment support could be helpful to incentivize investors by partially unloading the financial pressure from the capital expenditure at the beginning of a project. However, only one-third of green H_2 production costs comes from investment, and the other two-thirds are the result of high operating expenses (i.e. the electricity price). Therefore, only providing up-front investment support may lead to risks, such as project failure or discontinuance since it cannot provide financial and operational security throughout the lifetime of the production plant.

Alternatively, **operating support** for every unit of green H_2 produced could be paid. Operating support generally incentivizes plant output, since support is paid per unit of green H_2 produced. Operating support would also reduce the risk of paying support without receiving benefits (i.e. green hydrogen) in case of unexpected project failure. Operating support could either be paid in the form of a fixed or sliding Feed-in-Premium.

The determination of the right type of support is fundamentally connected with the expectations regarding the market development of green hydrogen. For the near-term up to 2030, we expect a green hydrogen market that is characterized by low volumes, few actors and primarily bilateral offtake agreements. This will mean that the actual market price is rather untransparent and that there is no liquid marketplace that will provide a reference price.

[157] **https://static.agora-energiewende.de/fileadmin/Projekte/2020/2020_11_EU_H2-Instruments/A-EW_223_H2-Instruments_WEB.pdf**

One option would be to implement a **fixed FIP**:

- The fixed FIP would be a fixed amount of support that is paid per unit of hydrogen produced.
- The developer would determine the support need based on its assumptions of the hydrogen sales price, its operating costs, and the needed additional revenues to be profitable. The operating costs are largely driven by electricity prices.
- Because this option does not require the tendering authority to apply a reference price to determine the support granted during the operational phase, it rather simple to implement.
- However, there is a risk of over-subsidisation in case the hydrogen market prices increase in the future (see below).

Another option would be a **sliding FIP or Contract for Difference (CfD)**:

- In the tender itself, the bidder bids a strike price. This strike price represents the required revenue level needed by the electrolyser operator to run profitably. The determination of the strike price requires that the electrolyser operator formulates expectations regarding electricity price developments and internalizes these into the bid. Once a strike price is determined through the tender, it is fixed.
- The current SDE++ foresees a sliding FIP with a capped strike price and a floor price. The limit for the strike price is determined by approximating a business case for hydrogen production.
- Currently, the support is calculated annually, as the difference between the strike price and the reference price.

A challenge for hydrogen is the determination of the reference price, which is supposed to reflect the value of hydrogen for the bidder. Since there is no transparent hydrogen market price, a reference price for the value of hydrogen needs to be determined by the government. There is a significant risk that this artificial reference price does not reflect the actual hydrogen sales revenue of the hydrogen producer. This problem does not exist under a fixed FIP, where the bidder determines its own value of hydrogen. However, there are also proxies for the value of hydrogen:

- The SDE++ scheme uses the estimated cost of producing fossil-based hydrogen (indexed on the market value of natural gas) and a correction for the EU ETS price as reference price for hydrogen. Hydrogen projects have not yet been awarded subsidy under the currently technology-neutral SDE++ scheme, as technologies with lower CO_2 abatement cost have exhausted the budget in the two rounds that have been held. A revision of the scheme could provide a separate, technology-specific category for green hydrogen.
- Alternatively, as a proxy reference price until hydrogen markets establish, the EU ETS price could be used. If the EU ETS price is used as a reference, parallels can be drawn to the instrument of Carbon Contracts for Difference (CCfD). Under a CCfD, the government provides support to the industry for decarbonising their processes by tackling the issue of CO_2 prices being too low for their process and/or fuel switching expenses. Thereby, companies determine a certain EU ETS price they would need to make the switch to a more climate-friendly production process. This price is considered the strike price. The difference between the strike price and the EU ETS

price is then paid by the government to the company as support. The fundamental difference between a CCfD and the support scheme discussed here is that CCfDs are technology-neutral (like the current SDE++) whereas the support scheme in question here would be specifically focussed on supporting green H_2 production.

From an economic perspective, it may be beneficial in the beginning to **combine both operating and investment support** for hydrogen. Investment support could phase out over time as the CAPEX reduces. In the longer term, supply-side support may move to demand-side policies (e.g. quotas), as a liquid market (incl. infrastructure) develops. This recommendation holds true for all project configurations including hydrogen discussed in this report.

Setting the ceiling price for green hydrogen support at the right level is a challenge, as costs are changing rapidly. Determining the correct level may require the involvement of expert groups. Within the SDE++ scheme, a ceiling price for hydrogen production was determined by Planbureau voor de Leefomgeving.

When deciding on the duration of support, it should be considered that long-term contracts make it easier for the electrolyser developer to raise finance and may lead to lower bid prices. This may be especially relevant given the immaturity of the green H_2 market. Short-term contracts lead to higher prices per kWh/kg because projects need to recuperate their capital within the shorter timespan (higher cost of finance). This would not be beneficial for the needed demand-side H_2 market ramp-up. However, short-term contracts may encourage a faster development of markets. The SDE ++ scheme awards support to successful bidders for 15 years. For electrolysers, the standard assumption on the economic lifetime is 20 years.

Within the support scheme, the tender item can be defined in several ways:

- When defining the tender item in terms of **capacity** (i.e. the size of the electrolyser in MW/GW), it comes with the advantage that it provides a good planning environment for project developers. It also enables an easy monitoring process in terms of the achievement of policy goals. However, tendering electrolyser capacity does not ensure the maximal operation of the electrolyser (which may sometimes not happen in times of high operating costs) or market-efficient operation (efficient operation being operation during hours of high RES in-feed). The green H_2 production of the electrolysers can thus only be roughly estimated by the government (because it does not have detailed information by the investor on the underlying operating hours used to determine a business case). A resolution would be to implement restrictions such as a minimum on the operating hours.

- Alternatively, the tendered volume may also be defined in terms of **green H_2 production** (i.e. MWh or kg) over the course of a given time frame or an actual annual average. In this case, electrolysers would receive support payments until the production-based target volume is reached. From the viewpoint of the government, this allows for an effective procurement of specific volumes. This is useful, as both the EU and Dutch hydrogen strategies refer to expected demand. However, production-based tender volumes may create problems in terms of inducing higher risks for bidders / project developers as they would have to commit to the delivery of a certain green H_2 production amount rather than delivering a certain capacity over which they have greater control. This may entail that H_2 is produced during hours of relatively high electricity prices, which would not only increase the cost of green H_2 but - depending on the volume - may also increase the shortage on the electricity wholesale market, increasing prices and potentially necessitating the ramp-up of fossil-based electricity production to cover all demand. This effect is only expected at high volumes.

- Finally, the tendered item may be defined in terms of tender **budget** (i.e. €) for electrolysers. Capacities will be tendered until the budget is depleted. This option has the advantage that budget commitments from the hydrogen strategy can more easily be translated into available tender volumes and governments can most easily maintain budget control. If volumes are defined in terms of budget, procured amounts (e.g. MW) will generally depend on the emerging price of the tender (however, restricted by a potential ceiling price). This puts uncertainty on project developers as they do not know how much capacity will be awarded after all.

We would advise against tendering budget, as it provides the least information for the energy system and would instead recommend using either capacity or production volume, as they are more suitable in view of national and EU target achievement.

8.3 Summary of recommendations

Throughout the chapter, the following recommendations were made for a continued subsidy-free roll out:

- We recommend against offtaker guarantees by EZK for PPAs.
- We recommend for EZK to not actively get involved in the matchmaking for PPAs.
- We recommend for EZK to ask the European Federation of Energy Traders to develop a country specific PPA template for the Netherlands.
- We recommend that EZK supports the set-up of a PPA forum in collaboration with industry associations.
- We recommend for EZK to not interfere in the aggregation of demand volumes for PPAs.
- We recommend supporting the provision of low-interest loans by FMO.
- We recommend to not provide subsidies to SMEs.
- We recommend for EZK to not intervene on arbitration risk in PPAs.
- We recommend against making direct PPAs obligatory. PPAs in the context of green hydrogen production may become obligatory for on-grid electrolysers due to requirements of the forthcoming Delegated Act.
- We recommend supporting the establishment of a green EU label that clearly identifies green electricity and products produced with green electricity.
- We recommend running an information campaign to inform offtakers about the high value of the Dutch GO market.

In case subsidy-free roll-out fails, the following recommendations were made:

- For a dedicated offshore wind support scheme, we recommend using a sliding FIP.

- We do not recommend changes to current processes and methodologies for the determination of a ceiling price for offshore wind.

- For a hydrogen support scheme, we recommend to initially combine both operating and investment support for hydrogen. We recommend complementing this supply-side support with demand-side support in the short-term. In the mid-term, when the market grows and becomes more liquid, we recommend shifting the support focus to only the demand-side. In the long-term, support schemes may be phased out and replaced with demand side obligations for hydrogen use, such as quotas.

- For offshore wind and hydrogen tenders, we recommend tendering either capacity or production volume.

Part 3: Legal feasibility of policy options and conclusions

This third and last part of the report looks at a high-level at the legal feasibility of the proposed policy options and the way forward. Specifically, chapter 9 provides a high-level legal feasibility check for key Dutch and EU legislation. The relevant pieces of legislation are analysed with a view to identifying red flags that could be prohibitive to the implementation of the policy options proposed. Chapter 10 concludes the report with some high-level observations, a discussion of relevant limitations of the report and a list of next steps to be undertaken by policymakers for the implementation of the proposed policy options.

9. High-level legal feasibility check of key measures

9.1 Dutch legislation

We have reviewed selected pieces of Dutch legislation to determine the legal feasibility for key recommendations. Within each of the assessments below, we highlight the relevant topics/recommendations and provide a rationale whether we foresee implementation barriers.

Wetsvoorstel Energiewet

Initial considerations:

- This concerns a proposal for a new law and is not yet ratified.
- The Energiewet aims to merge the Elektriciteitswet and Gaswet.
- The proposed act states that all provisions for gas can be made applicable to other gaseous energy carriers besides natural gas, through an Algemene Maatregel van Bestuur.
- The proposal does not yet consider implications from the EC proposal for the recast of the Gas Directive and Gas Regulation.

Table 9-1 High-level legal feasibility check of Wetsvoorstel Energiewet

Chapter	Recommendation	Feasibility assessment	Rationale
Governance	Assigning the e-TSO responsibility for offshore electricity infrastructure	No red flag	The act provides for the assignment of a TSO for the offshore electricity grid/infrastructure
Governance	Assigning an onshore HNO or PPP responsibility for offshore H_2 infrastructure	Potential red flag	The act does not specify an offshore transmission system/network for hydrogen.
Governance	Regulated or negotiated TPA offshore H_2 infra	Potential red flag	To apply rTPA or nTPA, the offshore H_2 infra would need its own definition and provisions, in line with the Gas Directive.
Governance	Directive role national government regarding onshore electrolysis	Point of attention	The act specifies for various energy production and transmission assets a right for the Minister to take project decisions. It does not provide for electrolysis assets.
Governance	Direct connections offshore wind - electrolysis	No red flag	The act allows for direct connections between consumers and the offshore grid.

Concluding, in general the proposal for the Energiewet does not yet provide clear regulatory framework for governance and regulation of offshore electrolysis and offshore hydrogen transmission. It further does not take into account the recently published Gas Directive and Regulation. There may be an opportunity to revise the act (as indicated in the Memorie van Toelichting). The proposed act does provide for the recommended governance of offshore electricity infrastructure, which follows the current approach.

Wet windenergie op zee

Table 9-2 High-level legal feasibility check of Wet wind op zee

Chapter	Recommendation	Feasibility assessment	Rationale
Governance	Application of offshore electrolysis	Point of attention	The act allows for multiple forms of energy, produced by offshore wind farms. It defines connection points as installations or a connection to the offshore electricity grid. In case an offshore hydrogen grid is established, this may warrant a change is this definition. Note, the realisation of an offshore electricity grid is not governed by this law, but the Elektriciteitswet (and if adopted in the future, the Energiewet)
Allocation mechanism	Integrated process that includes both subsidy-free and inclusive bids	No red flag	The act provides for four different award procedures. These are in line with the recommended allocation mechanisms. A choice is made between the options or a combination of options via Ministerial decree. This is in line with the continuous allocation mechanism.
Allocation mechanism	Joint or integrated tenders	Red flag	Although not our recommended tender format, joint or integrated tenders, where both the scope and the award criteria involve onshore electrolysis is not provided for in the act.
Site definition	Further extension of lifetime & permit duration wind farms	Point of attention	The act includes a maximum permit duration of 40 year. In case wind farms are able to extend their lifetime beyond ~35 years, the act may be limiting.

Site definition	Changes to characteristics such as wind farm capacity	No red flag	Such characteristics are set in the Kavelbesluit, thus the act provides flexibility.

Concluding, the Wet Windenergie op Zee is fit for purpose for electrically connected offshore wind farms, although it has a hard cap on permit duration. Offshore electrolysis is possible within the act, the definition of connection point (aansluitpunt) may warrant modification. The act does not provide for allocation mechanisms where wind is combined with onshore electrolysis.

Kaderbesluit nationale EZK- en LNV-subsidie

Table 9-3 High-level legal feasibility check of Kaderbesluit nationale EZK- en LNV-subsidie

Chapter	Recommendation	Feasibility assessment	Relevant wording from act
Support policy instruments	Subsidy in case of joint or integrated tenders	Point of attention	The decree states that subsidisable costs are those directly connected to executing the activity. In case of wind – onshore electrolysis it must be confirmed whether the costs relating to the wind farm can be eligible.
Allocation mechanism	Allocation based on support level and qualitative criteria for offshore electrolysis	No red flag	The decree states that the criteria and weighing of criteria can be set by Ministerial decree.

Besluit stimulering duurzame energieproductie en klimaattransitie

Table 9-4 High-level legal feasibility check of Besluit stimulering duurzame energieproductie en klimaattransitie

Chapter	Recommendation	Feasibility assessment	Rationale
Support policy instruments	Combined investment and operational support scheme	Point of attention	The SDE++ does not provide for investment/CAPEX support. Note, that several EU funds exist which could provide investment support for electrolysis.

Allocation mechanism	Allocation based on support level and qualitative criteria for offshore electrolysis	Point of attention	Provides the option for innovative wind tenders to combine subsidy level and other award criteria. Whether commercial scale offshore electrolysis projects can be considered under this category is uncertain.

9.2 EU legislation

Many pieces of EU legislation have been revised as part of the Fit for 55 package published in 2021. Three proposals are especially relevant in the context of this project: the Renewable Energy Directive II (RED II), the gas markets and hydrogen directive and the gas markets and hydrogen regulation.

With a view to the proposed revised RED II, the following points are most relevant:

- In line with the increased GHG reduction target, the overall level of ambition for RES deployment is increased. While previously the target RES share was at least 32 % by 2030, the current proposal now targets a RES share of at least 40 % by 2030.

- PPAs are explicitly mentioned alongside support schemes as a means of achieving Member State's RES contributions.

- The criteria for RFNBOs apply across all end-use sectors including industry (not only for transport). The forthcoming Delegated Act setting out these criteria is discussed in more detail below.

- With a view to target achievement, only the caloric value (usable energy) of RFNBOs counts as renewable energy, not the RES electricity input. This means that conversion losses from electrolysis are not counted as RES. This provides an implicit incentive for governments to promote the direct use of RES electricity.

- RFNBOs only count for the RES targets in the sector and country where they are consumed not where they are produced. This provides an implicit incentive for governments to also then focus on supporting the consumption of RFNBOs in their country, through either additional production or imports. One such example would be the integrated tender introduced in section 6.2. The other tender options (separate, coordinated, joint tenders) would only incentivise the production, not the consumption of green hydrogen in the Netherlands.

- There are also sub-targets for Member States to increase the share of RFNBOs. For transport, there is a target proposed of 2.6% RFNBOs in transport energy by 2030 (part of RES-T obligation). For industry, there is a proposal for a 50% target of RFNBOs in hydrogen use in industry by 2030. Industry is for the first time in the focus of RED. The obligation for target achievement is for the industry target on the government, not the industry directly.

With a view to the proposed revised gas markets and hydrogen legislation, key points include:

- According to the Commission's proposals, hydrogen networks and gas networks must be run separately under company law. However, Member States may allow gas network operators to temporarily cross-finance hydrogen networks, if they meet certain transparency requirements and do not charge consumers in other member states.

- A European Network of Network Operators for Hydrogen (ENNOH) is to be established to ensure the smooth development and market ramp-up of a European hydrogen network. Unlike for natural gas, with hydrogen there seems to be no distinction between upstream and regular transmission lines, just the umbrella term of 'hydrogen networks'.

- Offshore hydrogen networks are mentioned specifically in item 66 of the recitals of directive. Equally onshore and offshore, regulated third-party access on the basis of regulated access tariffs should be the default rule in the long-term. In order to ensure the necessary flexibility for operators and to reduce administrative costs during the ramp-up phase of the hydrogen market, Member States have the option to allow the use of negotiated third-party access until 2030.

- Analogous to the previous unbundling requirements for natural gas, it is proposed that hydrogen production and supply should not be in the same hands as the operation of the H_2 networks. However, Member States may choose an alternative unbundling model of "integrated hydrogen network operator" until 2030. This will allow vertically integrated owners of hydrogen networks to retain ownership of their networks while ensuring the non-discriminatory operation of such networks after 2030.

- The directive mentions localised hydrogen clusters as an important building block of the European hydrogen economy and opens the option of such clusters benefiting from simplified regulatory requirements during the ramp-up phase of the hydrogen market.

The vision developed here considers these targets, signals, and considerations. There is no red flag identified.

Besides these more overarching pieces of legislation, there are others which are highly relevant with a view to the concrete recommendations made throughout the study. These are analysed below.

Table 9-5 High-level legal feasibility check of the revised Climate, Energy and Environmental Aid Guidelines (CEEAG) [158]

Chapter	Recommendation	Feasibility assessment	Relevant wording from act
Allocation mechanism	Use tenders to allocate sites and support in case needed	No red flag identified	Aid for reducing greenhouse gas emissions should in general be granted through a competitive bidding process, so that the objectives of the measure can be attained in a proportionate manner which minimises distortions of competition and trade.

[158] **https://ec.europa.eu/competition-policy/document/download/2049b565-5e6b-4153-a022-e70db769086f_en**

Allocation mechanism	Option 1,2 and 3 for offshore wind	No red flag identified	For the allocation of aid, other criteria than the support bid must account for not more than 30 % of the weighting of all the selection criteria. Options 1 and 2 ask for zero-subsidy bids. Here, no support is allocated and hence this limitation does not apply. For option 3, we propose a price-only evaluation of the support bids, which is fully in line with the CEEAG. Only in case of multiple zero-subsidy bids, we propose a combined assessment of the quality and willingness to pay (capped financial bid). Here, the same reasoning as above applies – other award criteria can be used, as no support is being awarded.
Support scheme	Provide a sliding feed-in-premium for offshore wind in case subsidy-free roll-out fails and a both investment aid and operating support for hydrogen production	No red flag identified	Aid for decarbonisation can take a variety of forms including upfront grants and contracts for ongoing aid payments such as contracts for difference. The proposed Feed-in-Premium is covered by this.

Overall, on a high-level, the recommendations made in this study are in line with the revised Climate, Energy and Environmental Aid Guidelines.

Table 9-6 High-level legal feasibility check of Delegated Act (based on leaked draft version)

Chapter	Recommendation	Feasibility assessment	Relevant wording from act
Support scheme	For offshore wind and electrolyser projects, only the electrolyser scope can receive support.	No red flag identified	The Delegated Act will likely require that the renewable electricity generation capacity used to supply the electrolyser does not receive financial support since the renewable hydrogen is already being supported.

Allocation mechanism	Electrolysers must consider system when determining operation.	No red flag identified	The Delegated Act will likely require that hydrogen producers show that the production of renewable hydrogen takes place in the same calendar hour as the production of the renewable electricity, that more renewable electricity is being produced in the bidding zone than on average or that renewable electricity that has been locally stored during such time periods is used.
Allocation mechanism	Government defines priority areas for electrolyser deployment	No red flag identified	The Delegated Act will likely allow Member States to set out additional criteria concerning the location of electrolysers.
Allocation mechanism	Off-grid electrolysers	No red flag identified	The Delegated Act will likely require for off-grid electrolysers that the installations generating renewable electricity came into operation in the same year as the electrolyser or later.
Allocation mechanism	On-grid electrolysers	No red flag identified	The Delegated Act will likely require for on-grid electrolysers that the installation generating renewable electricity came into operation not earlier than 24 months before the installation producing the renewable hydrogen, and does not receive support in form of operating aid or investment aid.

The recommendations made in this study were developed with the requirements of the Delegated Act in mind. However, the Delegated Act is still being drafted at this moment. Once a final version has been published, the legal feasibility check should be repeated.

10. Conclusions and discussion

This study was written in a context of high ambitions, manifested first and foremost in the increased European GHG reduction target. The need to streamline legislation towards this increased target, has led to the publication of the Fit for 55 package. Therein, increased RES targets are proposed for 2030 as well as new targets, e.g. for the use of RFNBOs in industry.

As an effect of these targets, there will be a large need for electricity from renewable energy sources for direct electrification and the production of green hydrogen. This puts pressure on offshore wind as a key renewable energy resource in the Netherlands. The goal of this study was to obtain an overview of the possible policy options and instruments for a new approach to offshore wind energy.

This conclusion is split into two parts. First, we provide some high-level observations based on the analysis completed in this study. Secondly, we want to discuss the findings of this study, both with a critical view as to which elements require further analysis as well as a recommendation for next steps to be taken by policymakers.

10.1 High-level observations

Most of the recommendations provided in this study are focused on concrete elements of the larger view onto the offshore wind roll-out until 2040. Here, we take a step back and provide five high-level observations:

- **Observation 1: 2040 is closer than it may appear and 2030 is essentially just around the corner.** The masterplan we propose and recommend in this study provides an overview of the time periods that need to be considered before an asset can become operational. Especially for infrastructure, the current lead time of 10-12 years means that acceleration is key to achieve the targets set out for 2030. Large scale electrolysers are currently expected to require a lead time of 7-8 years. To have a chance at realising the hydrogen targets for 2030, policy should be developed and implemented still this year.

- **Observation 2: Coordination and infrastructure challenges warrant a strong involvement by the Dutch government.** The above-mentioned masterplan requires decision-making by the government at three instances in time. Most important is the decision by the government on how a certain area will be connected – through cables, pipelines or both. Also, for the coordination of processes and stakeholders, a strong role by the government is required. The joint offshore wind – industry roadmap 2040 requires that the government brings actors together to accelerate planning and permitting. It also requires the government to plan and act in an integrated manner and across topical boundaries. Supply and demand need to be considered in tandem.

- **Observation 3: Hydrogen could become a cornerstone of the 2040 offshore wind roll-out.** A significant part of this study is dedicated to the role of hydrogen until 2040. And that is with due cause – while traditionally offshore wind has been considered for the supply of electricity, in the future it will also be needed to produce green hydrogen. The proposed RFNBO quota of 50% in industry by 2030 will require significant renewable electricity, and possibly 6 GW of additional offshore wind to facilitate this without detriment of decarbonisation of other electricity use. Hydrogen may also become highly important from an electricity grid perspective. Electrolysis may help alleviating electricity grid congestion.

- **Observation 4: Developments in the Netherlands are highly influenced by policy developments at EU level.** Many pieces of legislation currently discussed or drafted have important implications for how the offshore wind roll-out in the Netherlands can be implemented. Three are especially relevant – the RED II revision, the gas markets directive and regulation and the Delegated Act on the sustainability criteria for RFNBOs. The documents define the level of ambition for renewable energy and hydrogen, the focus of hydrogen consumption, the support frameworks for hydrogen and the role of PPAs.

- **Observation 5: The offshore wind industry wants to make the offshore wind roll-out a success – without support payments to wind farms.** The wind industry parties involved in this study have been outspoken and underline the importance of setting the right framework conditions so that offshore wind can succeed without support payments.

10.2 Discussion

While this study did discuss a broad range of topics, there are some topics which were out of scope and thus not considered in detail. However, for a full picture of relevant considerations, these **limitations** should also be discussed. Relevant topics outside this study's scope are:

- **Demand side instruments**: This study did not focus in detail on demand side instrument for the consumption of electricity and/or hydrogen. The development of electricity demand through direct electrification as well as electrolysis is a key determinant for the profitability of future offshore wind. The Dutch wind industry, through NWEA, have developed relevant ideas in this context. The interaction of demand side instruments and recommendations made in this report require analysis.

- **Instrument for hydrogen market ramp-up**: This study did not take a comprehensive look at building blocks required for a ramp-up of the hydrogen market. In this context, we refer to a study by Agora Energiewende and Guidehouse for a first overview of relevant elements.[159]

- **Instruments for infrastructure ramp-up**: The European Commission just recently published the proposal for the recast of the gas package, e.g. roles and responsibilities, regulation and the financing models for hydrogen grids. The proposals included there should be considered as a complementation to the offshore infrastructure governance considerations made in this study.

Looking at elements mentioned or discussed in this study, we analyse that there are a number of elements which require **further analysis**:

- Once the Delegated Act on the sustainability criteria for green hydrogen is published, we recommend reviewing whether the recommendations made throughout the report still hold. We also recommend analysing in more depth PPA configurations between electrolyser and offshore wind operators.

[159] Agora Energiewende and Guidehouse (2021). Making renewable hydrogen cost-competitive. Link: **https://static.agora-energiewende.de/fileadmin/Projekte/2020/2020_11_EU_H2-Instruments/A-EW_223_H2-Instruments_WEB.pdf**

- This study was largely focussed on developments in the Netherlands. Further analysis is required on how these developments interact with the international dimension.

- We also recommend cross-linking the considerations developed here on governance with the broader international market arrangement considerations for offshore wind and offshore electrolysis with energy islands (e.g. Offshore Bidding Zones).

- For the governance of the future offshore wind and electrolyser deployment further analysis on regulation of offshore energy hubs and islands (i.e. shared substructures) is needed. In Denmark, legislation on the Danish energy islands is expected to be published in summer of 2022.

- We recommend using the allocation mechanisms considerations developed here as a starting point for a detailed tender design.

- For the assessment of the height of financial bid caps require separate analysis (in connection with market consultation).

- We recommend verifying the legal options to combine a subsidy award procedure with qualitative criteria for the allocation mechanism for offshore wind and offshore electrolysis.

- As this study focussed on offshore wind, the working group did not include all actors that are relevant for decisions on governance models of for offshore hydrogen infrastructure. We recommend to additionally engage with the actors in the on- and offshore gas industry to uncover the lessons learnt in the Dutch gas industry and to further test the recommended models.

- We recommend to further investigate this hybrid between off-grid and on-grid onshore electrolysis, the possible associated governance models and legal implications.

- We also recommend engaging with electrolyser manufacturers and developers to understand whether it is feasible to define the characteristics of an electrolysis plant for the purpose of executing an environmental impact assessment.

- We recommend to further examine the realisation period of large-scale electrolysers.

10.3 Next steps for policymakers

As discussed at the beginning of this chapter, the ambitious 2030 targets require action by policymakers still this year. Therefore, we want to conclude this study with an overview of recommended **next steps for policymakers**:

8. **Initiate processes for the masterplan**: A necessary next step for the masterplan would be to engage with all relevant actors on the idea of the masterplan to create buy-in from TSOs, the wind sector and industry. Start by further defining the activities in the different phases and the decision-making processes to follow. Determine applicability to ongoing offshore wind developments.

9. **Start conversations for the joint offshore wind – industry roadmap 2040:** A crucial element of the joint roadmap is the coordination of the different actors. The government should identify in a first step the relevant actors (TSOs, industry, wind

sector, local representatives, government representatives) and start the engagement with these actors. In a second step, the government could start summarising the main targets, schedules and dates determined for the development of industry decarbonisation efforts and offshore wind by other policies. This would form the basis for the joint yearly schedule for offshore wind roll-out, industry electrification and green H_2 uptake until 2040. Within the joint roadmap, we recommend to investigate acceleration opportunities for permitting and infrastructure realisation timelines.

10. **Define national hydrogen production target:** With the caveat that negotiations on the Fit for 55 package are still ongoing, a discussion on the required hydrogen volumes and the shares between imports and domestic production should be initiated with the view to defining a national hydrogen production target.

11. **Provide clarity on the future electricity and hydrogen market set-up:** Market parties require a view on the future market set-up which considers international and cross-border developments. To provide such clarity, the government should communicate its expectations for the future market set-up.

12. **Decide on governance model(s) for offshore hydrogen infrastructure:** Before concluding on the best-suited governance model(s) for offshore hydrogen infrastructure, further discussion on advantages and disadvantages of the options is needed. This requires involvement of all relevant actors and due consideration of the regulatory framework set at EU level and experiences made in other sectors.

13. **Initiate processes for short-term funding line for integrated projects:** To ensure fast ramp-up of electrolyser capacities, a funding line for integrated projects could be considered. In a next step, the detailed legal implications of this proposal should be assessed and the interest in the market for participation in this funding line should be examined to ensure that budget is made available.

14. **Conduct a detailed study of a future offshore hydrogen network:** This study would provide insights into the required timing of realising an offshore H_2 network, technical and commercial specifications of such network, and provide insights into the opportunities of reusing existing pipelines.

15. **Carry out in-depth legal feasibility check:** The high-level legal feasibility check was not performed by lawyers and should be repeated in-depth by the relevant legal experts. A review of the assessment made here is also needed once the Delegated Act has been published.