ENERGINET
Systemansvar

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SYSTEM PERSPECTIVE ANALYSIS 2022

PATHWAYS TOWARDS A ROBUST FUTURE ENERGY SYSTEM

Analysis focusing on cost-effective and robust system solutions for climate neutrality, large-scale offshore wind power and the green energy industry

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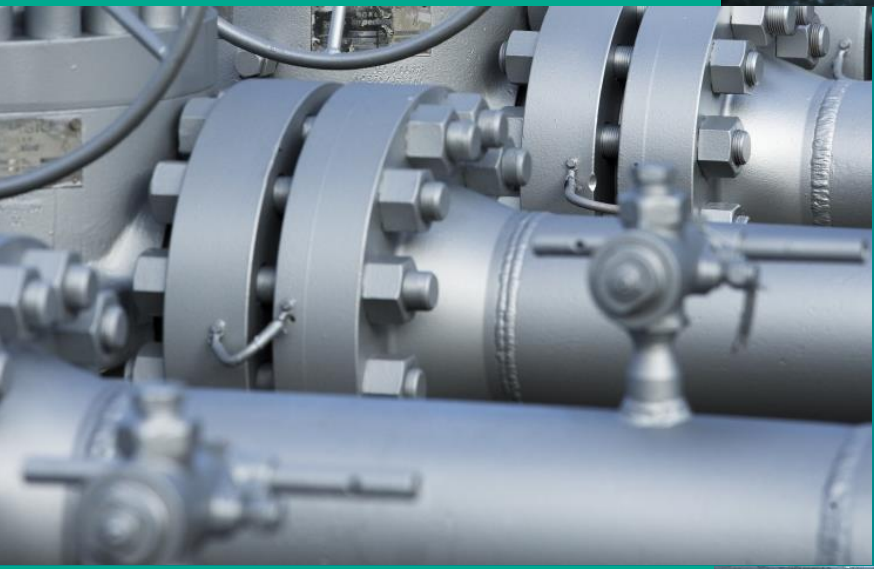

SYSTEM PERSPECTIVE ANALYSIS FOR DEVELOPMENT PLANS, KNOWLEDGE SHARING AND INSPIRATION

The purpose of Energinet's system perspective analyses is to analyse possible long-term development processes for the energy system as a unified system, and to provide input based on this to the long-term planning of electricity and gas infrastructure and the broad system development necessary to handle the significant transformation that the energy system is facing.

The base case assumptions of this analysis is the expectation of how the Danish energy system will look in 2030, following implementation of the initiatives from the Danish *Climate Agreement on green power and heating 2022* (June 2022), and *Analysis assumptions 2022*. From this ambitious foundation, possible development paths are simulated for the period after 2030 and towards a climate-neutral energy system. The energy system will be developed rapidly towards 2030, but infrastructure and energy consuming and generating plants are not just elements in achieving our 2030 aim. These elements will be an integral part of the Danish energy system throughout their lifetimes, which are expected to span up to 50 years. The analysis is used to place the current development in a long-term perspective, with several possible outcomes, and to assess the robustness of current initiatives and identify interdisciplinary common ground and synergies.

The report builds upon several other analyses and projects, such as Energinet's previously published report, *System perspectives for the 70% target and large-scale offshore wind power /26/,* the *RE-INVEST project/10/,* etc. A number of conclusions about the development of the energy system towards 2030 that have previously been thoroughly analysed and examined will therefore not be discussed in detail in this analysis. For example, that direct electrification of large parts of energy consumption is essential to the green transition, and that comprehensive digitalisation of the energy sector is absolutely necessary in order to realise the potential of sector coupling.

The report presents a range of other general and specific issues for the energy system, and summarises in the last section how these result in various development needs and long term R&D at Energinet.

Transformation of the Danish energy system will require extensive interplay across sectors, and we hope that the analysis will contribute to putting the wider development in perspective, and inspiring broad dialogue on the development paths towards a climate-neutral energy system.

SUMMARY OF CONCLUSIONS

- **Integration of electricity, gas and hydrogen infrastructure essential to a robust Danish energy system**
  Expanding renewable energy (wind/solar) after 2030 to as much as 35 GW of offshore wind power in the Danish part of the North Sea has been analysed (a tenfold increase in renewable electricity generation compared to today). A decisive factor in making expansion on that scale possible will be to design a future hydrogen system that caters to the long-term aims and is co-optimised with the electricity system. If this is achieved, Denmark's infrastructure can be geared to both climate neutrality and a massive expansion of RE and PtX, such that the great RE potential of the North Sea can be realised. Establishing hydrogen infrastructure can reduce the amount of visible electricity infrastructure required, compared to alternative scenarios without hydrogen infrastructure.

- **Offshore hydrogen production may become relevant**
  The optimum model for system integration of offshore wind power depends on the distance from coast to wind farm. Analysis shows that for shorter distances (less than 50 km), AC connected wind farms with land-based electrolysis plants are most cost-effective. For larger distances, the most cost-effective solution could potentially be electrolysis at an offshore hub, or integrated into wind turbines. The development new offshore electrolysis configurations are not essential in order to realise the North Sea potential, but the framework for developing wind projects and potential offshore hydrogen infrastructure should open up for utilisation of this potential. The work with energy islands/hubs in the North Sea has moved in a direction in recent years whereby distributed platforms are also an important part of the solution.

- **Flexibility offers new opportunities for utilising the power grid**
  Towards 2030, flexible resources such as PtX, electric vehicles, heat pumps, batteries, etc. could potentially be expanded so significant that they account for more than 20 GW flexible capacity (approx. four times the power station capacity in 2022). By exploiting this flexibility in system operation (as supplementary grid reserves and geographical regulating power bids), utilisation of the electricity grid can be increased. This will make system operation more complex and require significant development, and closer interplay between TSO and DSO to utilise these resources.

- **Gradual adaptation of market solutions to the integrated energy system**
  Integration of up to 35 GW of offshore wind power combined with expansion to onshore wind and solar power is such a significant change that closer interplay between the energy markets and the physical infrastructure for electricity and hydrogen will be central in the integrated energy system. Energinet is currently focusing on this in the development of tariff and ancillary services solutions. Developing solutions that more strongly couple the market and the physics of the integrated energy system remains an important focus area.

- **Large volumes of wind and solar power will change the system dynamics**
  A high degree of electricity system utilisation, closer to the physical limit, will increase the need for a high level of built-in robustness. Operation of thermal plants delivering grid-forming services is reduced in the wind- and solar dominated power system. New resources to deliver grid-forming capability is a focus area. Significant expansion in power electronic interfaced devices as wind and solar, HVDC connections, PtX-plants, electrified heating and transport is potentially new resources to deliver grid-forming capability and R&D in this area is essential for the future climate neutral sector coupled energy system.

- **New technologies for converting methane gas may be an important link between methane, hydrogen and CO_2**
  Through new technologies like eSMR (electricity based gas reforming) and established gas storage facilities, the methane gas system can work together with the hydrogen system towards the production of green fuels. Integration of hydrogen and the methane gas system and storage facilities is important in both a Danish and a European transition, to ensure security of supply.

SUMMARY

The future Danish energy system is characterised by expansion of green energy and a high degree of sector integration. This conclusion is supported by many analyses and declared political aims.

This analysis takes this as its starting point, and focuses on the long-term development of the energy system starting in 2030, towards a climate-neutral energy system. Various infrastructure, market and system operation initiatives are explored along the way across a broad range of future outcomes, and the robustness of the initiatives to various outcomes will be tested in a general economic and technical optimisation model. The result is the summary conclusions presented on page 5, and the identification of ten vital elements which the current development must accommodate in order to get the most from the sector-coupled system.

1) Efficient integration of large volumes of offshore wind power will lead to onshore (and possibly offshore) hydrogen production

The analysis looks at various models for realising an expansion of up to 35 GW offshore wind turbines in the Danish part of the North Sea. Some of the electricity generated will be used for direct electrification, but a significant portion will go to hydrogen production via electrolysis. Various offshore models have been assessed with different locations for electrolysis: 1) at the landing point, 2) in offshore hubs, and 3) in dedicated hydrogen-producing wind turbines. This includes 'overplanting', whereby electrolysis is established at the landing point so that the wind farm can be larger than the feed-in capacity available on the electricity grid.

For offshore wind power with radial landing (normal for offshore wind power today), land-based electrolysis is most cost efficient. At greater distances, where HVDC is necessary to bring the power ashore (typically more than 50 km), a combination of onshore and offshore electrolysis can potentially be most cost-effective.

Standardised offshore models are undergoing major development, and there is an international focus on platform solutions for electrolysis, dedicated hydrogen wind turbines etc. It is important when developing offshore energy hubs/islands to focus on the interplay with the latest technology developments. Read more on page 23.

2) Synergies between hydrogen and electricity infrastructure

Hydrogen infrastructure will play a key role in ensuring the efficient integration of the major volumes of wind- and solar power production to be established in the coming years. This may significantly help to limit the need to establish overhead lines, if its location and operation are integrated with the electricity system.

The establishment of hydrogen infrastructure and storage has been analysed in relation to a long-term potential of up to 35 GW of offshore wind power in the Danish part of the North Sea. It is deemed to be both practical and possible to establish hydrogen infrastructure towards 2030, such that it supports the continued expansion of large-scale offshore wind power in DK.

The availability of cheap large-scale hydrogen storage is key in order to exploit the flexibility offered by hydrogen production. Access to large scale hydrogen storage can ensure utilisation in plants that further refine hydrogen to ammonia, jet fuel, other industrial products ect. Simply establishing a hydrogen pipe system will already provide storage in the form of pipe capacity (linepack), whether connected to the caverns or not.

The analysis shows that the combination of linepack (high storage capacity throughout the day) and cavern storage (which can provide weeks/months of storage), could make a positive contribution to balancing the energy system and security of supply. Read more on page 23 and page 26.

3) Price signals to handle investment and system adequacy

In the scenarios, the electricity system is expanded from handling approx. 20 TWh annually of wind/solar power, to eventually handling more than 250 TWh from offshore and onshore wind and solar power. This is such a major change that the interplay between the market and the physics of the electricity system will be key. Ideally, market signals for investment in and operation of energy facilities should more closely

reflect the physical conditions and limits of the integrated energy system, in order to best utilise the infrastructure.
In the analysis, such optimisation is modelled using a division into 10 electricity market areas that express the market price, and a similar number of smaller energy co-location zones. Several measures can also be applied to the interplay between the market and physics, which are not examined further in this analysis. These measures can range from tools in the regulating power market to specific connection agreements or a finer price area subdivision. The important thing is to create the right incentives to ensure that the flexibility from the new consumption, such as PtX, heat pumps, electric vehicles, storage facilities etc. is best utilised to integrated renewable energy without grid overloads.

With the closer coupling between the market and physics to ensure system adequacy, the notion of security of supply will come to be more dominated by system security (a strong focus on ensuring operation of the electricity system remains intact if an incident occurs). Market solutions where the real-time price/regulating power price is broadly available to end consumption in the right geographical resolution may be key to achieving sufficient security of supply in a cost-effective manner. This is a major system change from today, where a lot of demand-side response reacts to the day-ahead price, and therefore cannot react to a more acute incident in the system, where there is a need to consider production capacity and grid status in real time. Read more on page 31.

4) Higher utilisation of electricity infrastructure with demand-side response as grid reserve

The electricity system is currently operated under the basic premise that consumption must not be disconnected during normal operation. Reserve capacity is therefore always included in the electricity grid as part of system operation, to handle electricity transmission and production outages without disconnecting consumption. The new vast and potentially flexible electricity consumption from PtX, electric vehicles, heat pumps etc. will make it possible to free up some of the traditional reserves in the power grid for increased electricity transmission, by allowing flexible electricity consumption to be quickly reduced via market signals if incidents occur in the electricity grid that necessitate this. This could increase utilisation of grid capacity.
Read more on page 33.

5) Efficient TSO-DSO interaction is essential to operate with distributed production and consumption

The strong electrification at end consumption, in the form of heat pumps, electric vehicles, solar cells, batteries etc., makes the interplay between TSOs (transmission companies) and DSOs (distribution companies) important. With effective price signals at TSO level, market solutions to handle electricity grid congestion right out to end consumption (DSO) are also essential. The analysis shows that already prior to 2030, congestion may occur at DSO level in hours when electricity prices are low, eg due to electric vehicles being charged and heat pumps running in these hours.

New initiatives such as more dynamic tariffs at DSO level to handle congestion during hours of low electricity prices at TSO level may be one way to address this. This means that good interplay between TSO/DSO market solutions will be key in the future electricity system.
Read more on page 36.

6) Activating new resources for grid forming capability

System stability has not been analysed, but access to resources capable of providing gridforming services has been assessed. Power production from thermal power plants traditionally delivering gridforming system response, is reduced considerably towards 2035. Large power electronic interfaced assets like wind-turbines, solar plants, HVDC interconnectors and PtX-plants can potentially provide voltage control and system stabilisation with inertia and other essential grid forming properties. It is therefore an important focus area to evaluate the perspectives in activating these new resources to ensure stability in the electricity system. This includes the necessary efforts to develop system solutions and standardisation for future offshore wind farms and PV power plants etc., as well as ongoing

control room development with dynamic stability monitoring (DSA).
Stability can to some extent be ensured using synchronous condensers, and in special circumstances, through the forced operation of central power stations. Experience has shown the latter to be a costly solution, and less available in the longer term. The continued development of properties required to maintain power system stability in step with the expansion of wind and solar is therefore a focus area.
Read more on page 34.

7) Biogas export potential and high-value PtX products
Analyses show direct electrification of heating and parts of industrial process heat to be cost-effective. The need for methane gas for heating and industry is therefore expected to decline significantly in the years ahead. At the same time, biogas production is being rapidly expanded. Towards 2030, biogas production is expected to be able to meet national gas consumption. If the biogas expansion continues, production will often exceed gas consumption in many gas distribution areas. The development path to handle this could be to export upgraded biogas, but the analysis also shows that electricity driven refining of biogas into high-value products, such as jet fuel, is an attractive option, aligned with the vision of climate neutrality in Denmark.

New electricity-based technologies such as eSMR (electrically driven steam methane reforming) can be brought into play to decompose methane and biogas (including CO_2) into synthetic gas (hydrogen and CO). This opens up a number of new opportunities for using biogas and electricity to produce high-value products such as jet fuel.

The eSMR technology has been investigated in scenarios and innovation projects for some years. System solutions using eSMR can be placed centrally in the large sector coupling zones, at regional nodes where biogas, hydrogen and CO_2 are coupled with PtX production, or locally alongside large biogas plants. Strong cooperation between TSOs and DSOs regarding gas will be valuable in order to assess the opportunities this technology potentially offers.
Read more on page 38.

8) CCU/CCS in combination with PtX
Both CCU (carbon capture and utilization) and CCS (carbon capture and storage) have considerable long-term potential in the scenarios. Captured fossil CO_2 is considered to mainly be relevant for CCS, where there is a significant potential to rapidly capture and store CO_2, e.g. from cement production, fossil refinery activities and the combustion of fossil waste. For CCU, it is assumed that primarily non-fossil CO_2 will used in the production of green fuels. CO_2 from biogenic carbon is currently mainly available from biomass CHP plants and biogas plants.

In step with the major expansion in wind and solar and a rising proportion of waste heat available from PtX, the operating time for bio-CHP plants will be markedly reduced.
Reduced operation of thermal CHP-plants further highlights the need for wind and solar to stabilize the grid (gridforming capability). See also point 6.
Reduced operation of thermal plants also decrease bio-CHPs as a CO_2-source for PtX. Other pathways delivering bio-carbon to PtX-fuels seems to be more cost-efficient. Eg. pyrolysis paths, hydrothermal liquefaction (HTL), thermal gasification etc.

Direct use of biogas for fuel production (eSMR) might also reduce the availability of CO_2 from biogas upgrading. Overall, these developments mean that there could be a shortage of non-fossil CO_2 for PtX in the short term until direct air Capture (DAC) is mature. Given the quite limited access to non-fossil CO_2, it will be a challenge if this CO2 is stored (CCS) under long-term contracts, which might prevent the possibility of scaling up PtX for RE diesel, jet fuel etc. (CCU).
Read more on page 41.

9) Direct air capture in combination with PtX expected to be cost-effective after 2030
CO_2 capture from atmospheric air (DAC) is a technology which can potentially capture CO_2 for CCU and CCS at a price below € 200 per tonne within the next 10 years.

The technology which currently looks very promising uses heat at approx. 100°C as input. There is therefore a very clear potential symbiosis with PtX production, which emits heat (eg from electrolysis and jet fuel production). Kick-starting this symbiosis is therefore an important focus area in relation to the goal of climate neutrality. Read more on page 43.

10) Climate neutrality, green industry and exports

A climate neutral system in Denmark has been analysed. Given an efficient sector coupling, enhanced coupling of market and physics in system operation, establishment of hydrogen infrastructure, major electrification of the heating and transport sectors and scaled up PtX and DAC, a system can be established that fully supports overall climate neutrality in Denmark.
This assumes a need for negative emissions of 10 million tonnes of CO_2 from the energy sector through carbon storage from carbon capture, pyrolysis and solid biogenic carbon storage, so that emissions from activities outside the energy sector are balanced.

With a 6 GW energy hub in the Danish part of the North Sea, electricity will be available to make Denmark climate neutral in 2035 (incl. international aviation and compensation for emissions outside the energy sector). This entails a number of initiatives, as mentioned, and will require a focused implementation effort.

It is not for Energinet to decide whether this scenario of rapid climate neutrality should be realised. If the described infrastructure initiatives (including hydrogen) and efficient sector-coupled system operation are realised, it will be possible to upscale offshore wind power to 35 GW in the period up to and after 2035.

This will provide a foundation for significant growth in the green energy industry, and exports of electricity, hydrogen and high-value refined energy products – such as jet fuel, methanol and ammonia.
Read more on page 44.

A need for R&I to pave the way for system transition

There is a need for significant system development and specific research & innovation (R&I) to pave the way for the integrated energy system based on 100% renewable energy and delivering a negative carbon emission. Based on the scenario analysis some perspectives for system R&I are described.
Read more at the section "*Perspectives for System development*" at page 45.

NATIONAL FRAMEWORK AS THE BASIS FOR SCENARIOS

THE CLIMATE AGREEMENT OF JUNE 2022 SETS THE FRAMEWORK FOR DENMARK'S AIMS FOR THE ENERGY SYSTEM TOWARDS 2030, AND ONWARDS TOWARDS CLIMATE NEUTRALITY

The Danish climate agreement on green power and heating 2022 (the Climate Agreement) contains a target of a fourfold increase in generation from onshore wind turbines and PV power plants. This will generate around 60 TWh of electricity annually, in total. There is also an aim to establish additional offshore wind turbines, to achieve total capacity of more than 10 GW during 2030.

With minor peak-load electricity generation based on green fuels, renewable electricity generation will exceed 100 TWh annually in total. This is more than a fourfold increase compared to the renewable electricity generation from 2022! This large amount of electricity is required in order to supply the ambitious direct electrification of heating, industry and the transport sector, and thereby meet the target in the Danish Climate Act of a 70% reduction in greenhouse gas emissions in 2030 compared to 1990. There is also enough electricity for the 4-6 GW of electrolysis plants in the PtX agreement, which the aim is to establish by 2030. These developments make the energy system of the future dramatically different, and more sector integrated than is the case in Denmark today. The development outlined in the Climate Agreement is used as the reference scenario for the analyses in this report.

EXPLOITATION OF NORTH SEA POTENTIAL

The climate agreement addresses not only the 2030 aims, but also looks further ahead. The Danish offshore wind resources far exceed the energy Denmark needs to complete the full transition to climate neutrality.

The scenario with a 6 GW offshore wind hub in the North Sea already provides enough electricity generation to supply a Danish transition to climate neutrality. Electricity generated beyond this can be exported as electricity, hydrogen or renewable fuel, or supply new industry.

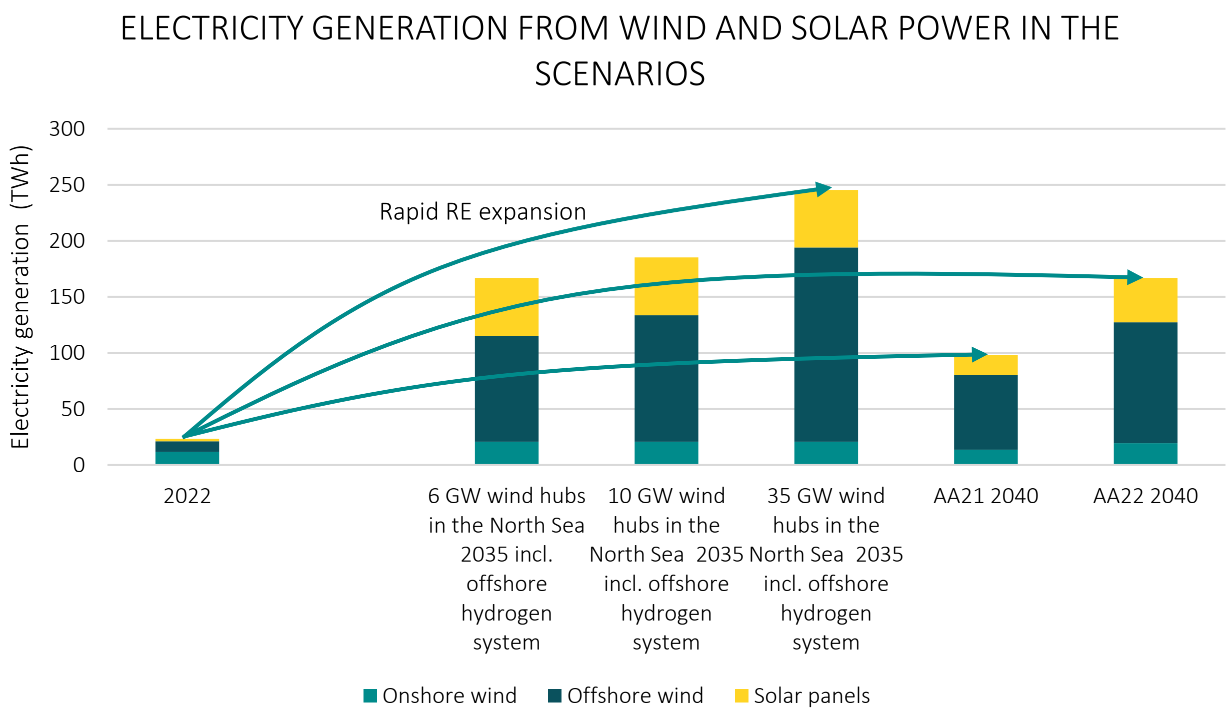

Figure 1:Overview of renewable electricity generation in the analysed scenarios, compared with the analysis assumptions. AA22 (consultation version) is essentially on par with AA21, with the addition of the production described in the Climate agreement on green power and heating of June 2022. Note that the years shown at the bottom vary. '2035+' refers to an unspecified year after 2035.

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In the Danish region of the North Sea alone, there is an estimated potential to establish more than 35 GW of offshore wind power – corresponding to annual production of approx. 160 TWh – using the technology available today. Based on the identified potential, several scenarios have been analysed for the period up until 2035-2040.

The various expansion scenarios are as follows:

- 6 GW wind hub in the North Sea in 2035 and a total of 21 GW of offshore wind power in Denmark (on par with AA22 (consultation version))
- 10 GW wind hub in the North Sea in 2035 and a total of 27 GW offshore wind power in Denmark
- 35 GW offshore wind in the North Sea in 2035+ and a total of 43 GW offshore wind power in Denmark. This is on par with the long-term (2050) high level scenario in AA22 (consultation version).

See further details about the scenarios on page 18.

LARGE WIND POTENTIAL OFFERS VARIOUS DEVELOPMENT PATHS DESCRIBED IN THE SCENARIOS

The vast Danish wind potential gives Denmark great freedom to choose one or more of the following development paths:

- Pilot country for innovation, development and scaling up of advanced high-value PtX applications such as jet fuel, methanol, ammonia etc.
- Centre for new large electricity consuming industries that has the aim of using RE (data centres, chemicals, plastics, steel production and processing, cement etc.)
- Exports of 'raw energy' in the form of electricity and hydrogen.

The analysis operates with several scenarios, and these are not necessarily exclusive. Having large, fixed electricity consumption supplied by wind and solar power offers the potential to further expand these, whereby electricity can be used for PtX during periods when the electricity supply greatly exceeds fixed consumption. The electricity consumption in the analysed scenarios reflects the development potential.

EUROPEAN FRAMEWORK

ENERGY SUPPLY IS LARGELY A JOINT EUROPEAN UNDERTAKING. THE DANISH ELECTRICITY AND GAS INFRASTRUCTURE IS DIRECTLY CONNECTED TO OUR NEIGHBOURING COUNTRIES.

The perspective analysis is based on European scenarios for electricity prices and global prices for ammonia and other advanced PtX fuels as framework conditions. The Danish electricity and gas systems are closely integrated with those in neighbouring countries, and this will potentially be the case long term with the hydrogen system. Prices of electricity, gas and hydrogen in Europe will therefore be of decisive importance to the energy flow and economics of the Danish energy system. Scenarios for development of the European energy system, and thereby prices for electricity, hydrogen and gas, have been based on European scenarios prepared through Energinet's cooperation with the other European TSOs for electricity (ENTSO-E) and gas (ENTSOG). Three main scenarios have been defined: National Trends (NT), Distributed Energy (DE) and Global Ambition (GA).

- National Trends, NT:
  National Trends comprises the various TSOs' best estimates for the development of an energy system which reflects the current national-political initiatives for the transition of the energy sector. The scenario is relatively conservative, particularly in the European context, in relation to the green transition. The EU is not compatible with the Paris Agreement objectives in this scenario either. The scenario is documented in detail and provides the base case in the analysis assumptions. However, since the scenario is quite conservative, more ambitious scenarios (DE and GA) are also used.

- Distributed Energy, DE:
  DE is a scenario where the storyline focuses on greater European energy self-sufficiency and energy efficiency, largely achieved through increased direct electrification. It involves major expansion to offshore wind as well as local solutions such as onshore wind power and PV power plants (both field and rooftop systems). Since it is a goal to reduce energy imports, including gas, the European production of RE gas must be increased. This will be largely achieved using Power-to-X, and the establishment of major electrolysis capacity in Europe.
  A major expansion in renewable energy in Europe will be necessary in order to supply the new electricity consumption.

- Global Ambition, GA:
  GA is a scenario in which Europe continues to extensively use global trade as it develops and decarbonises the energy system. The focus will therefore be on transforming the system by generating renewable energy in Europe at large central plants such as offshore wind power, but there will also be openness to importing more green gases from sources outside the EU. To support rapid and ambitious decarbonisation, nuclear power is retained to a greater extent than in the DE scenario, and CCS is used more extensively to capture and store CO_2 as a means of reducing emissions.

The EU's *REPowerEU* vision recommends an accelerated phase out of the extensive dependence on imported fossil fuels, which the EU is currently dependent on. At the same time, a target of reducing climate gas emissions has been maintained that keeps the EU on track to meet the aims of the Paris Agreement. Of the three scenarios outlined above, the Distributed Energy (DE) scenario comes closest to describing this development path.

The Distributed Energy scenario has been used in this perspective analysis as assumption of the European development.

The ENTSO-E/ENTSOG scenarios have been published in 2020 and 2022 versions. Find more details here: Scenarios – TYNDP (entsoe.eu) /6/. The general analyses use the 2020 version, which has been implemented and analysed in detail in Energinet's analysis system, with updates in May 2022 for fuel and carbon prices.

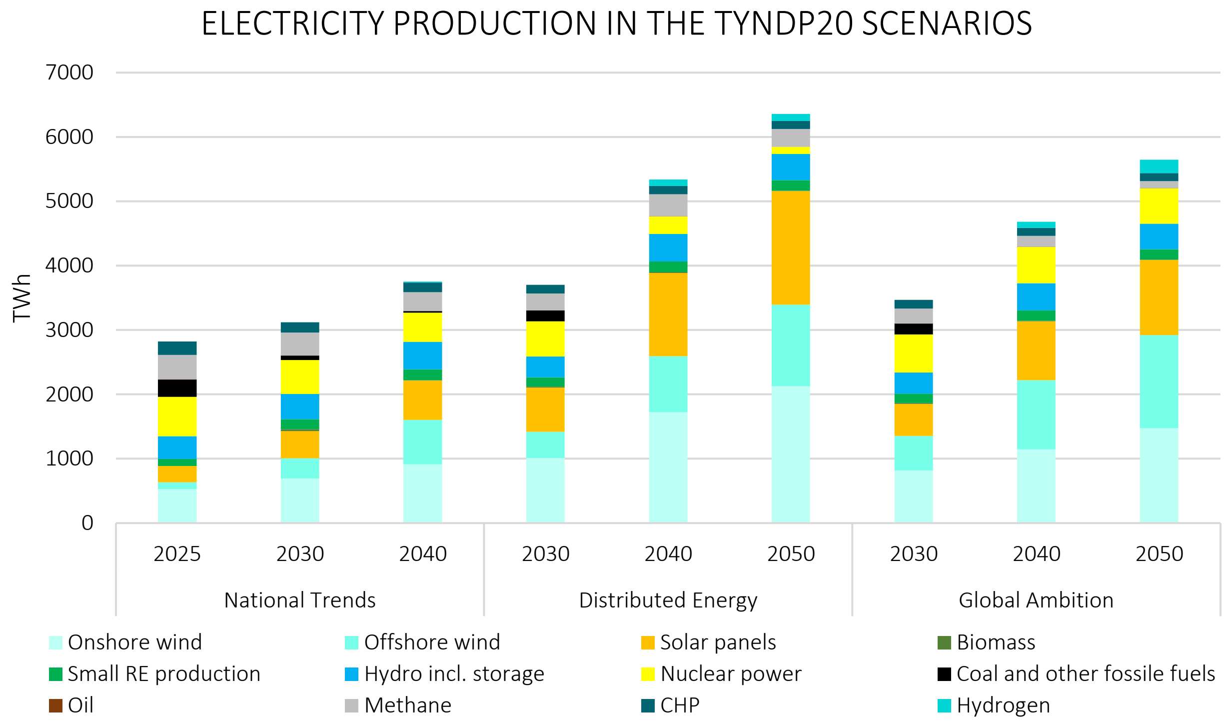

Figure 2: Electricity generation capacity in the three European scenarios in the Ten Year Network Development Plan 2022 (TYNDP22) study. Note that the other calculations in the report primarily use data from TYNDP20.

International prices for PtX products

The ENTSO-E/G scenarios do not consider international prices of PtX fuels such as RE ammonia and RE jet fuel in detail. The exogeneous assumptions for the market value of these products has impact on the value of establishing hydrogen infrastructure. These include the value of hydrogen exported to the European market and of ammonia, methanol, jet fuel etc. exported to the global market. The following assumptions have been used as the base case:

Hydrogen

A price of € 16,8/GJ has been assumed for sale on the international market in 2035. The price is for spot delivery, ie no requirement for a fixed supply. A realised price has also been calculated where a fixed supply of up to 40 TWh annually is required in connection with expansion up to 35 GW offshore in the Danish North Sea region. This calculation makes it possible to optimise investments in hydrogen storage.
Regarding assessment of exports of PtX products, see the Danish Energy Agency's memo, *Export of PtX products* of November 2021.

Ammonia

A price of € 24,9/GJ in 2030 is assumed as the central estimate for the sale of RE-based ammonia. A market price of € 23/GJ is assumed for 2035.

Methanol

Methanol is used in the analysis as a generic green hydrocarbon traded on global markets. The product is used directly on an industrial scale, and can be further refined into jet fuel etc. Production is more expensive than ammonia, as renewable carbon (eg CO_2) is relatively costly. The price typically ranges from € 65-200/tonne, depending on the source, with direct air capture remaining relatively expensive even in the longer term. A central estimate for RE-based CO_2 of € 200/tonne has been assumed. Taking into account the cost of CO_2 feed (eg direct air capture), a market price of € 33/GJ has been assumed for methanol in 2030 and € 31/GJ in 2035.
Ammonia and methanol are both relatively cheap to transport over large distances (sea transport). Production in global 'sweet spots' with both wind and solar power, such as Chile, Argentina and Australia, may therefore have lower prices. Analyses of sensitivities in this area are important in the further analysis.

MODEL IN THE ANALYSIS
(ELABORATED ON THE FOLLOWING PAGE)

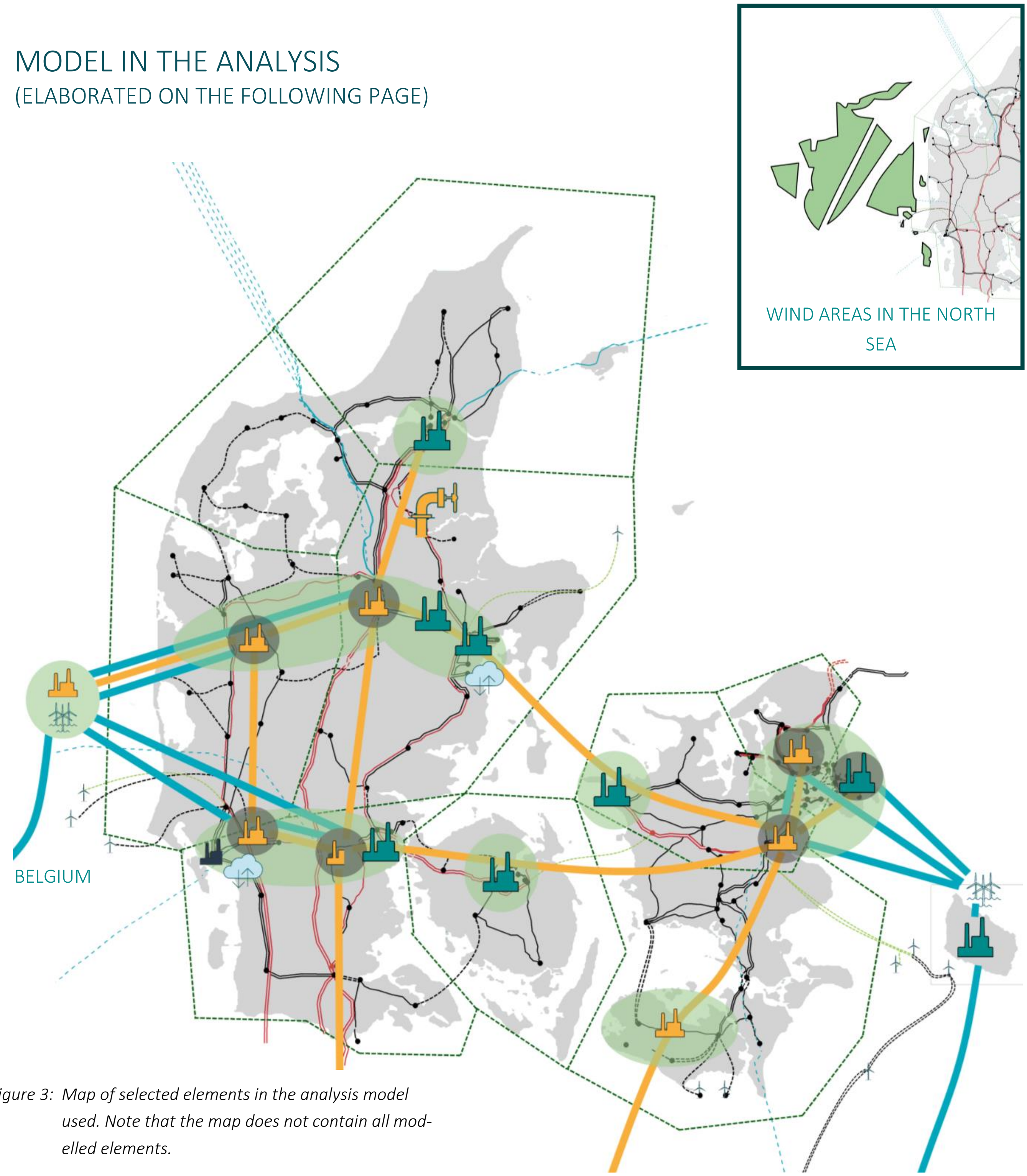

Figure 3: Map of selected elements in the analysis model used. Note that the map does not contain all modelled elements.

ELECTRICITY INFRA-

- Overhead line (150 kV or 132 kV)
- Overhead line (400 kV)
- Overhead line (HVDC)
- Cable (150 kV or 132 kV)
- Cable (220 kV)
- Cable (400 kV)
- Cable (HVDC)

MODEL AREA TYPES

- Zone subdivision
- Offshore infeed
- Co-location zones

Examples of non-illustrated elements:

- 65 heating areas
- Gas areas
- Large-scale batteries

INVESTMENT OPPORTUNITIES

- HVDC connection
- Hydrogen infrastructure
- Hydrogen storage
- Central PtX plant
- Electrolysis plant
- Ammonia plant
- Direct air capture

ANALYSIS MODEL FOR OPTIMISATION ACROSS SECTORS

The analysis is based on an integrated energy system model (SIFRE), where the value chain from energy resources to end consumption for energy services is modelled in a technical and economic operation and investment optimisation. The model operates with plant optimisation based on a market-economy approach. The model contains current plant and consumption based on Analysis Assumptions 2022, and allows investment in a number of different new plants based on a least-cost optimisation of the total energy system costs. The map shows some of the investment opportunities at various locations. Locations and the map are purely illustrative, and should not be interpreted as recommendations for specific locations. The following are examples of elements included in the analysis model:

OFFSHORE WIND ENERGY HUBS in the North Sea and the Baltic Sea (Rønne Bank) with infeed to several possible locations onshore. From the North Sea, for example, as electricity to Revsing and Idomlund, and with the option of offshore electrolysis with a hydrogen infeed to the onshore hydrogen infrastructure. The Baltic Sea hub has possible infeed in the model at Avedøre, Hovegård/Solhøjgård, etc.

CO-LOCATION ZONES are placed at strong electricity nodes, with the aim of providing an incentive for a higher degree of co-location for electricity generation and consumption, such as PtX. In the model, these zones have been established in the Revsing, Endrup, Holstebro, Tjele, Avedøre, Bjæverskov and Hovegård/Solhøjgård areas, and at a number of central power station areas (see the description of PtX plants).

PTX PLANTS are a broad term for electrolysis plants that produce hydrogen, which is used directly, converted into ammonia or further refined into hydrocarbon fuels such as methane, diesel and jet fuel. The model places electrified conversion of biogas into synthetic gas (eSMR) and central PtX plants in co-location zones and in proximity to large primary power stations, eg near Copenhagen, Aalborg, Aarhus, Esbjerg, Fredericia, Odense and Kalundborg. Ammonia synthesis is possible in Esbjerg. Local PtX plants have been modelled where their location matches the physical congestion in the electricity system. Electrolysis has also been analysed at energy islands/hubs.

HYDROGEN INFRASTRUCTURE is modelled between energy clusters, co-location zones and key points in the gas network, with the possibility of a connection to Germany.

HYDROGEN STORAGE using caverns is possible in the area around Tjele/Lille Torup and using steel tanks in connection with central PtX plants in several co-location zones. The model allows the option to invest in a CAES hybrid storage facility with hydrogen in caverns and compressed air in separate caverns.

ELECTRICITY INFRASTRUCTURE based on HVDC and HVAC is an investment option from the energy islands to relevant co-location zones.

ZONE DIVISION for electricity, which are aligned with the physical grid congestion. These zones are used to allow the model to reinforce the infrastructure between zones, and to be able to analyse the flow of electricity indicatively. Offshore wind power is placed in offshore price areas.

BATTERY STORAGE is analysed as large-scale batteries in the various zones. Battery storage allows brief internal congestion in the electricity grid to be handled, and serves as a buffer in connection with fluctuating electricity generation and consumption. Note that the analysis primarily focuses on hourly and annual balances, and therefore does not assess the potential of batteries to provide ancillary services.

HEATING ZONES are modelled for district heating and industrial process heating. It is possible to invest in heat pumps and adapt boilers to hydrogen in these zones. About 65 heat zones have been included to represent district heating networks.

CARBON CAPTURE (CC) plants for the production of hydrocarbon fuels (CCU) or storage (CCS) have been analysed through collection from power stations (biomass/waste), such as Amager 4, Amager Resource Centre (ARC), biogas plants and DAC. There are also plants for collecting CO_2 by upgrading biogas to methane-quality.

DIRECT AIR CAPTURE (DAC) is a technology which can capture CO_2 from the air, and the model places this in the Esbjerg area and near Aarhus.

CARBON STORAGE (CCS) AND TRANSPORTATION will be analysed, with the possibility of storage in the North Sea and modelling transport from local to central areas, whereby zones at Aarhus, Avedøre/Copenhagen and Esbjerg can transport to and deposit in the North Sea. It is assumed that fossil CO_2 from large sources such as Aalborg Portland and refineries can be collected with a view to storage.

WHAT HAPPENS IN A CO-LOCATION ZONE?

Within the various sector coupling areas (see the model overview), a number of activities involving the coupling of electricity, methane, hydrogen and CO_2 have been modelled. The figure below shows sector coupling, modelled onshore and offshore. At sea (hubs), sector coupling consists primarily of hydrogen production by electrolysis. However, a variant with offshore ammonia production has also been analysed. Onshore sector coupling (large yellow box) contains a number of key elements in the sector-coupled energy system.

- Classic biomass CHP with the possibility of carbon capture from flue gas.
- Biogas production (biological) where the biogas subsequently either has CO_2 removed and is fed into the methane grid, or is converted into hydrogen/fuels using electrified reforming (eSMR).
- Thermo-chemical bioconversion using pyrolysis, HtL or gasification, the output of which is nutrients, biochar and gas/bio oil, which can be refined into hydrocarbon fuels.
- eSMR is electrified gas conversion with biogas, methane, hydrogen and CO_2 as inputs, which are converted into synthetic gas (primarily $CO+H_2$), which can be used for the production of various hydrocarbon products.
- Peak-load electricity generation with the possibility of input from biogas, methane or hydrogen.
- Production of ammonia from hydrogen.
- Direct air capture, where CO_2 is collected from atmospheric air. The inputs to this process are process heat and electricity.

The sector coupling solutions are further described in the section on green gas and green carbon.

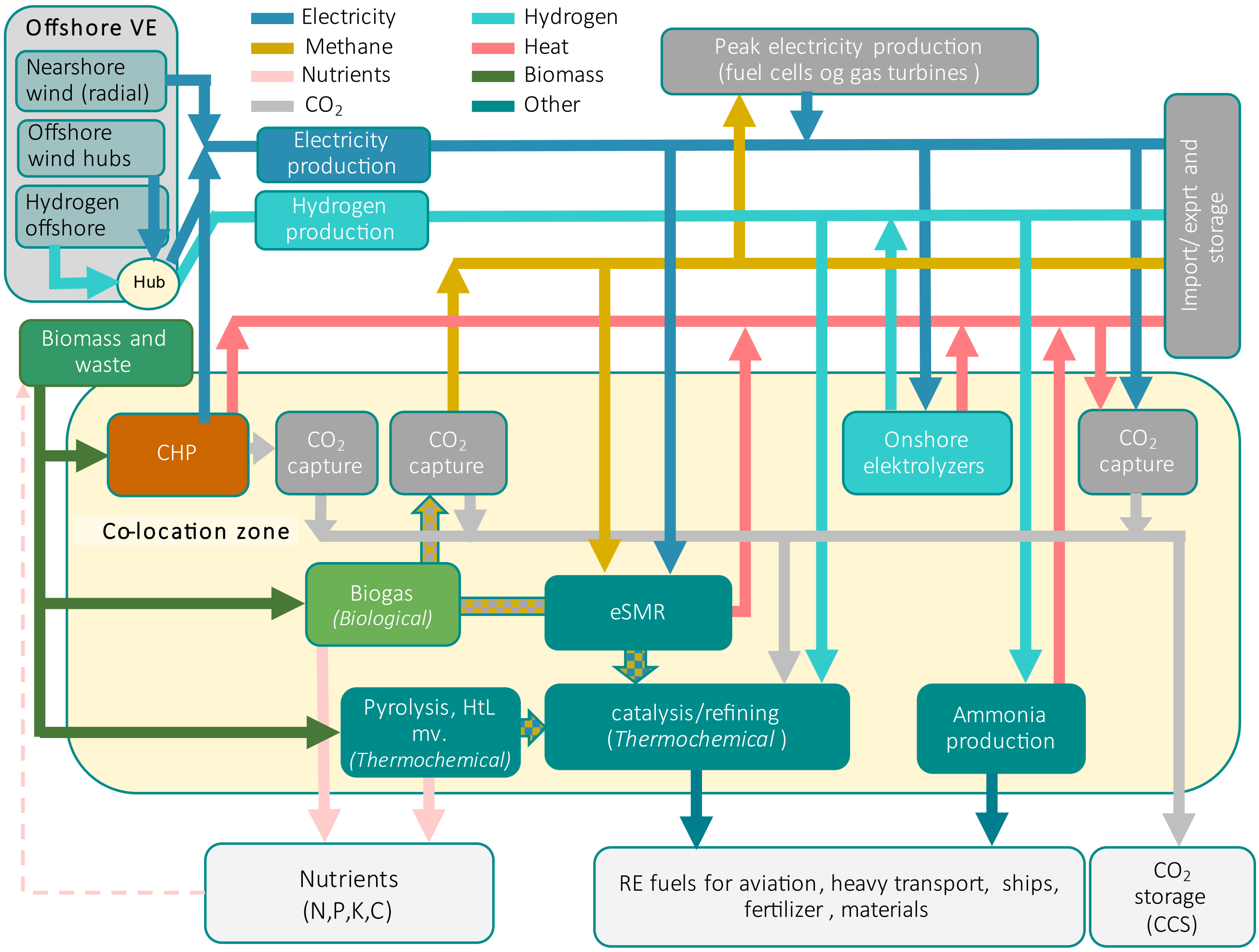

Figure 4: Possible energy flow in one of the model's co-location zones.

HOW IS THE MODEL USED IN THE SCENARIO ANALYSIS?

In the scenario analysis, the model is used to assess how sector coupling can reduce the total system costs by simultaneously using the various infrastructures (electricity, hydrogen, methane, heat, CO_2) to efficiently maximise the value of national RE resources, while achieving the national climate neutrality aims.

The figure below provides an overview of the (exogenous) inputs and the outputs calculated by the model – including overall capacity in electricity and hydrogen infrastructure between sub-zones (see the figure illustrating the model on p. 13), and investment in plant that 'couples' energy between infrastructures. Various scenarios have been analysed with frameworks for investment in infrastructure and utilisation of RE resources such as offshore wind power.

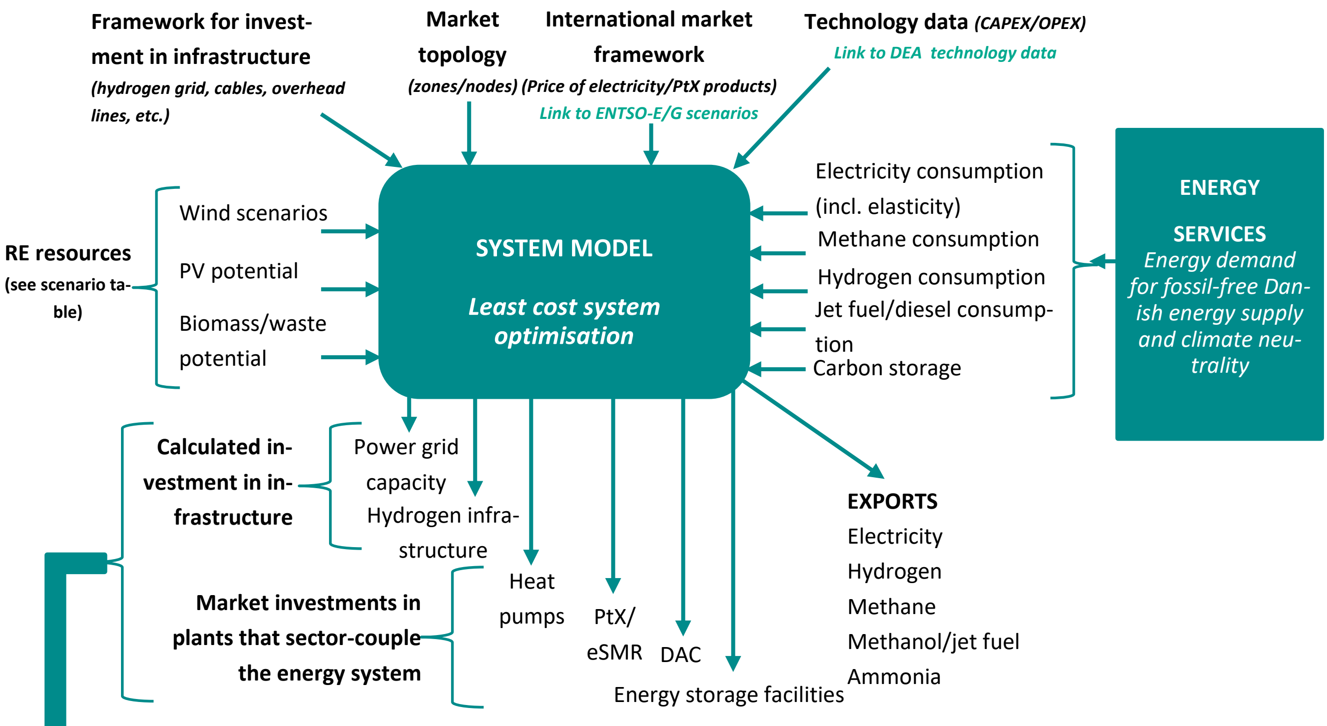

Figure 5: Overview of how the analysis model is used.

EXAMPLES OF INVESTMENTS IN SELECTED SCENARIOS (figures are stated in MW unless stated otherwise)	6 GW wind hub in the North Sea	10 GW wind hubs in the North Sea with offshore hydrogen system	35 GW wind power in the North Sea with offshore hydrogen system
HYDROGEN INFRASTRUCTURE (max. flow)			
North Sea-West Jutland	63	5737	15000
West Jutland-South Jutland	2165	6860	11337
Across South Jutland	2057	5579	11084
South Jutland-Funen	982	3980	2942
North Jutland-Storage at Lille Torup	179	164	159
West Jutland-Storage at Lille Torup	2229	6686	6118
East Jutland-Storage at Lille Torup	871	666	1622
East Jutland-West Zealand	0	0	0
Funen-Central Zealand	0	3021	1883
Central Zealand-Copenhagen	1591	2037	1627
Central Zealand-South Zealand	2392	85	618
PLANTS			
PtX (MW_{H2})	12149	16007	20294
Carbon capture bio-CHP/waste (tonnes/h)	351	351	351
Direct air capture (tonnes/h)	1388	1433	1417
eSMR (MWout)	387	984	714
RE fuels including ammonia (MWout)	4349	4337	4337
Storage H2 (GWh)	800	800	800

Offshore hydrogen production

Offshore and onshore wind and solar cells (PV)

Concept for modelling electricity infrastructure

Hydrogen infrastructure

ANALYSED SCENARIOS

	DESCRIPTION	GENERAL CHARACTERISTICS
2030 70 per cent CO_2 reduction compared to 1990	**2030 REFERENCE SCENARIO** The reference scenario is based on the Danish Energy Agency's Analysis Assumptions for Energinet, with additions reflecting the vision in the 2022 Climate Agreement.	3 GW at Bornholm Classic DK1 and DK2 No hydrogen infrastructure
	2030 HYDROGEN INFRASTRUCTURE IN SOUTHERN JUTLAND Like reference scenario 2030, but with the 'Lower T' hydrogen system connecting Esbjerg-Egtved-Fredericia with a branch from Egtved to Ellund near Germany.	3 GW at Bornholm Classic DK1 and DK2 Lower T
	2030 JUTLAND HYDROGEN INFRASTRUCTURE Like reference scenario 2030, but with the Jutland backbone hydrogen system, where 'Lower T' is connected from Esbjerg along the west coast of Jutland and on to central Jutland, where hydrogen cavern storage is established.	3 GW at Bornholm Classic DK1 and DK2 Jutland backbone
After 2030 Climate neutrality (overall, minus 10 million tonnes CO_2 from the energy sector)	**6 GW WIND HUBS IN THE NORTH SEA** Analyses what an accelerated climate-neutral Danish energy system might look like in around 2035, but using AF22 (consultation version) reference expansion of offshore wind power.	21 GW offshore wind, 7 GW onshore wind & 35 GW PV Market-based Lower T
	10 GW WIND HUBS IN THE NORTH SEA *INCL. OFFSHORE HYDROGEN* High utilisation of Danish North Sea wind potential with 10 GW hub-connected wind power, where electricity and hydrogen are combined in offshore models, plus 2 GW dedicated hydrogen wind turbines.	27 GW offshore wind, 7 GW onshore wind & 35 GW PV Market-based Jutland backbone + offshore Offshore electrolysis
	10 GW WIND HUBS IN THE NORTH SEA *WITHOUT OFFSHORE HYDROGEN SYSTEM* As in the previous scenario, but electricity and hydrogen are not combined in offshore models.	27 GW offshore wind,7 GW onshore wind & 35 GW PV Market-based Jutland backbone
	35 GW WIND HUBS IN THE NORTH SEA *INCL. OFFSHORE HYDROGEN* Very high utilisation of Danish North Sea wind potential with 25 GW hub-connected wind power, where electricity and hydrogen are combined in offshore models, plus 5 GW hydrogen wind turbines.	43 GW offshore wind, 7 GW onshore wind & 35 GW PV Market-based DK backbone + offshore Offshore electrolysis
	35 GW WIND HUBS IN THE NORTH SEA *WITHOUT OFFSHORE HYDROGEN SYSTEM* 25 GW hub-connected wind power in the North Sea, but without offshore hydrogen solutions.	43 GW offshore wind, 7 GW onshore wind & 35 GW PV Market-based DK backbone

ENERGY FLOW IN FUTURE ENERGY SYSTEM

The figure below shows an example energy flow in a scenario with high utilisation of the North Sea offshore resources, with a total of 43 GW offshore wind power, including 25 GW far-shore, 5 GW of which is pure hydrogen wind turbines.

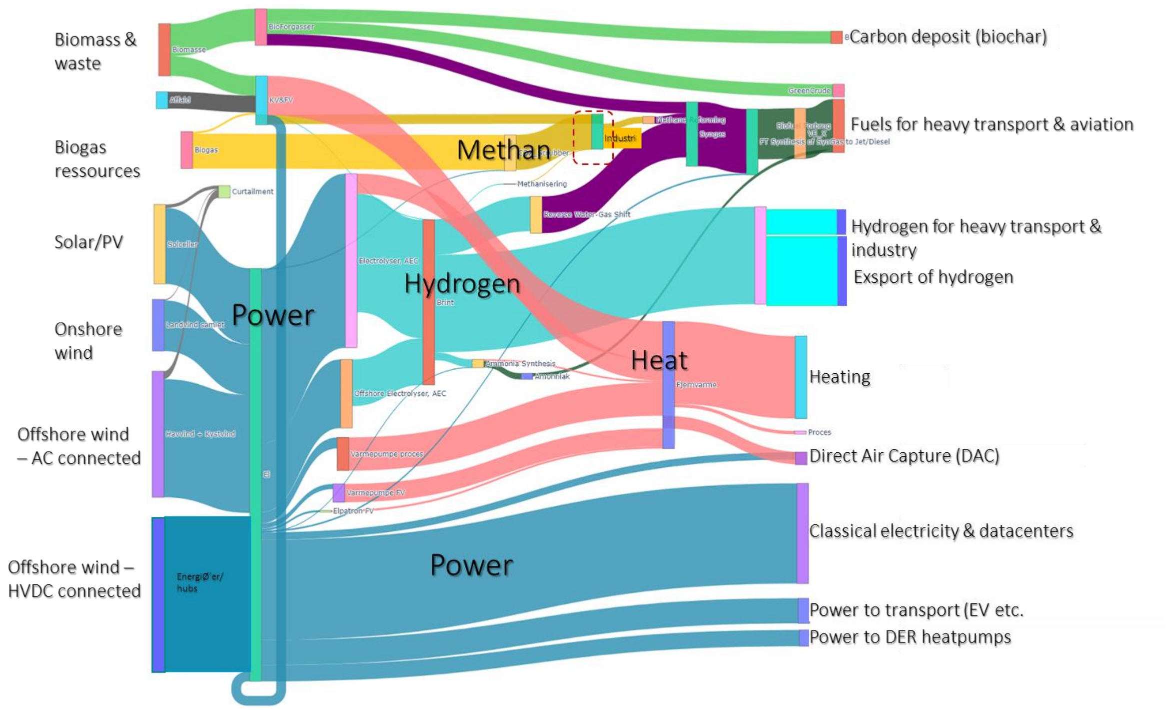

Figure 6: Sankey diagram example of a scenario with 35 GW offshore wind power in the North Sea, including offshore hydrogen system.

GENERAL COMMENTS ON RESULTS FOR SCENARIOS

Electricity and hydrogen will be very large and key energy carriers and interplay is vital. As seen particularly in the scenarios with high wind power expansion, the electricity system will be central to the future energy system. As Figure 6 shows, the hydrogen system will also carry very large amounts of energy. The interplay between the electricity and hydrogen systems will therefore be very central to achieving cost-effective system solutions.

Offshore wind power provides over 75% of total electricity generation in the scenario with the largest expansion of wind power. With 43 GW offshore wind power, 7 GW onshore wind power and up to 35 GW solar (PV) power, renewable electricity generation dominates supply. Offshore wind power dominates annual production due to its high number of full-load hours. Models for the efficient expansion and handling of offshore wind power, including infrastructure, interplay between hydrogen/electricity in offshore solutions etc. will therefore be key to the system costs and competitiveness of Danish wind power in the North Sea (see a further description in the section on offshore models with electricity and hydrogen)

The methane gas system will play a declining and changed role towards 2035. Due to very extensive electrification of heating and industrial process heating, and the fact that CHP plants fired using natural gas will only operate in hours with low electricity generation from wind and solar cells, annual methane consumption will decline. However, the methane system will still play an important role as a backup energy source and for supplying plants which can only be electrified further down the track.
A minor portion of biogas production will be used for the production of jet fuel etc. using electrified gas reforming (eSMR). Depending on the value of exported RE gas (BNG) versus conversion to jet fuel, this relationship may change. Read more about the long-term perspectives for the methane gas system.

ANNUAL BALANCES

Electricity generation and consumption
In the 35 GW scenario, Denmark has enough RE resources to export electricity and hydrogen, and for new electricity-consuming industry. Measured in energy, the generation of renewable electricity here is on par with the average oil and gas production in the North Sea during the 1990-2020 period. With the effective utilisation of this renewable electricity for heat and electricity-based road transport, the high efficiency of electricity solutions could allow the realisation of more than three times the heat and road transport energy services compared to those from oil and gas from the Danish North Sea region during the 'golden age' of offshore oil and gas. The scenarios all result in high offshore wind power generation and significant energy consumption, primarily for electrolysis plants, eSMR and DAC.

Initiatives in the electricity, gas and hydrogen systems will be vital in order to be able to handle such a massive amount of renewable energy. It will be difficult to utilise the large volumes of offshore wind power without good interplay with PtX. Read more about the analysed measures and central system dynamics in the focus areas of the report.

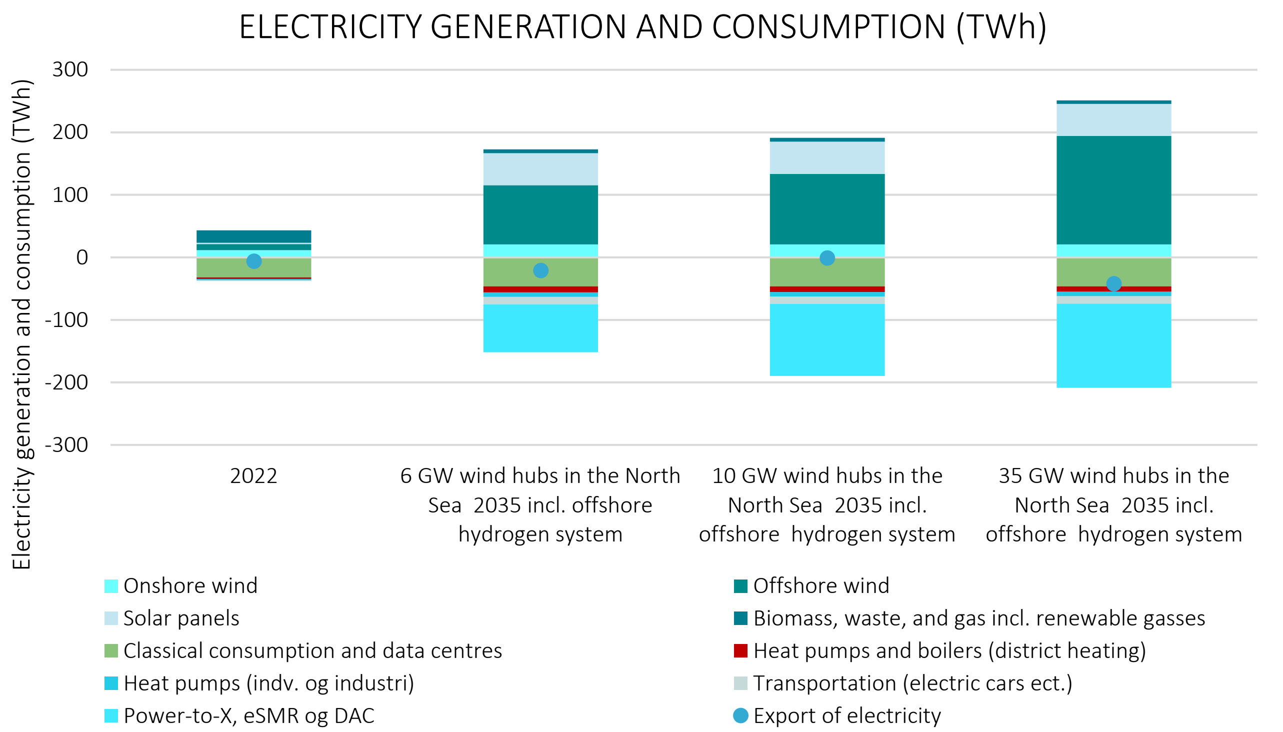

Figure 7: Total electricity consumption and generation shown for all scenarios in the versions with an offshore hydrogen system, compared to AA22 (consultation version) in 2022. The positive figures show production, while the negative figures show consumption.

Hydrogen production and consumption in scenarios
Hydrogen production from renewable electricity is currently extremely limited. Towards 2030, production in the scenarios grows dramatically, in line with the target in the 2022 Climate Agreement of 4-6 GW electrolysis. In the very high RE expansion scenario with 35 GW offshore wind power in the North Sea, total hydrogen production reaches 80 TWh annually. In the scenarios, a significant portion of the hydrogen is refined into liquid fuels and ammonia (PtX activities), and a very large portion of the hydrogen is exported. A small portion of the hydrogen is used directly for heavy road transport. Read more about hydrogen infrastructure to handle these scenarios here.

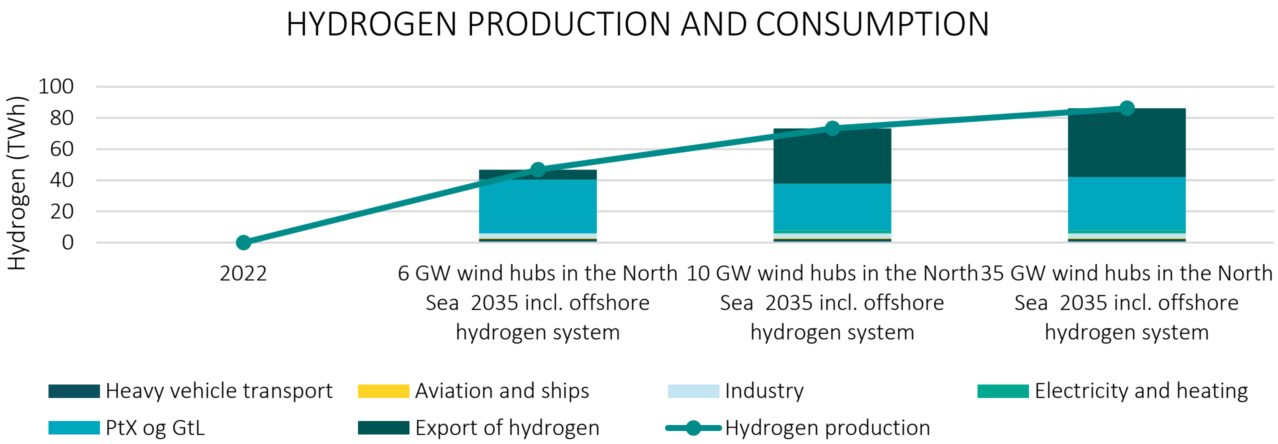

Figure 8: Hydrogen production and consumption shown for all scenarios in the versions with an offshore hydrogen system, compared to AA22 (consultation version) in 2022. Note that several categories contain very small volumes.

Hydrogen production and consumption in scenarios

Natural gas production is unusually low in 2022, as the Tyra field has been temporarily shut down due to maintenance, but will return to production in 2023, so that natural gas production increases again. Towards 2030, biogas production will also rise significantly. It has been assumed that a significant portion of the straw resource will be fed into biogas plants, and the fibre residue used for pyrolysis/gasification/HTL. Overall, renewable (RE) gas production will increase to the point that it exceeds gas consumption for electricity and heating, and for industry and services. It will thus be possible to either export this RE gas or convert some of it to liquid fuels (gas-to-liquid (GtL)).

Gas-to-liquid technology is not included in the Analysis Assumptions or Climate Agreement. Recently developed electrified technology (eSMR) to convert biogas to liquid fuels such as methanol and jet fuel is a potentially cost-effective technology to enable climate neutrality in Denmark, if the production is used nationally, or alternatively exported as high-value jet fuel. With the production of liquid fuels from GtL and from gasification of biomass and hydrogen/CO_2, the ambitious scenarios produce a volume of RE fuels that meets national consumption, incl. international aviation, but not international shipping.

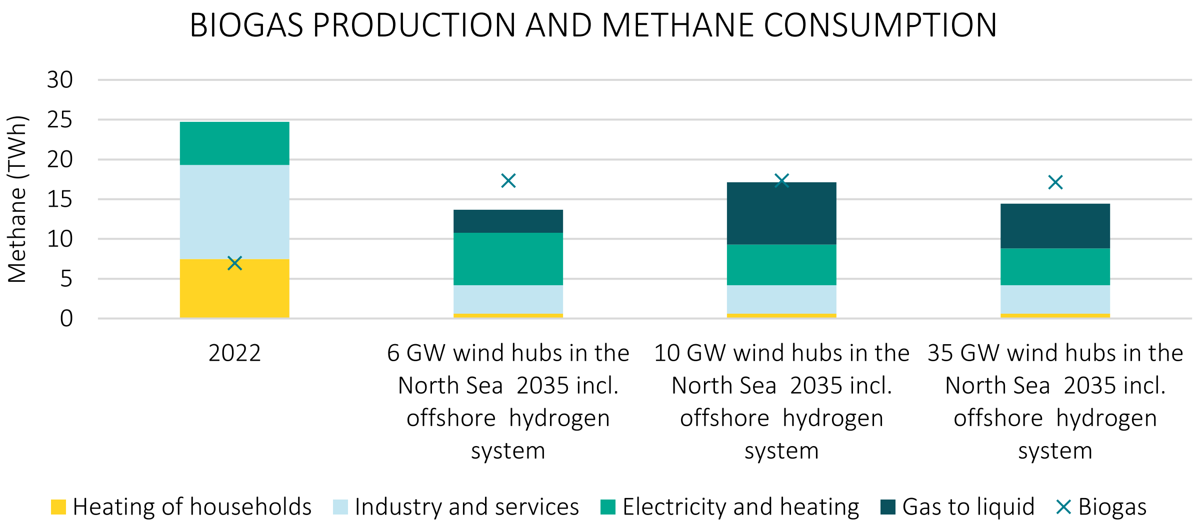

Figure 9: Biogas production and methane consumption shown for all scenarios in the versions with an offshore hydrogen system, compared to AA22 (consultation version) in 2022. Consumption and production in the three future scenarios are constant, as these are limited by the Danish biogas potential.

FOCUS AREAS

The Danish energy system is complex, and there is a wide range of possible outcomes towards 2035. The following sections examine a range of relevant issues and outcomes.

ACROSS ENERGY CARRIERS

- Energy transmission across energy carriers
- Offshore electrolysis may be relevant, but there is a broad range of possible outcomes
- Costs of offshore hydrogen production.

HYDROGEN IN THE ENERGY SYSTEM

- Perspectives for hydrogen infrastructure
- Storage of hydrogen in caverns.

FUTURE POWER SYSTEM

- Analysed interplay between the market and physics in the electricity system
- Use of flexibility as a grid reserve in the system
- Electric vehicles and solar cells take over the suburbs.

GREEN GAS AND GREEN CARBON

- Carbon cycle: PtX in interplay with CCU and CCS
- Long-term perspectives for the natural gas system.

ENERGY TRANSMISSION ACROSS ENERGY CARRIERS

One of the common features in all the analysed scenarios is a greatly increased need to move large volumes of energy around Denmark and to export. In most cases, the mode of transmission is a given – if electricity is generated and is to be used as electricity, it will be moved through the electricity system. It will not be converted back and forth, for example to/from hydrogen, because the energy losses in the process make this too costly, even though hydrogen transport is cheap compared to electricity cables, in EUR/MW/km (see Figure 11). Where power is to be used for hydrogen production, it makes sense to look at how far through the energy system it should remain as electricity before conversion to hydrogen. There is no clear 'right answer'. It is more a question of co-optimising across energy forms and infrastructure types.
Figure 10 shows the model's expansion of electricity and hydrogen capacity for selected sections in different scenarios. In relation to the power grid, the expansion supplements the current expected electricity transmission capacity in 2030, which has been converted into total values for electricity transmission capacity between the zones shown on page 13. The method strongly simplifies the actual power grid, and the results should therefore only be seen as an illustration of different trends across the scenarios. It is assumed that there is no pre-existing hydrogen infrastructure.

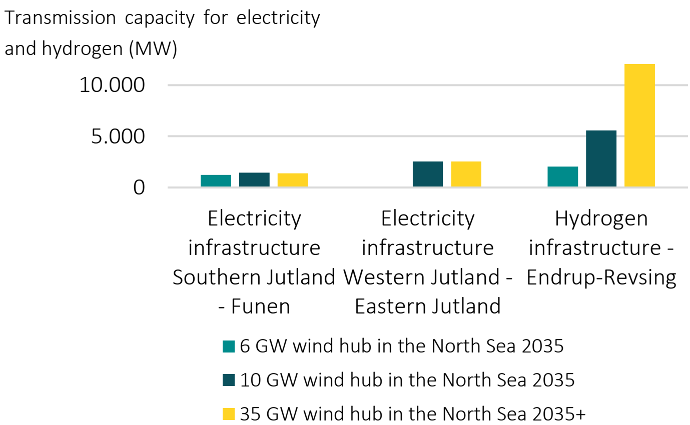

Figure 10: The model allows the possibility of expanding the infrastructure between zones. The expansion is shown here for the sections where there is a major difference between the scenarios. All the scenarios are variants that

The trend is clear for hydrogen infrastructure – to be most cost-effective, the more offshore wind power in the scenarios, the greater the capacity needed for hydrogen infrastructure. Particularly in the scenarios where offshore wind power in the North Sea is expanded to 35 GW (including dedicated hydrogen wind turbines), the need for hydrogen infrastructure from the North Sea and from the onshore electrolysis plants to the hydrogen storage facility in Lille Torup and for exports to European market is high.
Changes in electricity infrastructure vary significantly between the scenarios. There is a need to expand the electricity transmission grid in all scenarios. In the scenarios with a lot of offshore wind power, more energy is transmitted as hydrogen, and the operational flexibility of the electrolysis plants is used to get the most out of the existing electricity infrastructure.

The scenarios generally assume that the power grid will be reinforced using underground cables. A sensitivity analysis will be conducted where expansion using overhead lines is an investment possibility. Technical challenges involved in operation of high AC-voltage underground cables have not been fully accounted for. In general, cables are markedly more expensive per kWh transmitted than overhead lines, while the cost of hydrogen infrastructure is estimated to be the same level as for overhead lines (see Figure 11, which shows unit costs for infrastructure for various technologies and energy types).

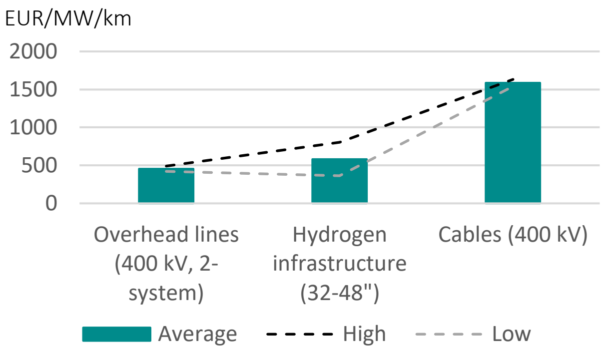

Figure 11: Estimated costs of infrastructure expansion. Note that the different types of infrastructure transmit different forms of energy, and that the costs do not include conversion losses.

OFFSHORE ELECTROLYSIS MAY BE RELEVANT, BUT THERE IS A BROAD RANGE OF POSSIBLE OUTCOMES

A significant portion of the electricity generated from offshore wind power is expected to be converted into hydrogen. Where this conversion of electricity into hydrogen (electrolysis) takes place will be key to the infrastructure need. Electrolysis can essentially take place in three places: 1) onshore, eg near the landing point/sector coupling zone, 2) offshore on platforms/islands or 3) directly in the wind turbines. One factor is that it is more expensive to move offshore energy onshore using electricity infrastructure than it is using hydrogen infrastructure. At the same time, it is more expensive to produce hydrogen at sea, and power brought ashore for direct electrification also has value. The optimal solution will therefore depend on several factors, such as:

- Distance from offshore wind turbines/hubs to shore
- Cost of electrolysis plants, including offshore foundations
- Value of power brought ashore
- Value of hydrogen brought ashore

There are considerable uncertainties about the cost of electrolysis at sea, so this must be investigated further. Preliminary assessments indicate that if only hydrogen is to be produced from the area with wind hubs (80 km from shore), offshore electrolysis in dedicated hydrogen wind turbines is the most cost-effective solution. The uncertainties regarding the costs of producing hydrogen on platforms are considerable. This solution makes it possible to bring part of the capacity ashore as electricity, and let offshore electrolysis use the electricity that it is not cost-effective to bring ashore as electricity.

With a central estimate for the value of hydrogen brought ashore at EUR 2.00-2.50/kg, electrolysis at sea in hydrogen wind turbines would be cost-effective. Given the massive need for hydrogen in Europe, electrolysis may prove very relevant in the deployment of wind hubs in the North Sea. Up until 2030, offshore electrolysis is assumed to still be in the development stage, but is a potential alternative longer term to bringing energy ashore as electricity and using a large portion for electrolysis at the landing point.

The hybrid models involving offshore electrolysis will make it possible to optimise utilisation of the relatively expensive HVDC capacity from hub to shore. The analysis for 2035 has optimised for the deployment of offshore electrolysis, and HVDC and hydrogen transmission to the landing point. The capacity of pure hydrogen wind turbines has been exogenously fixed.

The relationship between capacity brought ashore and offshore electrolysis is very sensitive to the realised prices for hydrogen and electricity. Figure 12 shows the simulated cases with offshore hydrogen wind turbines, electrolysis at the hub and electrolysis onshore. Figure 13 on the following page shows estimated costs of hydrogen production (LCOH). In this model, the entire production is converted to hydrogen.

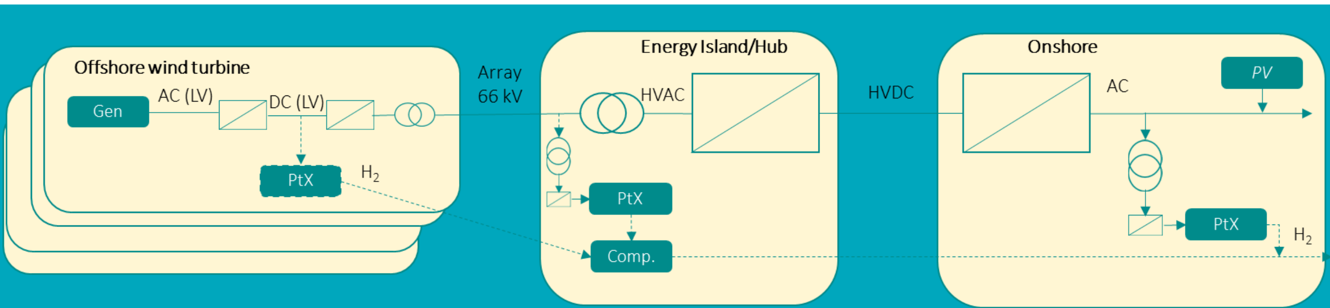

Figure 12: Analysed offshore models. To the left, the figure shows the energy from offshore wind turbines either being converted to AC or converted directly from DC to hydrogen. At the energy hub/island/collection point, production from the wind turbines is either collected as electricity in an HVDC cable, or converted to hydrogen and compressed before being brought ashore. Onshore, the electricity is transmitted inland or converted to hydrogen. If hydrogen is received onshore from the hub, it is fed into the land-based infrastructure.

If offshore electrolysis is to be matured, plans to deploy offshore hydrogen infrastructure with a collection point in the North Sea need to be made fairly quickly. It will be a strategic choice whether offshore hydrogen from the Danish North Sea region is routed to Denmark, or connected to hydrogen infrastructure routed to Europe, for example via the Netherlands.

Cost of offshore hydrogen production

Figure 13 shows the estimated costs of producing hydrogen exclusively from offshore wind in different configurations. For wind turbines relatively close to shore (less than 50 km), electrolysis onshore is the cheapest way to produce hydrogen from offshore wind power. For far-shore wind turbines, the cheapest way to produce hydrogen is to install pure hydrogen wind turbines. However, this removes the flexibility to either supply to the electricity grid or produce hydrogen.

For far-shore hybrid solutions (both electricity and hydrogen), foundation costs will have to be low for it to be relevant to do the electrolysis offshore. Otherwise it will be cheaper to bring electricity ashore and do flexible electrolysis there. The analyses show that if the costs of foundations etc. for electrolysis can be kept low, offshore electrolysis can be cost-effective. As areas are brought into play further offshore, the use of pure hydrogen wind turbines may gradually become the best option. In connection with screening onshore hydrogen infrastructure, offshore hydrogen strings could also be screened as part of a holistic model.

The costs of these models entail considerable uncertainties, and it is important to do further detailed studies of both hybrid models (hubs) and dedicated hydrogen wind turbines. This includes in development projects such as 'Offshore Energy Hubs', the 'Balthub project' and the 'North Sea Wind Power Hub' cooperation.

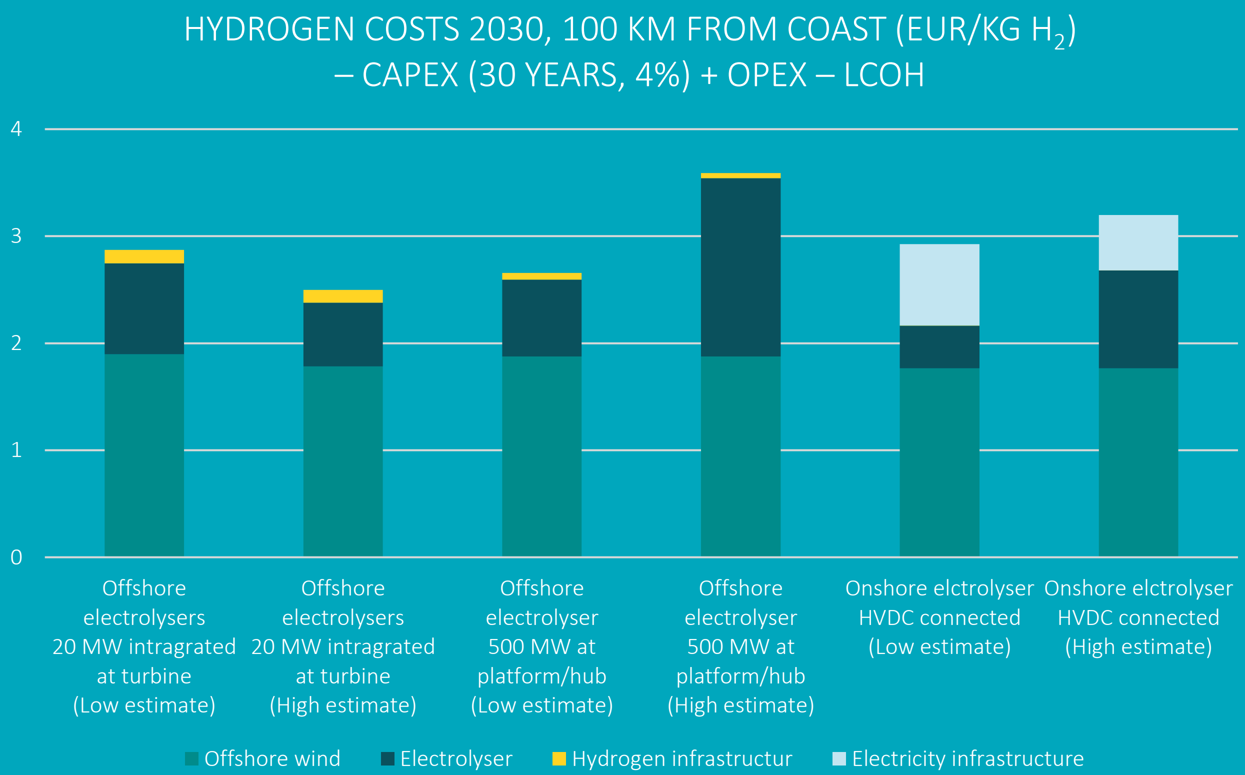

Figure 13: Costs linked to offshore models analysed. Note that the figure only shows the hydrogen production price, and does not include factors like extra income from the sale of electricity in the models connected to shore. Note the use of Danish number separator.

PERSPECTIVES FOR HYDROGEN INFRASTRUCTURE

The value of hydrogen infrastructure has been analysed separately in various scenarios, both in a 2030 context and moving on towards climate neutrality and large-scale utilisation of the Danish offshore wind power potential. Hydrogen infrastructure is a key element in ensuring a robust energy system that can exploit the Danish renewable energy potential on a very large scale. The analyses show that by combining hydrogen infrastructure with various other measures, very extensive RE expansion can be handled without prohibitively large investments in electricity infrastructure. Various expansion scenarios have been analysed:

West Denmark (Jutland/Funen):

1. Lower T (Esbjerg-Egtved/Ellund-Triangle Region)
2. Jutland Backbone – there is a hydrogen link between Lower T via the west coast to a hydrogen storage facility at Lille Torup
3. Extended backbone – like option 2, but with expansion to Odense, Aalborg, Hirtshals and Hanstholm
4. Backbone and North Sea – like option 3, but with expansion to the Danish energy island in the North Sea.

East Denmark (Zealand, Lolland/Falster):
Establishment of a connection from the northern region of Copenhagen (Hovegård) down across Zealand (Bjæverskov) and Lolland/Falster (Radsted) to Germany (Rostock).

Connection between East and West Denmark:
With the establishment of Baltic Pipe, there is a double pipeline connection for methane across Funen and South Zealand. The capacity has been sold under a long-term contract until 2038. There could, in principle, be available capacity after that, such that one of the pipes could be upgraded for hydrogen transmission.

As part of the 'European hydrogen backbone' study, perspectives on the connection between Jutland and Sweden have been assessed. A connection from Gothenburg to Lille Torup or Aalborg, or from Malmö to Copenhagen, may become relevant here.

Figure 14: The figure shows hydrogen infrastructure, analysed in relation expansion to 35 GW offshore wind in the North Sea.
As part of the *European hydrogen backbone* study, perspectives on the connection between Jutland and Sweden have been assessed. A connection from Gothenburg to Lille Torup or Aalborg, or from Malmö to Copenhagen, may become relevant here. This element has not been included in the analysis.
Similarly, offshore hydrogen could potentially be connected directly to Germany or the Netherlands. These elements are marked by dotted lines on the map.

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The analyses indicate that with the vision in the *Climate agreement for green electricity and heat 2022*, hydrogen infrastructure as outlined in the 'Lower T' and 'Jutland Backbone' scenarios is a cost-effective initiative. System analyses indicate that establishing a Jutland backbone already becomes cost-effective towards 2030.

Infrastructure costs are based on indicative figures, and more detailed studies must be carried out before a firm conclusion can be reached. Further studies must also analyse the flow in the hydrogen infrastructure and storage in relation to operation of a possible hydrogen storage facility at Lille Torup.

Energinet launched a hydrogen feasibility study in summer 2022 that aims to provide a basis for proceeding to assess the establishment of hydrogen infrastructure in Denmark and more precisely estimate the costs.

The long-term scenario (35 GW offshore in the North Sea) analyses expansion involving the Jutland backbone, a connection from an energy hub in the North Sea to Jutland, and a connection across Funen to a Zealand 'backbone' with Hovegård-Copenhagen-Lolland-Germany. See examples of flows in parts of the hydrogen infrastructure in Figure 15.

The major offshore wind power potential in the North Sea leads to a very high load on central parts of a Jutland backbone (see Figure 15). The connection across Funen and the 'backbone' on Zealand will be less heavily loaded. However, greater interplay with Sweden, in line with the European Hydrogen Backbone, and greater expansion of offshore wind power in the Baltic Sea region could significantly change the flow in the Zealand backbone.

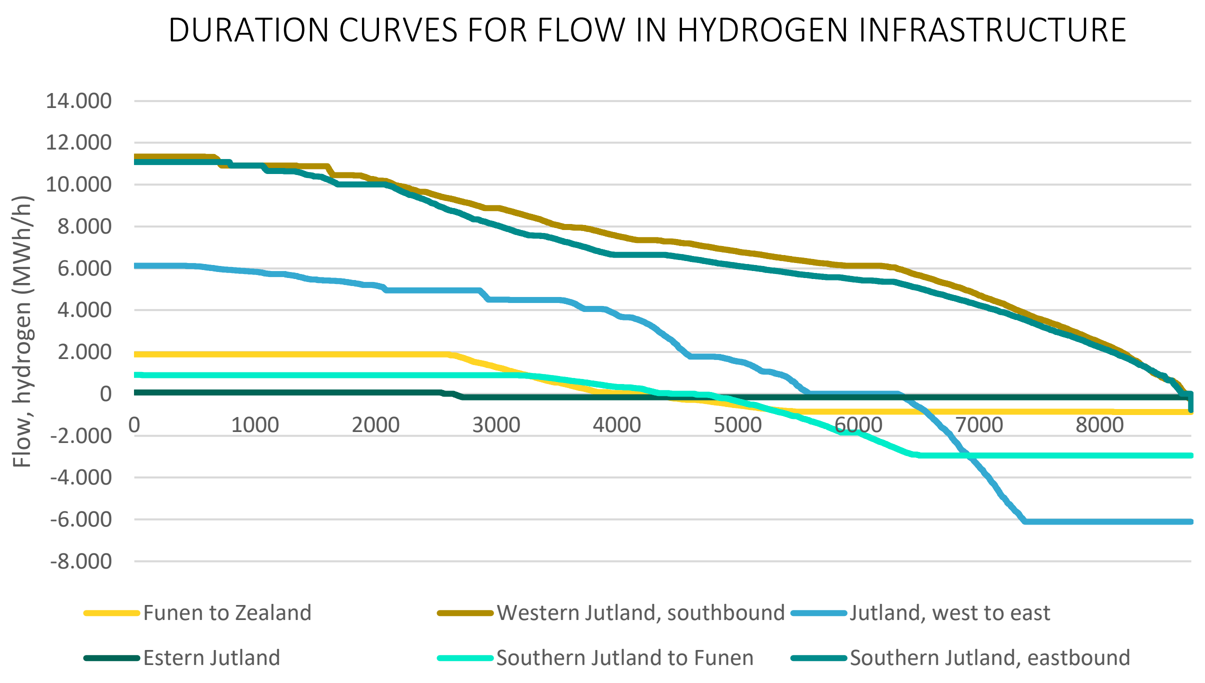

Figure 15: Duration curves for flow in sections of the hydrogen infrastructure for the scenario with 35 GW offshore wind in the North Sea.

INTERACTIONS BETWEEN HYDROGEN PRODUCTION AND HYDROGEN STORAGE

Investments in storage capacity (energy content) and capacity for feeding into the storage facilities have been optimised in the model. Analyses have been done for cavern storage at Lille Torup and steel tanks at the Revsing and Copenhagen nodes. Linepack storage in pipes has also been exploited, whereby changing the pressure in the pipe creates a storage function in the pipe itself. The storage facility ensures that plants using hydrogen have a stable supply, even though the electrolysis plants operate flexibly and thus have uneven hydrogen production. The storage level in the cavern storage is shown in Figure 16. In this scenario, the storage facility typically has 8-10 filling cycles over a year.

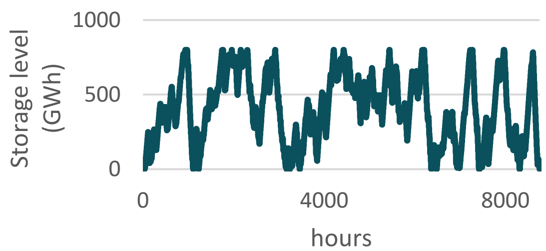

Figure 16: Storage level in the hydrogen cavern storage facility in the scenario with 35 GW offshore wind power in the North Sea and an offshore hydrogen system.

Figure 17 shows hydrogen transmission capacity as a function of the pipeline diameter at different pressure levels. A 36" pipe with the possibility of compression can handle the transmission of up to 8-10 GW hydrogen. In the scenario with 35 GW of offshore wind power in the North Sea, hydrogen production will be so high (see Figure 15) that pipeline dimensions higher than 36" will be needed if all the hydrogen is brought ashore. However, if production from dedicated hydrogen wind turbines (5 GW) is led to the Netherlands, for example, 36" pipes could potentially cover this scenario.

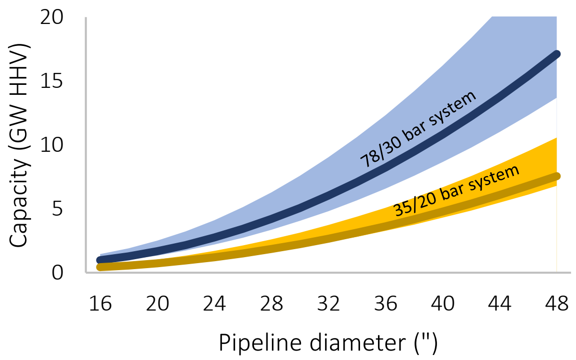

Figure 17: Transmission capacity in hydrogen pipes of various diameters.

Operation of electrolysis plants

In the system analysis, the hydrogen market is operated as an hourly market, during hours in which the market value of hydrogen relative to the electricity price justifies operation. There are typically 2,500-4,000 annual hours of operation (see the duration curve for a year in Figure 18).

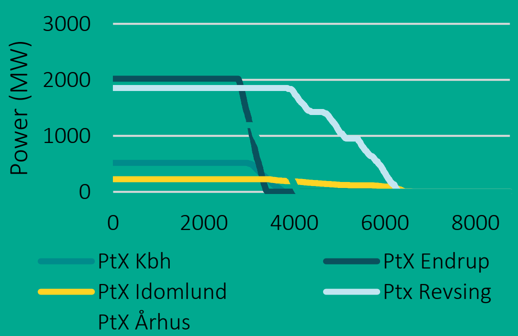

Figure 18: Duration curves for key electrolysis plants in the scenario with 10 GW offshore wind power in the North Sea and an offshore hydrogen system.

Flexible operation over a month (January) can be seen in Figure 19. The electrolysis plant contributes a high degree of flexibility to the electricity system. Regarding the hydrogen system, feed-in and extraction also take place at points here in relation to the hourly market.

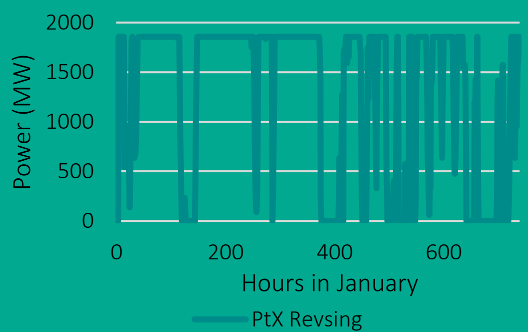

Figure 19: Example operation for a central electrolysis plant in January, in the scenario with 10 GW offshore wind power in the North Sea and an offshore hydrogen system.

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Pressure and flow simulations have been performed for given pipe dimensions. Quite extensive analyses of flow, compression and system operation are needed. The figure below shows an example of flow and pressure in pipes from the North Sea via a west coast connection and Lower T to Germany. The fluctuating production of hydrogen and – in this example – fluctuating consumption, lead to significant pressure variations in the hydrogen infrastructure. Figure 20 shows system operation without a compressor, but where hydrogen can be fed in from offshore electrolysis at up to 50 bar.

Pressure at Ellund (German border) varies considerably in the example due to fluctuating production, but a change to the operating strategy could improve these conditions significantly and must be further investigated. In special cases, it may therefore be necessary to provide ancillary services to the hydrogen grid from specific electrolysis plants and storage facilities. This could lead to system operation initiatives that affect both the electricity system and the hydrogen system. This will require system operation with a real-time overview of the electricity and hydrogen systems, to ensure the most appropriate ancillary services are activated.

In relation to offshore development, it is a strategic choice whether to connect hydrogen production in the North Sea with Danish infrastructure and/or with the Netherlands or another country. Preliminary calculations indicate that high aims for the expansion of wind power in the Danish North Sea region and the deployment of electrolysis plants make it relevant economically to have both the hydrogen infrastructure backbone on land and the connection to offshore hydrogen production.

GRADUAL EXPANSION OF HYDROGEN INFRASTRUCTURE

Variations in the analysis show that up until 2030, there is significant value in establishing a Jutland backbone and a North Jutland hydrogen cluster with a storage facility at Lille Torup.
In East Denmark, there is a basis for hydrogen clusters near Copenhagen and South Zealand/Lolland/Falster.

Thereafter, towards 2035, the establishment of an offshore hydrogen connection may be cost-effective if offshore electrolysis technology develops favourably.

This would make Denmark a relatively strong 'bridgehead' for the Danish North Sea energy sector, whereby growth in the energy industry can be brought into play. With hydrogen infrastructure to Germany, Denmark is at the feed-in point, but if there is surplus hydrogen, Germany can – in line with the ENTSO-E TYNDP22 scenarios – import volumes that far exceed the Danish production potential.

EXAMPLES OF PRESSURE AT SUBSTATIONS IN THE NORTH SEA-IDUMLUND-ENDRUP-EGTVED-ELLUND HYDROGEN INFRASTRUCTURE

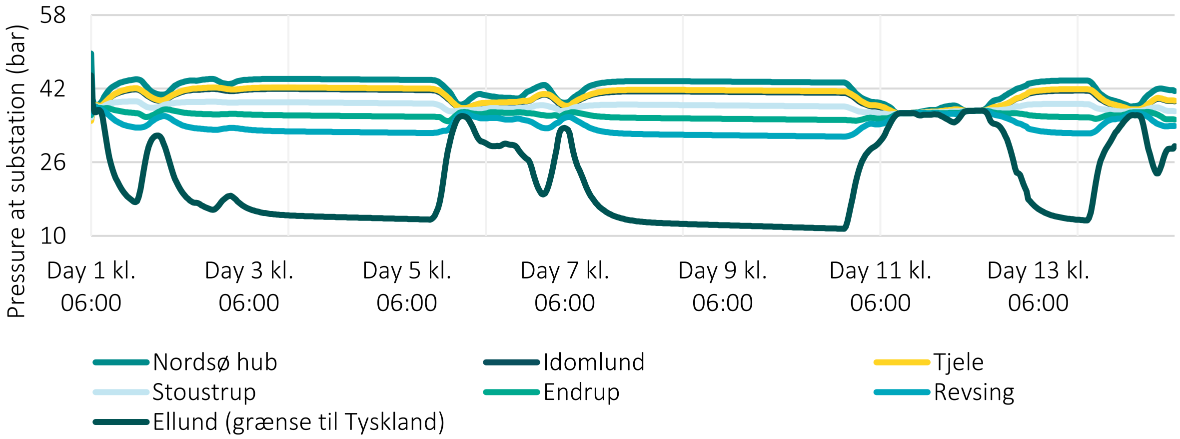


Figure 20: Example of pressure at various locations in a simulated hydrogen infrastructure in Jutland.

INTERPLAY BETWEEN VARIOUS TYPES OF ENERGY STORAGE

Closer coupling between energy systems makes it possible to exploit the strengths of the various energy carriers. Storage costs vary, and connecting the energy systems together offers cheaper access to flexibility than, for example, if the power system can only use direct electricity storage such as batteries. The figure below shows the cost of storing a given type of energy using various technologies.

Note that conversion between energy forms typically involves considerable losses. For example, storing electricity in batteries may be cost-effective if it is for a short time and the energy is to be used as electricity.

By offering access to different types of storage capacity, sector coupling leads to significant flexibility, and investment in storage capacity helps to balance fluctuating electricity generation. Primarily the expansion of hydrogen storage facilities adds storage flexibility over days and weeks. There is significant uncertainty about storage in electric vehicles with respect to availability, and this has only been estimated based on the number of electric vehicles and access to up to 30 kWh per battery.
This is very small energy capacity compared to hydrogen and gas storage facilities, but offers a considerable power reserve for short-term power regulation (hours).

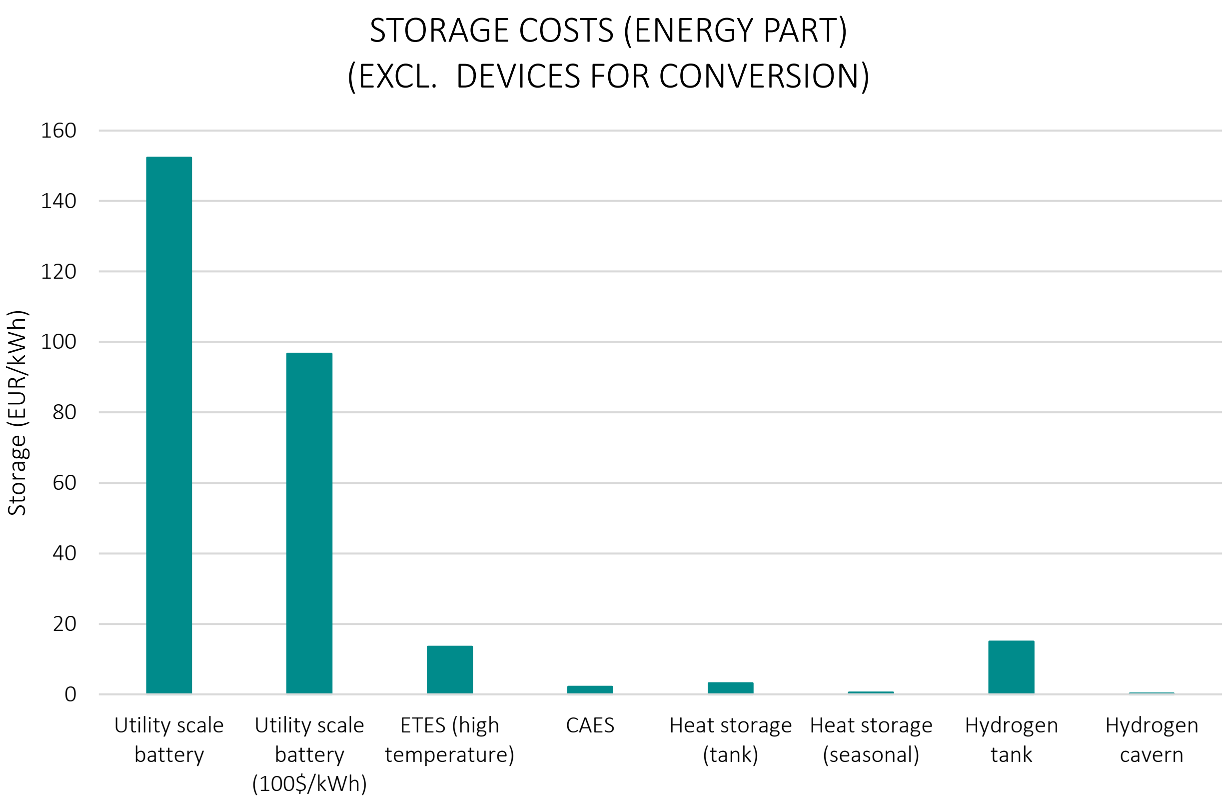


Figure 21: Investment costs for various types of storage.

Hydrogen, methane and liquid fuels might become the dominant large-scale stores of energy for balancing variations over days/weeks and seasons. The highly fluctuating electricity generation from wind and solar cells is largely balanced by PtX plants being operated flexibly in the scenarios. Since end consumption of energy services is relatively inflexible, the necessary flexibility must be achieved through sector coupling, whereby large amounts of energy can be stored in the system. Storage of chemical energy from hydrogen, methane and liquid fuels will be crucial.
Battery capacity for large-scale storage sees only limited expansion from the 6 GW North Sea hub to the scenario with 35 GW offshore wind in the North Sea.

A maximum capacity of 800 GWh for conversion of methane caverns has been assumed. In scenarios with a fixed supply of hydrogen to Germany, the model invests in the full capacity. PtX plants deliver flexibility for intraday variations, as well as variations over weeks/months (see the figure showing operation of hydrogen storage facilities).

In addition to converting caverns to hydrogen, it may be relevant to invest in establishing new hydrogen caverns. This element has not been studied here.

The expansion of battery storage may be considerably larger due to the increasing need to handle internal congestion in the power grid, also at DSO level, and to provide ancillary services to the electricity system.

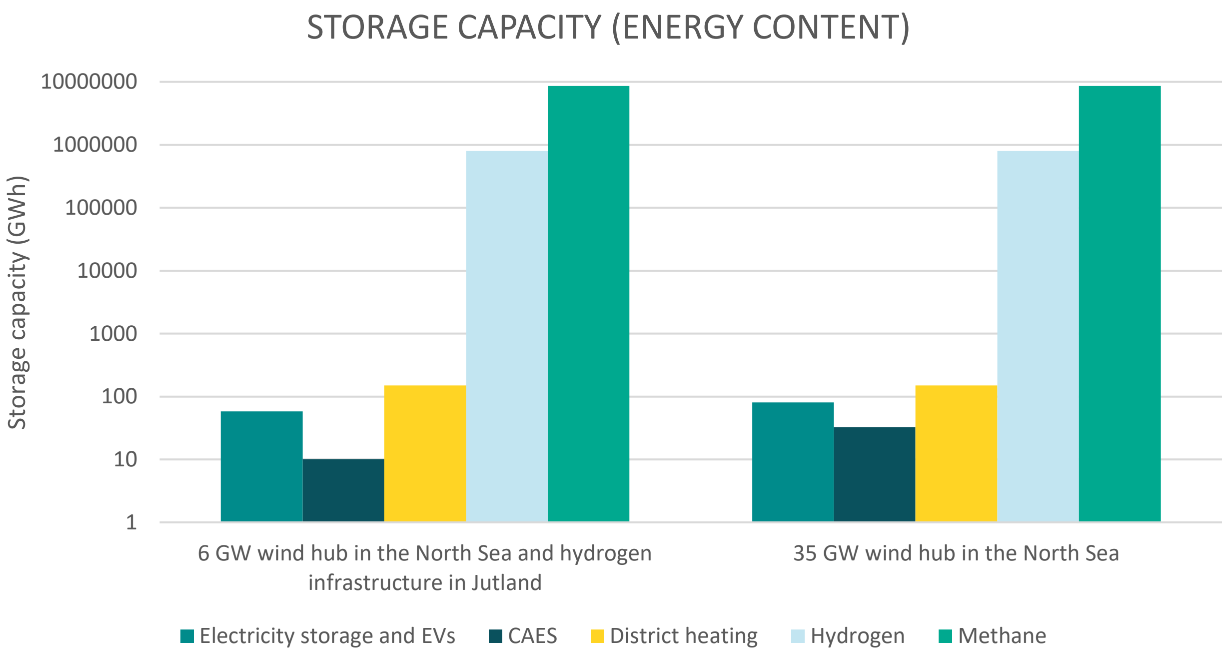


Figure 22: Energy content in storage facilities simulated in the model for the scenario with 35 GW offshore wind power in the North Sea and an offshore hydrogen system. Note that the y-axis has a logarithmic scale. For district heating, storage directly connected to large solar heating plants is not shown.

ANALYSED INTERPLAY BETWEEN THE MARKET AND PHYSICS IN THE SYSTEM

With more wind and solar power, PtX and general electrification with electric vehicles, heat pumps etc., the risk of internal congestion in the TSO grid increases. It is possible to reinforce the power grid either using cables (relatively expensive) or overhead lines (politically problematic) to eliminate congestion.

Greater sector coupling, whereby energy is transferred to other energy carriers, such as hydrogen, can reduce congestion in the electricity grid relatively efficiently. This will require incentives to place and operate RE and PtX plants optimally in relation to infrastructure capacity. Market initiatives that reflect the physical infrastructure capacity will be effective tools for ensuring optimal placement and operation of plants. The analysis shows that with market solutions that optimise operation and investment incentives that reflect the physical congestion in infrastructure, a major expansion in renewable energy can be handled in the energy system.

In the EU, ACER is working to establish long-term market solutions which reflect physical conditions far more closely than the current price areas. They are well aware that implementing these could lead to challenges and considerable political resistance, so this is seen more as a long-term initiative. For example, with smaller price areas, there is a risk that an RE producer might receive a lower market price than would be the case with the large price areas.
Local regulating power bids (bids with a geographic location) can be used to handle internal congestion in the power grid, but there may be a risk of speculation from having different geographical resolution in the regulating power and day-ahead markets. For example, if an electricity producer bids in the day-ahead market and is activated and paid the price area price, but is then ramped down due to internal congestion via local regulating power bids.

The long-term development of the electricity market is taking place in a broad European context, and precise outcomes are difficult to predict. In the long term, planning can be based on a trend towards finer geographical resolution, while in the short term, national measures can be used to handle internal grid congestion. These include geographical regulating power bids, limited grid access, direct lines established by market participants, and capacity maps showing players where there are good conditions for placing new consumption and production. Investment incentives can also be reasonably ensured using geographically differentiated tariffs. The current initiatives in this direction are explained in material available on Energinet's website.

Given the possible long-term expectation of finer geographical divisions, it is a focus point that RE and PtX tenders over the coming years must be compatible with this. There are solutions for ensuring robust RE prices, eg hedging against larger price zones. Some countries outside the EU, in particular in US, have strong competencies in nodal pricing. International innovation and inspiration can thus inspire within market solutions for a renewable energy dominated system. Figure 23 shows areas in which dramatic RE expansion typically leads to congestion in electricity grid capacity. These sub-zones have been used in the analysis model, but this should not be taken as an indication of future

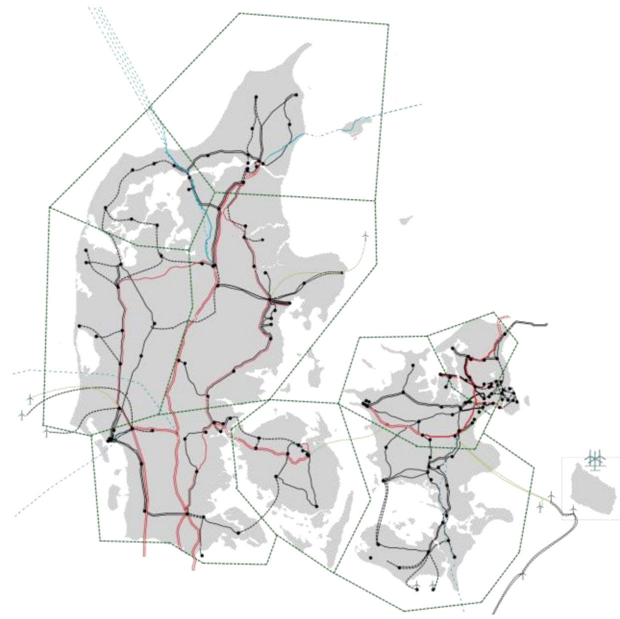
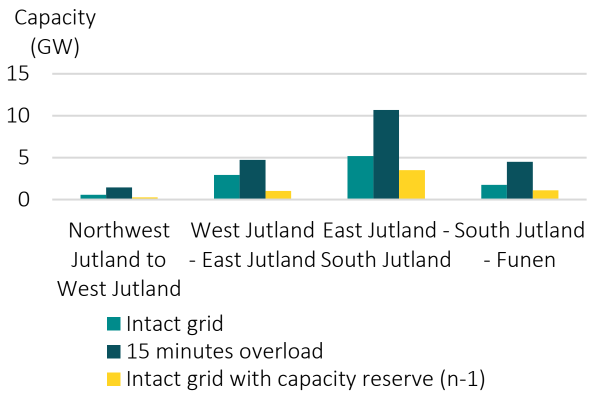


Figure 23: The dotted lines show the areas the model has been subdivided into. Please note that this does not reflect future market zones.

USING FLEXIBLE ELECTRICITY CONSUMPTION AS A SUPPLEMENTARY GRID RESERVE

The electricity system is currently operated under the premise that electricity consumption should still be met even if an incident occurs in the power grid. This places considerable demands on the volume of grid reserves with available capacity to handle an outage. This therefore often limits full utilisation of the electricity transmission grid.



With rising volumes of dispatchable consumption,

Figure 24: Grid capacity in selected sections in 2030 with an intact grid, 15-minute overload permitted, and an intact grid with capacity reserved to handle one critical fault (n-1).

there is potential to develop models that allow demand facility flexibility to be utilised to reduce the need for available grid capacity. This requires that consumption and production can be adjusted symmetrically, and in the case of a grid fault, on either side of the fault. If production and consumption are not ramped down symmetrically around congestion in the electricity grid, this will result in an imbalance, which will be forced across AC interconnections (to Germany in DK1 and Sweden in DK2).
The analysis shows that there is considerable potential in realising these opportunities and using demand-side response actively.

The physical flow follows the impedances in the AC grid. It is therefore not assured that capacity which is thermally possible can actually be exploited. The actual load flow can be assessed in more detail in a simulation using the Power Factory tool as a supplement to the base model of the analysis.

Work is already being done to develop tools which can increase the utilisation of the electricity infrastructure. For example, the 'Limited grid access' product, where it must be possible to disconnect consumption within 15 minutes, has come a long way in its development. This is the first step towards using demand-side response as a supplementary grid reserve.
If consumption will be ramped down within a 15-minute period, some overload can be permitted until consumption has been ramped down. Figure 24 shows capacity with an intact grid and a brief 15-minute overload, with/without n-1 considerations.

Figure 25 shows an example simulating the flow between the West Jutland and South Jutland sub-zones, with 10 GW offshore hubs in the North Sea and at different grid capacities: 1) with an intact grid with the possibility of reinforcement using underground cables between sub-zones and 2) assuming that there are no network constraints.

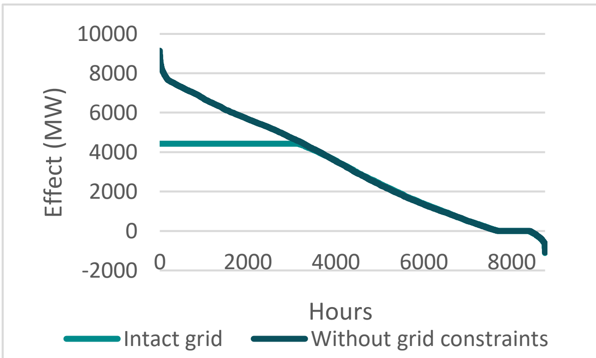


Figure 25: Example duration curve for the flow between areas in West Jutland and South Jutland. The figure shows a case where the model has the full thermal capacity available for optimisation, and a case where transmission capacity is limited.
The figures are from the scenario with 10 GW wind hubs in the North Sea and an offshore hydrogen system.

STABILITY IN AN ELECTRICITY SYSTEM DOMINATED BY WIND/PV/PTX

Central power stations have generally been a key element in gridforming capability, ensuring stability in the electricity system by providing inertia, voltage control and short-circuit power. In step with the massive expansion of wind power and solar cells, the need for generation from power stations is declining. Electricity generation from wind power and PV power plants is connected via power electronics, and does not naturally provide gridforming capability with the properties required to maintain power system stability like a central power station does. However, work is ongoing to develop ways to control plants connected by power electronics, so that they can to some extent provide properties required to maintain power system stability.

Figure 26 shows wind and solar power generation relative to power station production for the scenario with expansion up to 35 GW of offshore wind power in the Danish North Sea region. Electricity generation from thermal power stations is very limited compared to wind/solar power generation. Demand-side response from PtX, heat pumps, electric vehicles and batteries represents a significant dispatchable resource most of the time there is high wind/solar power generation.
In Denmark, heat generation has been an important revenue base for the central power stations, and has provided an incentive for them to continue operating during hours with relatively low electricity prices. But heat production from PtX related activities and large heat pumps will meet much of the district heating needs in the central power station areas.

Stability in a system with almost 100% generation and consumption from plants connected by power electronics is therefore a core challenge that must be addressed. This could be, for example, by gradually phasing in wind and solar generation that provides dynamic voltage support and inertia response etc., that matches the response provided by traditional synchronous generators (grid forming) to the extent this is useful. See the research cooperation at national and international level (ENTSO-E /6/, G-PST/8/) for more information.

MORE IMBALANCES FROM WIND, BUT MORE FLEXIBILITY FOR BALANCING

With the increasing proportion of wind and solar power, there is a greater imbalance between the forecast and realised renewable electricity generation during the delivery hour. The 'CorRES' simulation tool developed by the Technical University of Denmark was used to analyse the difference between the forecast and realised offshore wind power generation. Figure 27 shows these differences between forecast and realised production for the scenario with a 6 GW offshore energy island/hub in the Danish North Sea region. The figure shows the day-ahead and hour-ahead imbalances as duration curves and the distribution throughout the year.

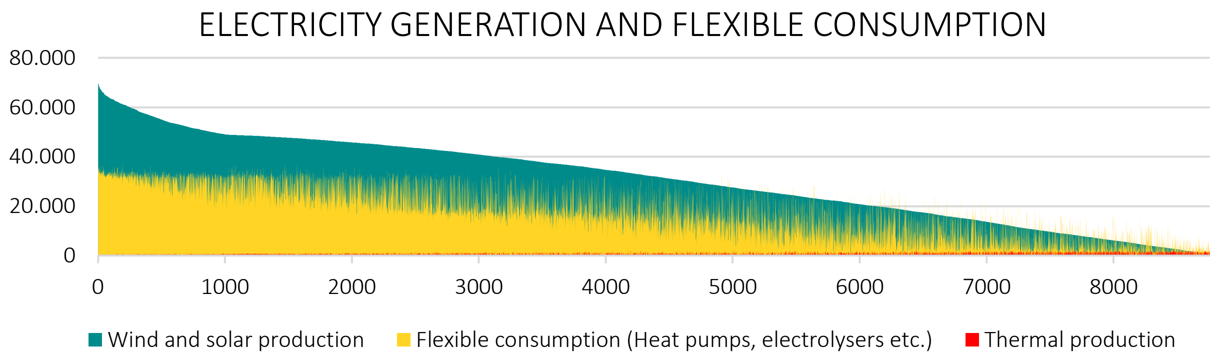


Figure 26: Hourly data for thermal production capacity, generation from wind turbines and solar cells, and flexible consumption. Data is from the scenario with 35 GW of offshore wind power in the North Sea.

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With the expansion of wind and solar power generation, there is a simultaneous expansion in partially or fully flexible consumption in the form of electric vehicles, heat pumps of various sizes and electric boilers, Power-to-X etc. Figure 28 shows the hour-ahead forecast error (y-axis) as a function of calculated flexible consumption during the same delivery hour (x-axis). During hours when **more generation** than expected is realised (positive y values, light green marking), the situation can be handled by increasing electricity consumption (if possible) or ramping down electricity generation from wind power as necessary. This situation is thus not critical from a security of supply perspective.

During hours where **less generation** than expected is realised, flexible consumption can potentially be ramped down and thereby address the imbalance. In other words, during hours where flexible consumption is higher than the forecast error (yellow marking), the imbalance can be handled if (and only if) the demand-side response can be activated during the delivery hour. Hours where flexible consumption is higher than forecast errors can thus potentially be handled by ramping down the flexible electricity consumption. It should be noted that Power-to-X may have other obligations, eg technical limitations or requirements to deliver hydrogen, if there is no access to hydrogen storage.

Unless there is flexible consumption that can handle the imbalance, production will have to be ramped up from thermal electricity generation or battery storage to handle the imbalance. However, as shown in Figure 28 (red marking), it is only for a small number of hours that this situation arises. This is typically when there is moderate wind power generation and high electricity prices, and flexible electricity consumption has therefore not been activated. The figure here is simply for illustration, and shows only imbalances from offshore wind. Imbalances from onshore wind and solar power, locations of flexibility etc. also come into play.

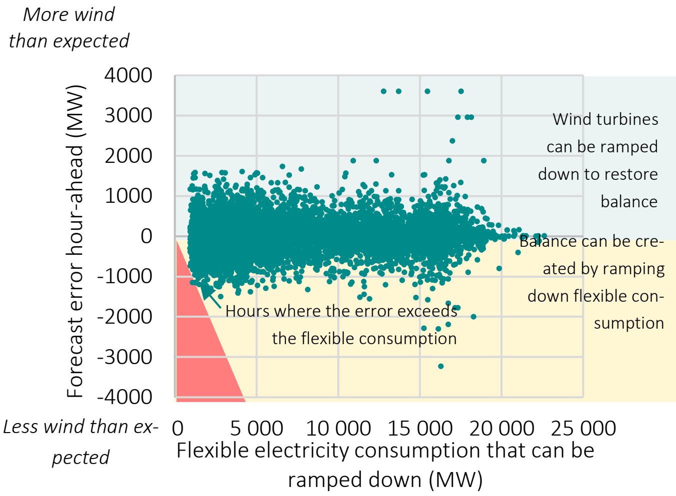


Figure 28: Relationship between forecast errors the hour before the delivery hour and potentially flexible consumption for the given hour. Each point represents one hour. Data is from the scenario with 6 GW of offshore wind power in the North Sea.

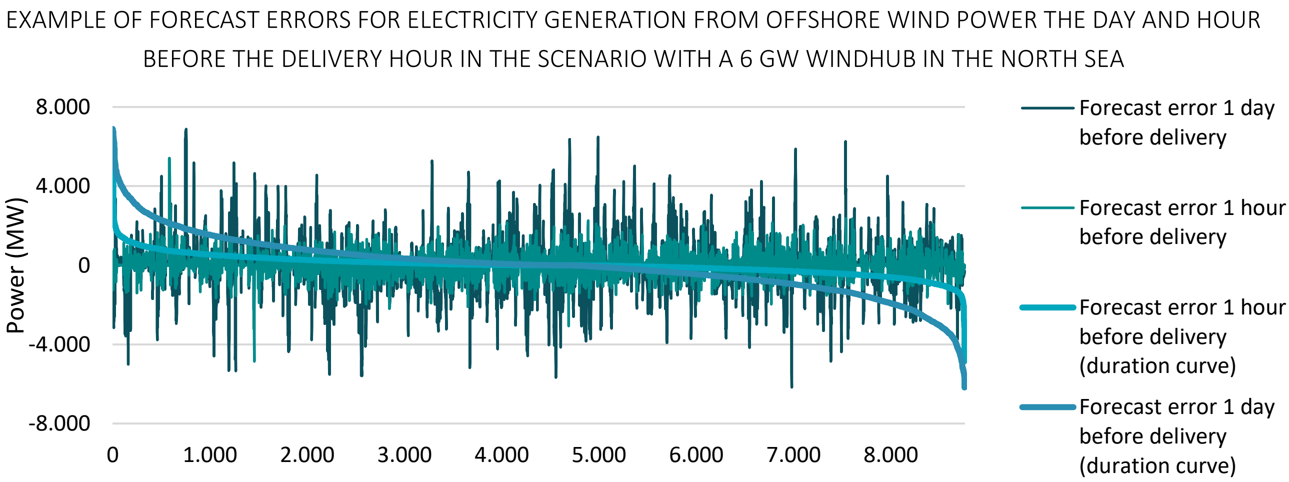


Figure 27: Errors in the forecasts one day/one hour ahead of offshore wind power generation in the scenario with a 6 GW offshore wind power energy island/hub in the North Sea.

ELECTRIC VEHICLES AND SOLAR CELLS TAKE OVER THE SUBURBS, CALLING FOR CO-OPTIMISATION OF THE ELECTRICITY TRANSMISSION AND DISTRIBUTION GRIDS

As a vital element of the green transition, passenger transport will be electrified by more widespread use of electric vehicles and using heat pumps for heating. At the same time, the number of small-scale solar cell plants is expected to increase. Increased electricity consumption and generation will change the way the distribution grid is used. There is a risk of situations arising in which capacity in the existing electricity grid is insufficient.

Charging electric vehicles, in particular, is expected to create a significant challenge. The number of electric vehicles currently in use is still limited (approx. 100,000 purely electric vehicles), and optimisation of charging to prices on the electricity market is also limited. As charging is adapted to take place in hours with low electricity prices as far as possible, the risk of overloading the distribution grid increases.

This analysis assumes that a model is developed which ensures that private electric vehicles are charged when electricity is as cheap as possible for the consumer, without causing inconvenience. The same is assumed for private heat pumps. To avoid modelling situations where the distribution grid can be overloaded, capacity is limited to a simplified, realistic level, and the simulation ensures that all electric vehicles are charged as cheaply as possible without overloading the power grid.

The challenge is being seen all over Europe, and in cooperation between TSOs, DSOs, market players and knowledge institutions, model solutions are being developed, tested and implemented that handle congestion locally in the electricity system, while also providing an incentive to use electricity in periods with plentiful wind and solar power generation.

Energinet performs analyses and experiments involving interplay between real-time prices, ancillary services, new types of electricity consumption and local congestion handling measures, and cooperates actively with market participants.

WHO WANTS TO CHARGE THEIR ELECTRIC VEHICLE WHILE POWER IS EXPENSIVE?

The figure shows a typical situation on a suburban street/0.4 kV branch with 10 houses from the analysis. It is based on electricity market prices for the 2030 reference scenario. The analysis assumes one electric vehicle per household, and solar cell deployment is based on the most cost-effective level. The figure shows that for approx. 8% of the hours during the year, capacity on the branch is pushed to its limits due to the overlapping charging of electric vehicles in hours with low electricity prices. It is therefore vital that the interplay between the electricity markets and the DSO electricity grid is developed in the coming years.

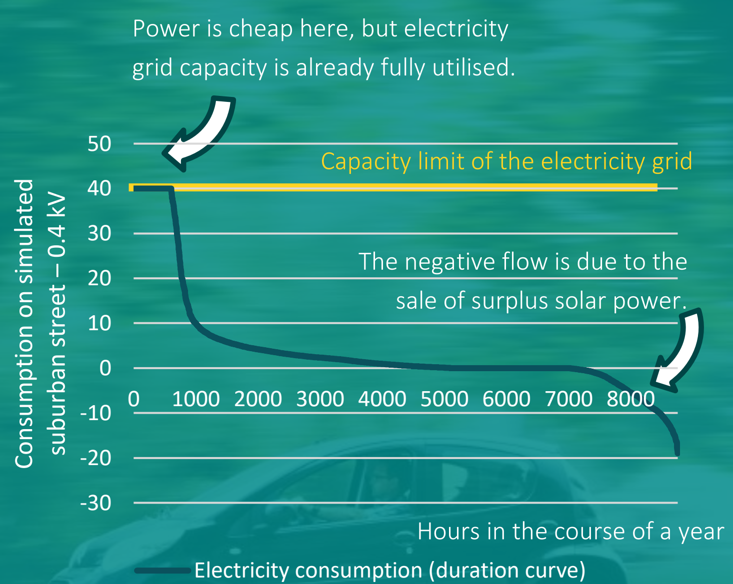


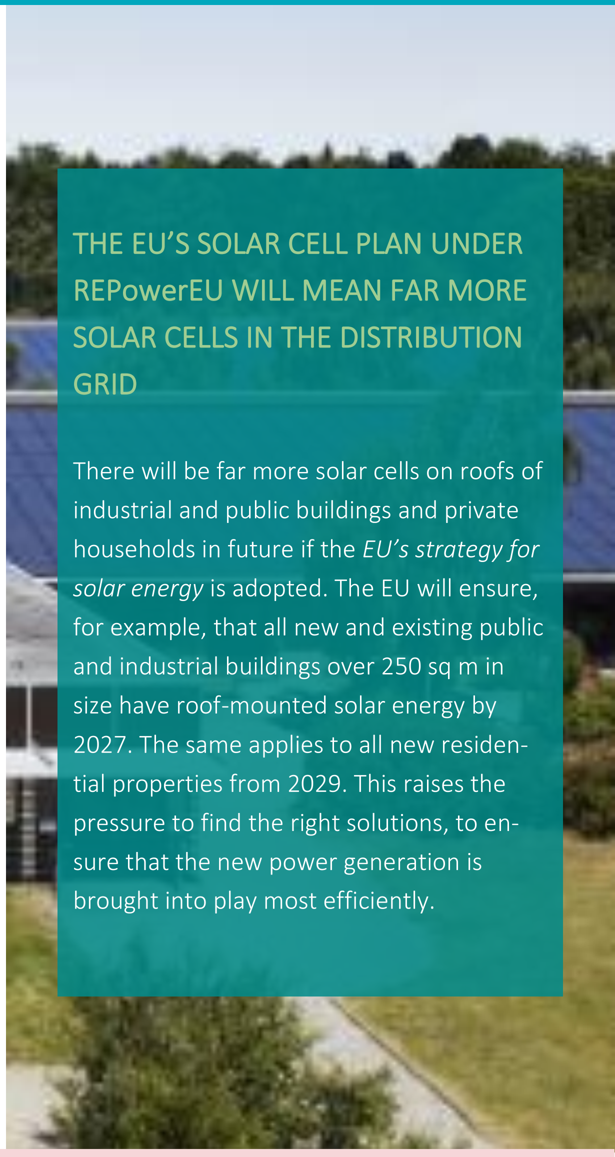
Figure 29: Example of simulated load on a 0.4 kV branch on a suburban street with electric vehicles, solar cells and batteries.

HOW WILL THE INTERFACE BETWEEN ELECTRIC VEHICLES AND THE ELECTRICITY MARKET BE?

The transition to electric vehicles is creating new and very close ties between the transport and electricity sectors. The dynamics between the sectors, which are handled in this analysis with a simple optimisation, are actually complex and rapidly changing. The roll-out of electric vehicles and charging stations is accelerating, and the ecosystem spanning from electricity generation to electric vehicle drivers is a hot topic everywhere, from the EU level down to the dinner table.

The *Vehicle Grid Integration Research* report, commissioned from Rethinking Energy by Energinet, identifies current dynamics and business models in the ecosystem and core problems and solution paths for developing an ecosystem that ensures electric vehicles become an active player in the energy system. Results include a model for *social and responsible charging*, shown in the figure at the bottom of the page.

The report highlights, for example, that one of the core elements in a smoothly functioning model will be to develop the right framework for electric vehicle owners to allow a third party to communicate directly with either the electric vehicle or the charging station, so that digital signals can be sent to control how the electric vehicle is charged. Read more in the report here.



THE EU'S SOLAR CELL PLAN UNDER REPowerEU WILL MEAN FAR MORE SOLAR CELLS IN THE DISTRIBUTION GRID

There will be far more solar cells on roofs of industrial and public buildings and private households in future if the *EU's strategy for solar energy* is adopted. The EU will ensure, for example, that all new and existing public and industrial buildings over 250 sq m in size have roof-mounted solar energy by 2027. The same applies to all new residential properties from 2029. This raises the pressure to find the right solutions, to ensure that the new power generation is brought into play most efficiently.

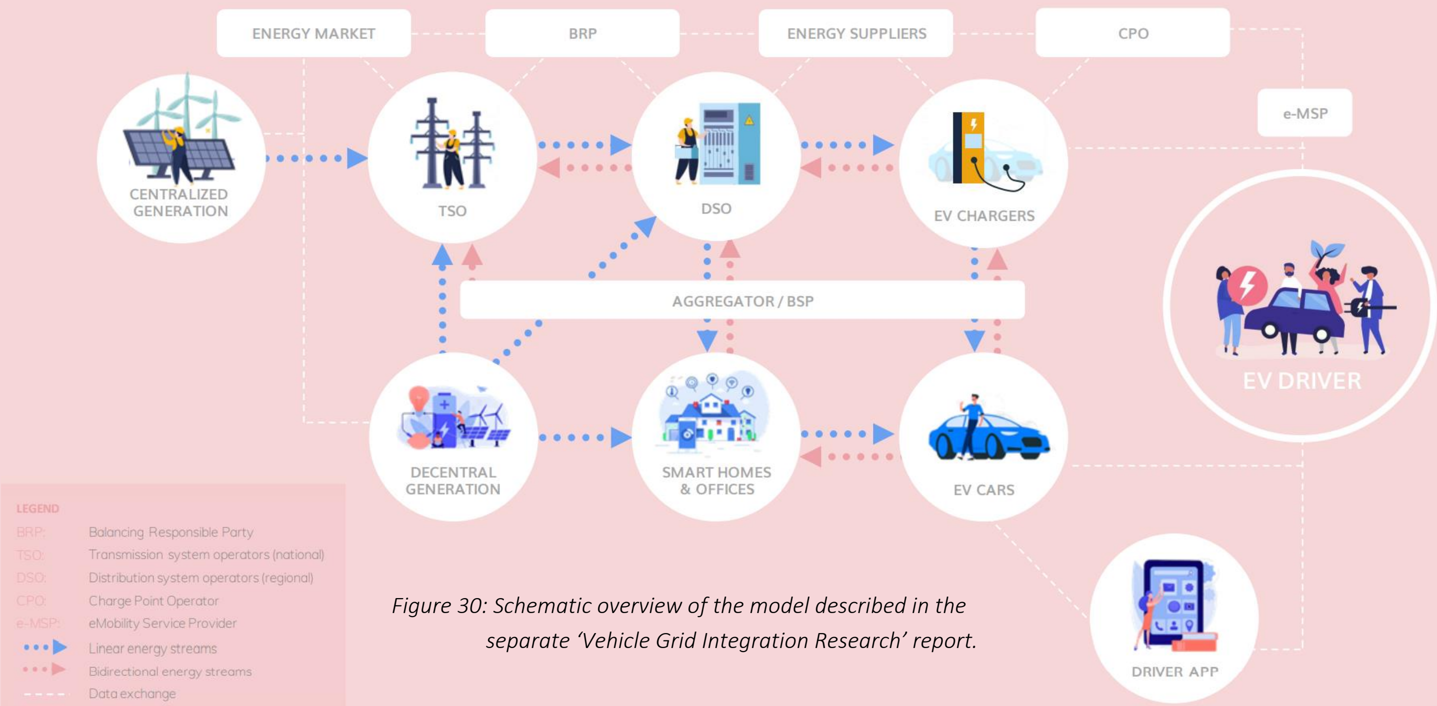


Figure 30: Schematic overview of the model described in the separate 'Vehicle Grid Integration Research' report.

LONG-TERM PERSPECTIVES FOR THE METHANE GAS SYSTEM

Production of green gas will exceed gas consumption in a few years

As the production of biogas increases and the consumption of methane gas is generally reduced through electrification, there will be a surplus of RE methane gas (BNG) in the longer term. The figure on the right shows a forecast for the production of green gas and gas consumption.

Biogas production is already expected to exceed Danish consumption by 2030. There will then be a surplus of RE gas. This can either be exported to the European market, particularly to Germany, or further processed into high-value liquid products such as methanol, jet fuel etc. in combination with PtX.

New electricity-based technologies for gas conversion

New technologies where electricity is used to convert different types of gas into synthetic gas, including electro-steam methane reforming (eSMR), are paving the way for new types of sector coupling between electricity, methane, hydrogen and CO_2. The electro-steam reforming technology has been included in the perspective analyses for many years, but has reached a pre-commercial development stage in recent years, and could have a significant impact on the future coupling of methane, hydrogen, CO_2 and high-value liquid fuels. An example of the technology is shown on the right. Methane, biogas and/or hydrogen in combination with CO_2 can be fed into eSMR. The input is converted into a synthetic gas consisting primarily of hydrogen and carbon monoxide. The synthetic gas can then be catalysed to form hydrocarbon fuels such as methanol, jet fuel (kerosene), diesel, petrol, plastic polymers etc. or catalysed into hydrogen and CO_2, which is stored. Since eSMR can convert different inputs into synthetic gas, it can serve as a flexible hydrogen consumer by using hydrogen (and CO_2) when this is cheap/available and otherwise using methane or biogas. eSMR can thereby serve as a virtual hydrogen storage facility.

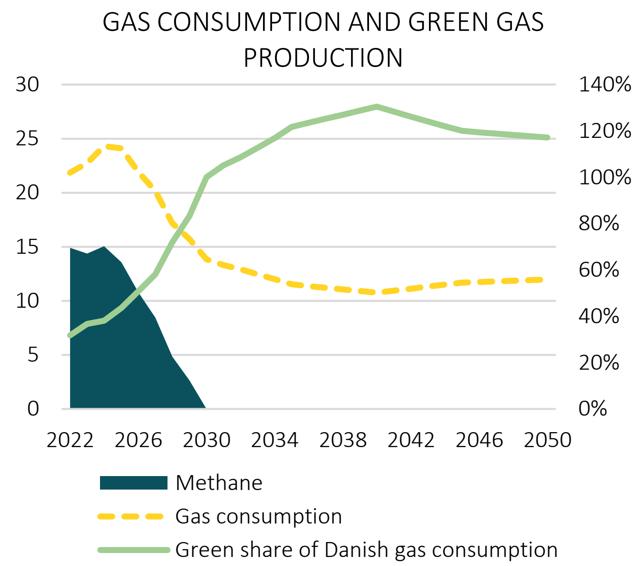


Figure 31: Analysis Assumptions 2022 (consultation version) project the scenario shown for the use of natural gas, gas consumption and the proportion of green gas.

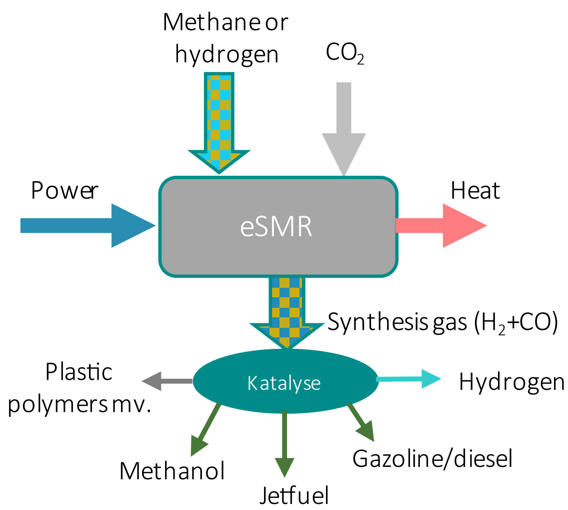


Figure 32: Process overview for an eSMR plant and subsequent catalysis process.

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Export green gas or convert it to liquid fuels?

With very high natural gas prices in Europe, exporting green gas may be more profitable than converting it into high-value liquid fuels (jet fuel, methanol etc.).

As a minimum, green gas exports to Europe can be expected to be sold at the market price for natural gas (including the cost of CO_2). Towards 2030, AA22 (consultation version) predicts that the natural gas price will be approx. EUR 14/GJ, including the cost of CO_2. This is on par with the price of upgraded biogas. Conversion of RE methane to RE methanol (at a market value of EUR 37/GJ), makes approx. EUR 24/GJ an acceptable price for RE methane gas. If a higher price cannot be achieved for green gas for export, some demand for using methane for liquid fuels can still be expected.

Below and on the following page are examples of using eSMR technology in the coupling between biogas, methane gas, hydrogen and CO_2.

Case 1 is the reference case where CO_2 is removed from biogas and it is fed into the grid. These types of solutions are currently undergoing strong development. eSMR is still not fully market mature, and given the current European supply challenges, there is an extraordinarily high need for methane gas in Europe, which makes this solution very relevant. As eSMR becomes fully market mature, presumably towards 2025, hybrid solutions (case 2) can in some areas lead to efficient interplay with biogas, and possibly serve as an internal network for hydrogen, with the possibility of feeding hydrogen and CO_2 into the upstream connection.

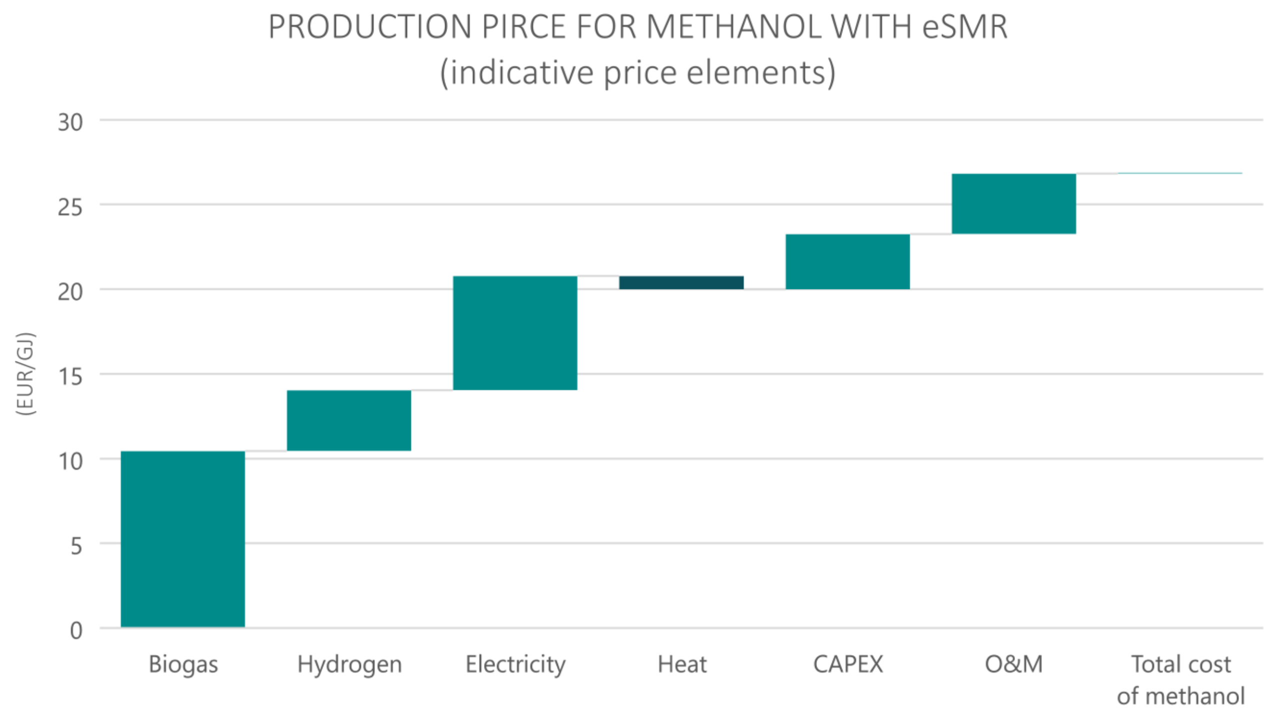

Figure 33: Production costs of making methanol from biogas, hydrogen and electricity using electro-steam reforming (eSMR) The technology is still being developed, and the figure is purely indicative.

CASE 1 – UPGRADE AT BIOGAS PLANTS AND USE GAS CENTRALLY FOR GAS-TO-LIQUID (GTL) (REFERENCE CASE)

The reference case represents the current deployment, where CO_2 is removed at biogas plants and methane is fed into the methane infrastructure.

Advantages:

- Large-scale eSMR and fuel production
- Good opportunities for utilising surplus heat
- Standardised (BNG) methane to supply consumption and possibility of exporting green methane
- Methane and hydrogen/CO_2 interplay flexibly to supply fuel production. This allows methane storage to be used as backup for fluctuating hydrogen production
- Hydrogen and CO_2 can be fed into supply (upstream) to the central eSMR.

Disadvantages:

- Extra costs to scrub or methanate CO_2 locally, only to add CO_2 again at the central unit, plus additional costs to compress into the grid.

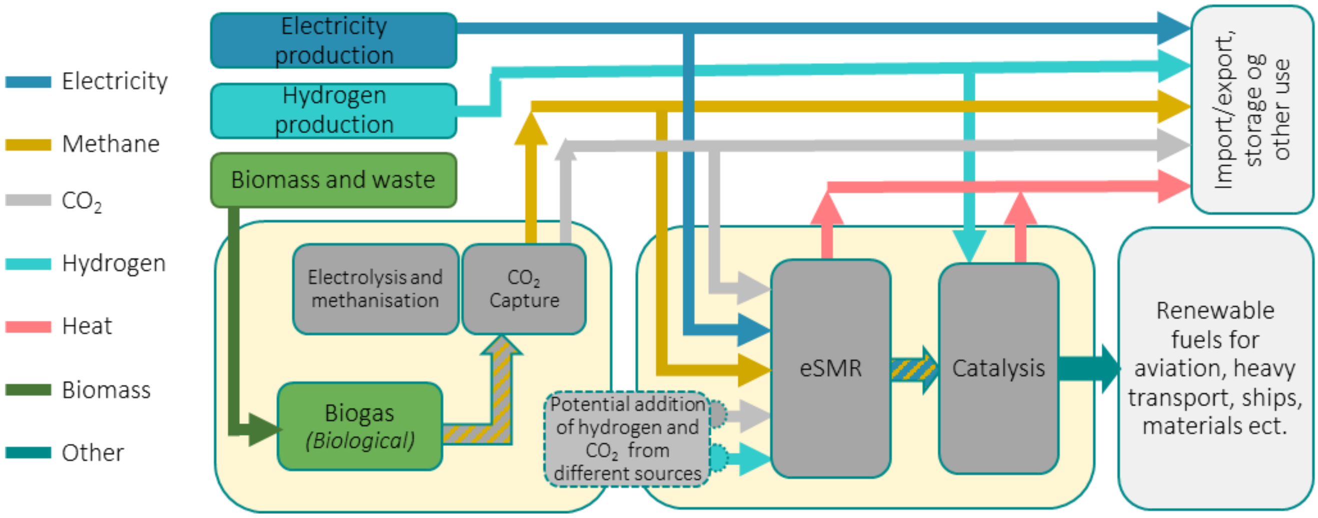

Figure 34: Model diagram for case 1, where biogas is upgraded and injected into central eSMR plants, primarily through the general infrastructure

New technologies for methanation can potentially reduce the costs of this and enhance this solution path. For example, bio-methanation as in 'Electro fuel from a bio-trickling filter'

CASE 2 – HYBRID MODEL

Biogas plants are connected to an industrial cluster for fuel production (eSMR/GtL). The model corresponds to the current deployment, where CO_2 is removed at biogas plants and methane is fed into the methane grid.

Advantages:

- Enables direct use of biogas without carbon capture
- Flexibility to utilise local resources (biogas, hydrogen, CO_2 and local storage for hydrogen and biomass)
- Good opportunities for utilising surplus heat
- Standardised (BNG) methane to supply consumption and possibility of exporting green methane
- Hydrogen and CO_2 can be fed into methane supply (upstream) to the central eSMR.

Disadvantages:

- Suitable for medium-scale GtL plants, but less suitable for large-scale production of jet fuel at refineries.

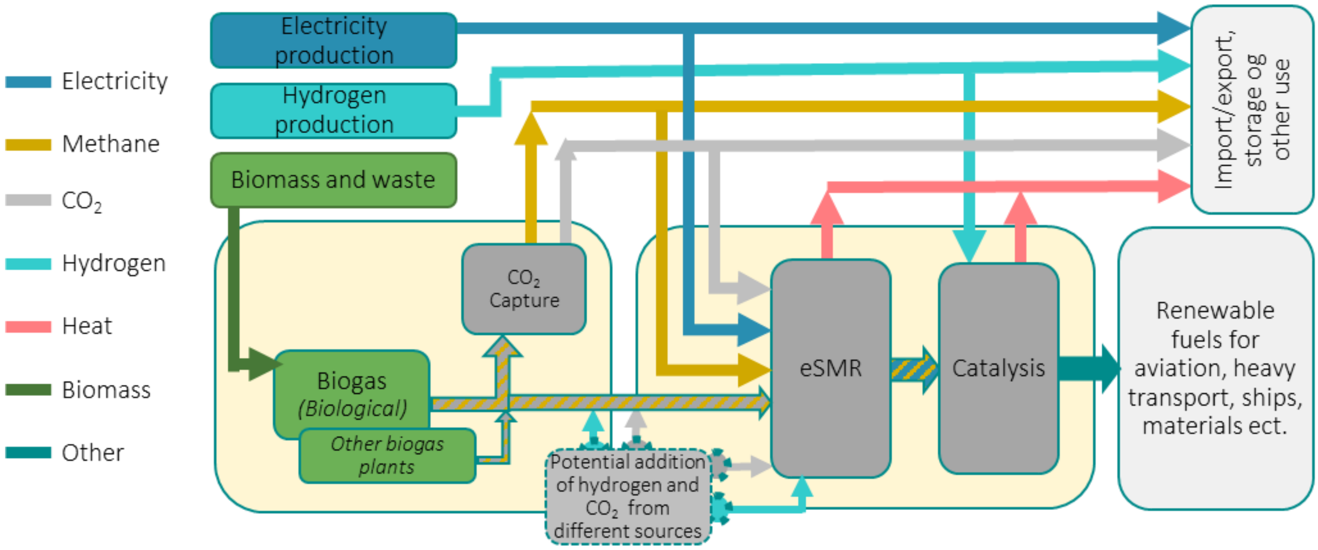

Figure 35: Concept diagram for case 2, where biogas from one or more plants is routed directly to eSMR plants.

CASE 3 – LOCAL GTL WITHOUT CONNECTION TO METHANE GRID

In this variant, biogas plants are connected to an industrial cluster with fuel production (eSMR/GtL), without any connection to methane and CO_2 infrastructure.

Advantages:

- Enables direct use of biogas without carbon capture
- Hydrogen could be fed into a local line between the biogas plant and eSMR, or electrolysis could be integrated with the eSMR plant.

Disadvantages:

- Small economies of scale
- Large-scale utilisation of surplus heat not possible
- Less flexibility in the energy system
- Potentially higher tariffs due to connection to electricity distribution grid.

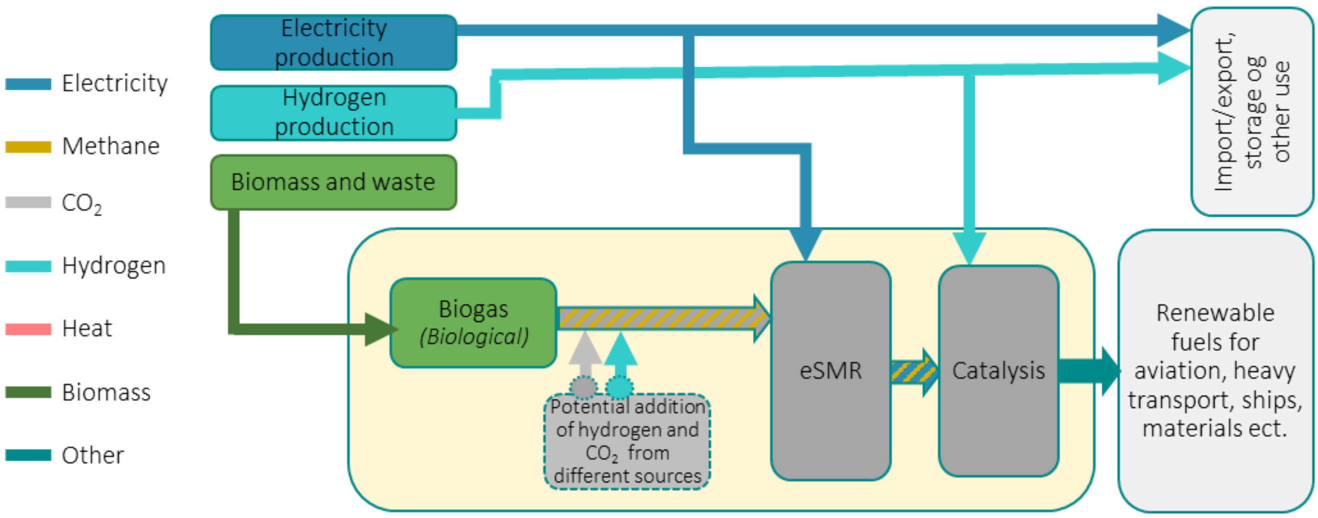

Figure 36: Concept diagram for case 3, where a biogas plant is located close to fuel production.

PTX AND INTERPLAY WITH BIOMASS

Biomass is a limited resource and is used efficiently through HTL, pyrolysis and gasification.

There is considerable interplay between the electricity, methane and hydrogen infrastructures and production of PtX fuels. So perspectives for PtX and CCU/CCS have therefore been included in this holistic perspective analysis.

Fuels are needed for energy services which are disproportionately expensive to electrify. Put simply, carbon-based fuels (such as diesel, jet fuel, petrol and methanol) are the easiest to handle, but also the most expensive to produce using renewable energy. So where direct electrification (heat pumps, and electric vehicles, ferries, planes etc.) is possible, this is the easiest path. If an energy service can operate using a carbon-free fuel such as ammonia or pure hydrogen, this may be a cheaper solution than hydrocarbon fuels in the long term. But for aviation and heavy transport, carbon-based fuels will often be required. The perspective analysis assumes a need for approx. 25 TWh of liquid fuels (methanol, jet fuel, diesel) in the medium term (up to 2040). Any production of fuels for export will be in addition to this.

Access to green carbon is a challenge in relation to the production of carbon-based fuels. With the stronger focus on only using biomass which is not in competition with food production, access to carbon via biomass is limited.

As a frame of reference, the analysis assumes that Denmark has access to 150 PJ/year of sustainable biomass/biowaste. If all the carbon from biomass and waste was combusted (theoretically, as this is not possible in practice) and the CO_2 was collected, this would provide just over 13 million tonnes of CO_2. Assuming that approx. 10 million tonnes of CO_2 has to be stored annually to achieve climate neutrality, and that producing 25 TWh of hydrocarbon fuels will require approx. 7 million tonnes of CO_2, it will be necessary to collect CO_2, for example from air (direct air capture).

Full combustion (eg at a CHP plant) of the biomass and CO_2 capture from the flue gas is a relatively expensive solution, and is not ideal in terms of recirculating nutrients from the biomass. There are several ways to produce hydrocarbon fuels, as illustrated in Figure 37.

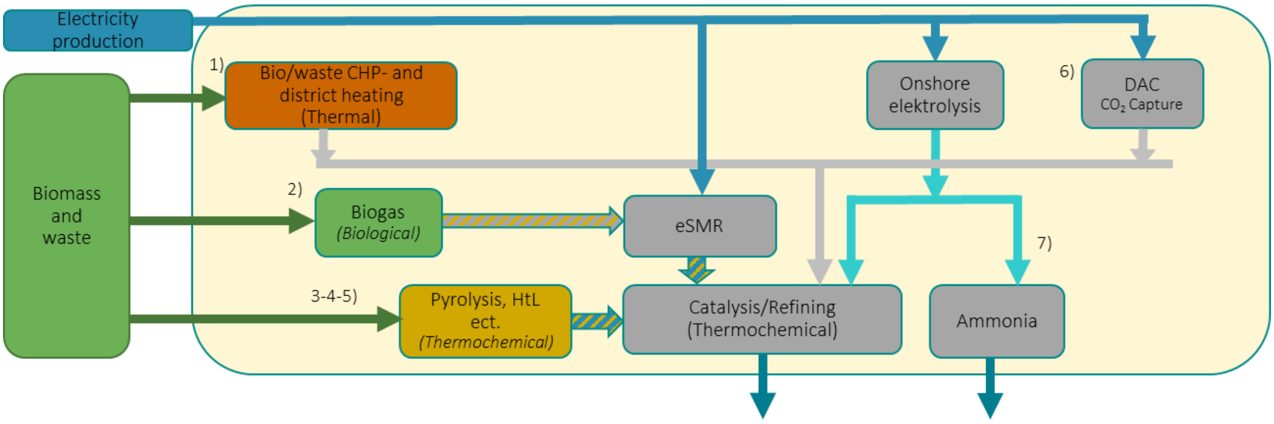

Figure 37: Illustration of seven different pathways for the production of fuels that contain carbon.

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The production pathways shown are:

1) CHP biomass combustion with CO_2 capture from flue gas which, together with hydrogen from electrolysis, is catalytically converted into methanol, jet fuel etc.
2) Biogas which is converted using electricity (eSMR) into synthetic gas, and then catalytically converted into methanol, jet fuel etc.
3) Pyrolysis
4) Full thermal gasification
5) Hydrothermal liquefaction (HTL)
6) Direct air capture and electrolysis-based hydrogen
7) PtX ammonia production.

Using technology data, the economic cost (CO_2 shadow price for fossil reference) has been calculated indicatively for these technology pathways. See the appendix for technology data.

The technologies have varying cost levels, but also varying degrees of maturity. Technology data indicates that direct use of bio/waste for PtX fuel production will be a more competitive pathway in the long term than conversion via power stations to CO_2 (which conversely is a mature technology).
With higher demand for sustainable biomass for both CHP plants and PtX, the competitiveness of the technology paths is important. When simulating scenarios in which the various bio/PtX technologies have to realise the climate-neutral scenario with limited biomass, direct conversion dominates (including both slow pyrolysis and pyrolysis with further full gasification of coke residue). Indirect bio-PtX with CHP production/carbon capture, used together with hydrogen for PtX fuel, is more expensive.

The thermochemical technologies (3, 4 and 5) push up the price of the scarce biomass, limiting investment in and operation of bio-CHP/PtX. Given that it is primarily the thermochemical technologies pushing up the price of sustainable biomass, it is also a possible breakthrough in these technology which will greatly affect the operation of bio-CHP/PtX.

From an electricity system perspective, it means that indirect bio-PtX (bio-CHP with carbon capture) may see fewer hours of operation if they have to compete with direct bio-PtX (thermochemical technologies.) The electricity system must therefore be based more on inverter-based wind and solar (PV) power, and possibly PtX to provide properties required to maintain power system stability.

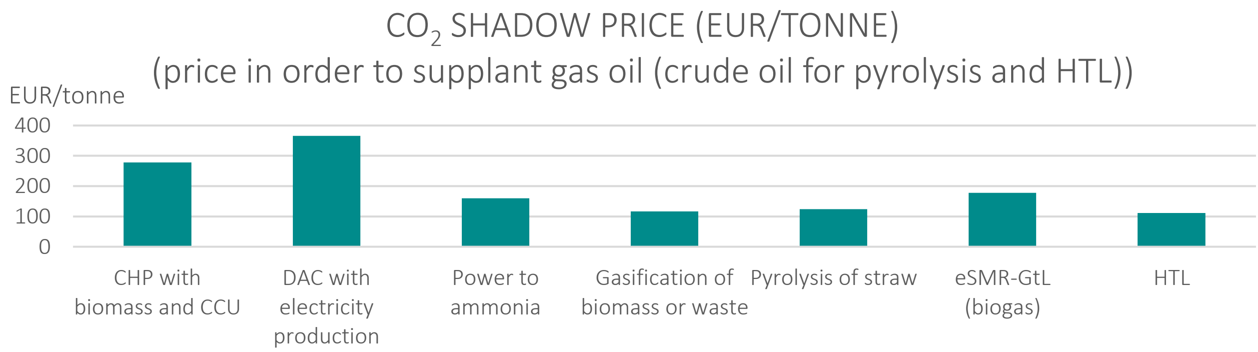


Figure 38:Shadow prices of CO_2 calculated as the cost of supplanting fossil jet fuel.

DIRECT AIR CAPTURE PERSPECTIVES ON INTERPLAY WITH PTX

Given the goal of climate neutrality, it is necessary to collect CO_2 from the environment and use it to produce fuel (CCU) and store it underground (CCS). Direct air capture has been included as an element in the system scenarios. The technology is rapidly developing, but is currently a relatively expensive way to collect CO_2. The technology is energy intensive and has high investment costs. Energy inputs are both thermal heat and electricity. Processes requiring thermal input at approx. 100°C are seeing rapid growth. Figure 39 shows the costs of capturing CO_2, assuming costs in line with the technology catalogue. See the appendix for a detailed data description.

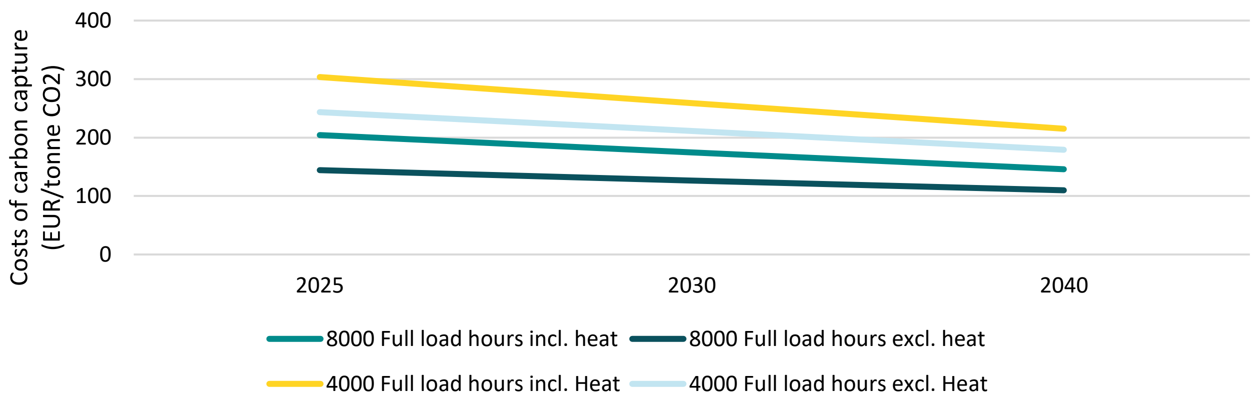


Figure 39: Costs of direct air capture based on the number of full-load hours. 'Incl. heat' means the heat is being paid for, while 'excl. heat' means free surplus heat is being used.

This type of technology also allows surplus heat from various PtX processes to be utilised. A number of PtX processes in the system scenarios produce heat exceeding 100°C (marked in dark red in Figure 40). For processes with lower output temperature, such as alkaline electrolysis, the temperature can be raised using a heat pump. By effectively combining heat from PtX and direct air capture, the costs of collecting CO_2 from air can drop below EUR 161 per tonne in the long term.

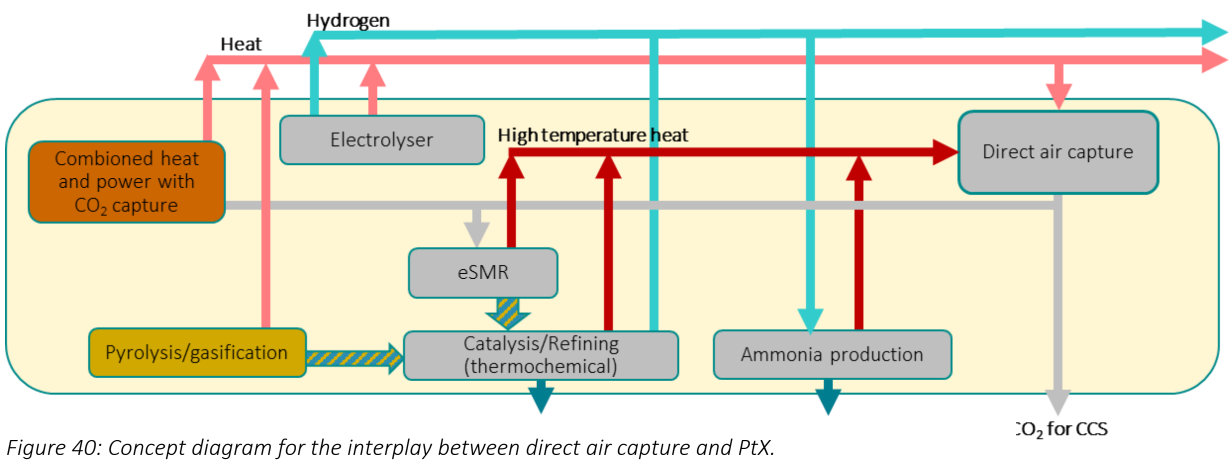


Figure 40: Concept diagram for the interplay between direct air capture and PtX.

CO_2 BALANCE IN THE SYSTEM ANALYSIS

In the scenarios with climate neutrality, it is assumed that the energy system must supply 10 million tonnes of CO_2 for storage (CCS) and also supply CO_2 for the production of carbon-based RE fuels (methanol, jet fuel etc.). In addition, it is assumed that CO_2 from cement production must also be stored (CCS). Figure 41 shows volumes and sources of CO_2 in the various scenarios.

A total of around 14 million tonnes of CO_2 will be collected from point sources at CHP and biogas plants and from direct air capture (DAC). Biochar has been converted to CO_2e. Figure 42 shows how the approx. 14 million tonnes of CO_2 will be used. 10 million tonnes of CO_2 will be stored (CCS), including from biochar from pyrolysis. The remainder is used for PtX and for injecting CO_2 into gas-to-liquid processes. While some biomass supplies CO_2 via CHP and biogas production, other biomass is converted directly into carbon-rich gas (synthetic gas) and RE oil products using gasification and pyrolysis. This results in production of 25 TWh of RE fuel and 10 million tonnes of negative CO_2 emissions for the energy system, as the basis for climate neutrality while there continue to be emissions from non-energy-related activities. The scenarios for climate neutrality have been simulated for 2035 to assess whether the energy system, with the simulated technical and market measures, is able to handle such an accelerated process.

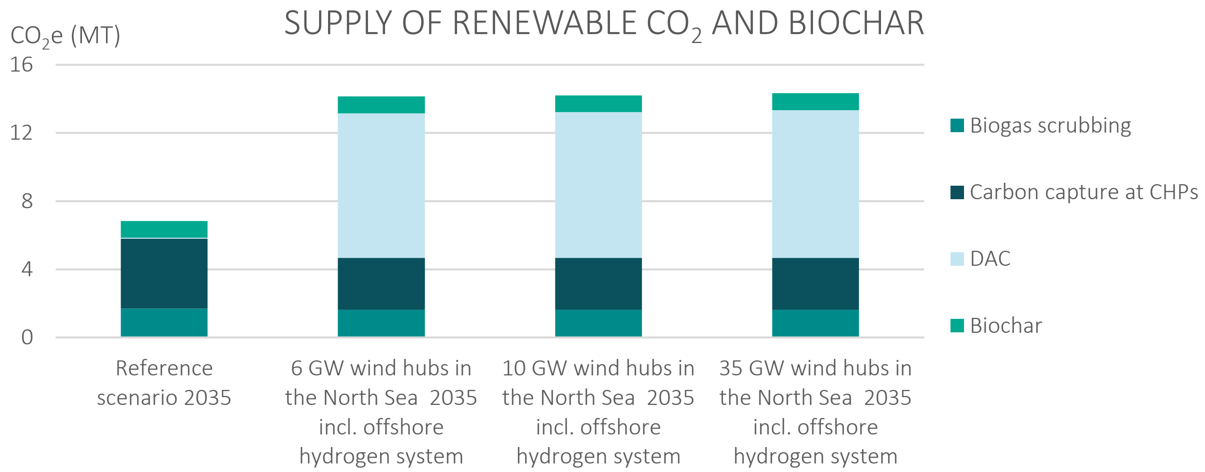


Figure 41: Volumes and sources of CO_2 and biochar in the system scenarios with a hydrogen system.

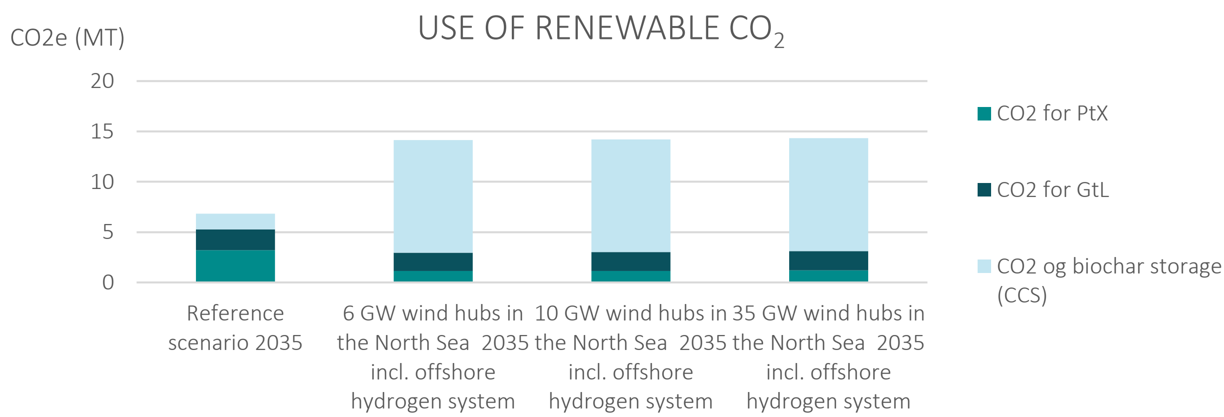


Figure 42: Figures for how renewable CO_2 is used in the scenarios with an offshore hydrogen system.

PERSPECTIVES FOR SYSTEM DEVELOPMENT

Condensed overview of parts of Energinet's development initiatives towards being able to operate and develop a Danish energy system based on 100% renewable energy.

FROM SCENARIOS TO DEVELOPMENT NEEDS, DESCRIBED WITH R&I PERSPECTIVES

The purpose of the perspective analyses and scenario work is to provide input into planning electricity, gas and hydrogen infrastructure, and to focus on the system development required to handle the substantial transformation the energy system is facing.

The most ambitious scenario sees a more than tenfold increase in renewable electricity generation from wind and solar power compared to today's level. Input from the scenario analyses is used to assess general and specific issues and development needs in the longer term. Energinet describes this development need in perspectives for research, development, innovation and demonstration (R&I perspectives).

The perspectives for R&I seek to identify and advance the interdisciplinary common ground and direction and long-term synergies. They aim to serve as inspiration and suggestions for areas where Energinet has a particular interest in joint development in the field. The challenges and solution paths are therefore only briefly outlined in the following pages.

The perspectives are a tool that is constantly evolving. They can be used to place development projects in a broader context, identify synergies and provide insight into long-term development trends in other fields. The figure below shows the path from the scenarios to the description of development needs.

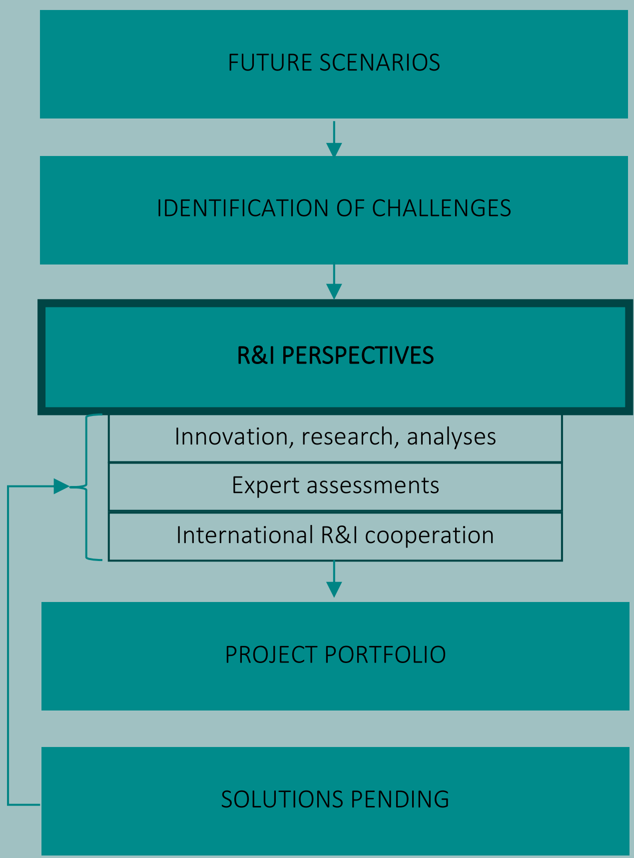
FUTURE SCENARIOS have been assessed based on the analysis assumptions, system perspective analyses, other scenario analyses and input from various fields. The direction is assessed across a range of possible long term outcomes.

IDENTIFICATION OF CHALLENGES describes areas where assessment shows that a 'business as usual' approach will cause problems that make the transition unnecessarily expensive and/or could compromise security of supply.

R&I PERSPECTIVES describe possible solution paths to handle the identified challenges and R&I needs. The solution paths are described using knowledge from the various fields, expert assessments, R&I collaborations etc. The perspectives are presented briefly on the following pages.

PROJECT PORTFOLIO consists of the projects that have been launched to acquire the necessary knowledge and mature the identified solution paths.

SOLUTIONS PENDING are the issues where no work is currently being done on a solution path related to Energinet.



FOUNDATION FOR THE GREEN TRANSITION

Challenges and long-term development needs have been assessed based on general planning data, perspective analyses and expert knowledge.
The context for the work on R&I perspectives is Energinet's current position, our current projects and expectations for the future. With input from a range of experts, area strategies and management groups, the overall current position has been mapped out in the form of identified key challenges, current projects and expected future projects.

Given Denmark's political goal of reducing CO_2 emissions by 70% by 2030, the longer term goal of climate neutrality, and the fact that Denmark has large offshore wind resources that will play a key role in the European transition (see the perspective analyses), there is a major need for development in the coming decades.

The recent Thor tender showed the competitiveness of wind resources. The realisation of sector coupling has also really gained momentum.
Energinet's scenario analyses show that both offshore wind (approx. 2 GW at present) and solar cells (approx. 2 GW at present) will see a more than tenfold expansion in the longer term. Potentially flexible consumption will see similar expansion through sector coupling involving electric vehicles, heat pumps and Power-to-X (PtX), from around 1 GW today to over 25 GW longer term.

A good foundation for the green transition

The perspective analyses show major changes ahead, but new technologies and knowledge will make it possible to handle the many challenges. With significant development in power electronics and digital capacity, and progressive development in new sector coupling technologies (such as PtX), analyses indicate that the challenges can be solved.

As TSO, Energinet is responsible for some of these solutions, and for much of the foundation on which the Danish energy system is being developed. R&I has to pave the way for best-in-class technologies and solutions to be utilised, that address the energy trilemma – whereby security of supply, affordability and the green transition have to all be balanced. Best-in-class solutions comprise here technologies and concepts that are known in the market, inspiration from TSOs in other countries, and promising new elements which can be implemented in the foreseeable future with an R&I effort.

Key elements in a good foundation

A good foundation for handling the major transition requires several elements to be present. This can be categorised in many ways. Some of the core categories in an efficient electricity and gas foundation include:

1. Economic incentives to invest in and operate plants efficiently in the integrated system
2. Reliable and secure system operation
3. Utilisation of new emerging efficient and relevant technologies
4. Analytical methods for planning, designing and operation of the integrated system
5. A data backbone which provides the information necessary for the market and system operation.

The five categories are explained on the next page. Note that none of the categories can be viewed in isolation or stand alone.

The various elements greatly influence each other, and the aim of the perspectives is to create a forum for identifying and cultivating cross-cutting synergies.

R&I PERSPECTIVES – INITIATIVE CATEGORIES (WITH REF. TO FIGURE 43)

1) Price signals ensure optimum investment and operation of the integrated system
Optimum investment in and use of players' and Energinet's plants will demand efficient price signals in the market and internally in Energinet. The market for electricity and gas, combined with other financial incentives such as tariffs, connection conditions and revenue caps, are key price signals for investing in and operating plants.

2) System operation utilises plant resources securely and optimally through automation
System operation must ensure that electricity and gas infrastructure in the market and belonging to Energinet are operated so as to ensure optimum flow in the electricity grid, a constant voltage level, system stability and power balance. As more plants, both central and local, are able to supply flexibility and ancillary services, the complexity of electricity and gas system operation will increase. Use of new data technologies such as artificial intelligence (AI), combined with more information about system state, will allow better optimisation of operations and utilisation of physical capacity closer to its limits. This will also increase the complexity of system operation. This greater complexity will make it necessary to gradually supplement and ultimately replace manual actions with operations support and much more automated system operation solutions. Automation is not a goal in itself, but a way of optimally utilising the system's many resources (central and local) and is thus key to addressing the energy trilemma. The goal is therefore to exploit the potential for operational support and automation to ensure that the system's resources are utilised optimally, while maintaining a high level of security of supply.

3) Models that realise the potential of new technologies
Technologies for the energy system are constantly developing. It has to be possible to phase these technologies into the energy system and realise the value and synergies they offer. Examples of technology trends which open up potential new solution paths:

- Computing for real-time analyses
- IoT for small dispatchable plants based on price signals
- HVDC coupling – multi-terminals, hubs etc.
- PtX technologies and hydrogen infrastructure, that convert electricity into green fuels.

4) Digital energy system twin – in planning, designing and real time operation of the integrated sysetm
Advanced modelling, where real-time data from the actual system and new data technologies such as AI and machine learning are used, are widely referred to as 'digital twins'. Modelling of the electricity and gas/hydrogen systems in interplay with the entire energy system is essential for all phases – from long-term planning and development of new system solutions to real-time market and system operation. It is necessary to be able to model the system in planning and in real time operation to a greater extent than today. 'Digital twins' refers to the fact that the system can be modelled dynamically, so that models and data can be used in combination – from planning and design to the establishment and operation of plants. It is not just one simulation model, but several models for planning and real-time operation which interplay well, based on a functional data foundation.

5) Data back-bone that supports price signals, system operation and advanced analyses using digital twins
A functional, robust and secure data foundation is essential in order to realise price signals, system operation and system calculations using digital twins. Data is the information 'glue' which is essential to many of the other solutions. It is therefore important to have an open, accessible and well-structured data architecture and data governance that supports price signals, system operation and advanced analyses using digital twins.

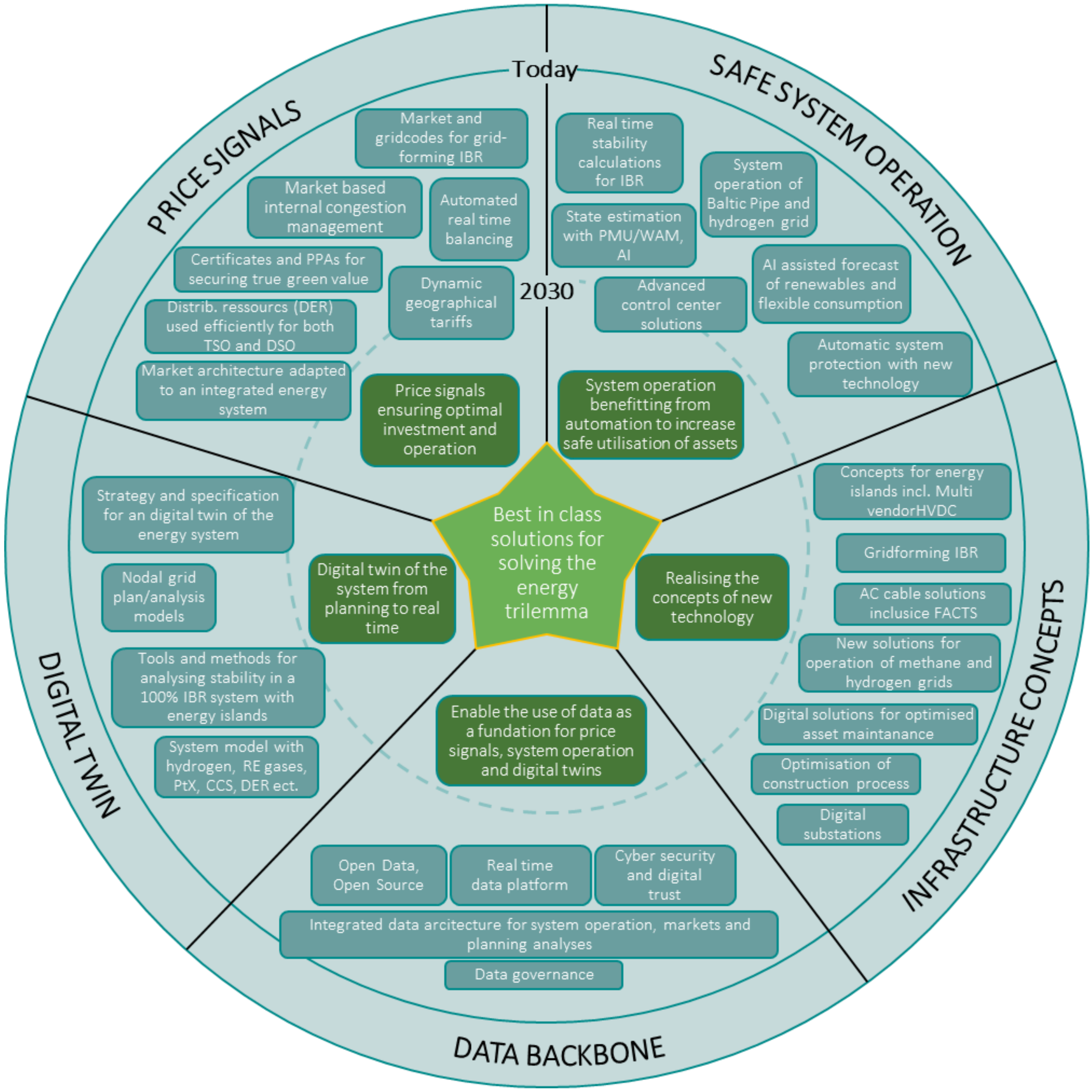


Figure 43: R&I Perspectives in five categories with a number of key R&D areas to pave the way for the climate negative integrated energy system based on 100% renewable energy. The key areas are further described at page 50-55.

SUBJECTS AND INDICATIVE SOLUTION PATHS

CATEGORY: PRICE SIGNALS ENSURE OPTIMUM INVESTMENT IN AND OPERATION OF PLANT

Direction: Market-supported system operation, such that financial incentives – through the market, tariffs, taxes and framework conditions – ensure that investments are made in player and infrastructure resources in the energy system (one-system-of-systems) and that these are optimally utilised.

Subject	Example solution paths
Market and grid codes from PEIDs (Power Electronics Interfaced Devices) As converter-based resources (PEIDs) increasingly form the core of the electricity system (gridforming), it may become relevant for advanced ancillary services to be increasingly provided by these power-electronics-connected resources.	Incentives may be created, as appropriate, for PEIDs to provide more ancillary services. Real-time data processing can be used to continuously assess the need for gridforming ancillary services, such as inertia, during the delivery hour.
Internal congestion can be handled by the market Internal congestion is a rising problem in both the electricity and gas systems, in step with the massive expansion of RE, PtX and distributed resources (DERs).	More dialogue via capacity maps, establishing the option of geographical tags in market solutions (eg manual fixed frequency reserves, mFFR) and adjustments to bid zones for both electricity and gas in the longer term.
Ensuring power balance in the delivery hour (balancing philosophy) The rising proportion of wind/PV power increases the risk of imbalances in the delivery hour. There is a need to strengthen the balancing options by adding new resources, such as demand-side response.	Greater internationalisation of balancing bids (common frameworks and standards). Near-real-time market by reducing market time increments. Publish imbalance price close to real time (see also balancing initiatives for system operation).
Tariffs that take geography into account There is currently a flat tariff for electricity and gas consumption, irrespective of the transmission distance.	In the short term, the option of direct lines between production and consumption. In the long term, possible adjustments to system tariffs.
Distributed resources in the market (TSO/DSO) The increasing use of distributed resources such as electric vehicles, heat pumps, solar cells and batteries increases the congestion problem in the DSO grid, affecting DERs in the electricity market. There is a risk that DSO and TSO solutions will not work well together.	There can be collaboration with DSOs on the development of solutions, whereby flexibility and congestion in the TSO/DSO grid can influence the market.
Market architecture for integrated energy system (electricity, gas/hydrogen, heating) Price signals for electricity, gas (including hydrogen) and heating do not necessarily interplay optimally. With greater system integration, it is important that market solutions work together.	Architecture that supports sector coupling will be analysed. The need for optimisation and adaptation will be assessed based on this.
RE value via certificates and PPA There is currently no certificate solution that offers full additionality in relation to RE supply.	Establish temporal declarations, which may help increase the value of RE (increase simultaneity). Analyse the problem of lack of additionality.

CATEGORY: SECURE AND OPTIMAL OPERATION OF THE INTEGRATED POWER/GAS/HYDROGEN SYSTEM

Direction: System operation that utilises plant resources securely and optimally through improved automation

Subject	Example solution paths
State estimation (electricity, gas and hydrogen) To assess whether the system is stable – and to assess optimum operating conditions with maximum resource utilisation, it is essential to have a detailed assessment of the system state.	Using more advanced measurements, including solutions using PMU/WAMS for the electricity system, and using models (digital twin) for the electricity and gas/hydrogen combination, knowledge of the system state can be increased.
Stability calculation – with an increasing proportion of converter-based plant (PEIDs) The increasing proportion of converter-based resources (PEIDs) is fundamentally changing the dynamics of the electricity system compared to the past system using rotating synchronous generators. Calculating dynamic system stability, both offline and in real time, requires different simulation tools, component models and approaches than are used for classic electricity systems. The complex models need more CPU time and are difficult to use in real time.	Operation support tools can be established that are capable of simulating the dynamics of the electricity system – offline, in near-real time and in real time, including for PEID-dominated systems. For example, using EMT models for dynamic analyses, drawing on AI, stochastic models etc. to achieve speeds that allow the knowledge to be used for system operation. See also the description of 'digital twin'.
RE and flexible consumption forecasts Greater volumes of wind, solar power and flexible consumption are making forecasting more crucial to the optimum utilisation of system resources. Errors in forecasts can also have fatal consequences for security of supply.	System operation using probabilistic calculations of balance and capacity requirements. Digital solutions using AI can be used to increase the precision of forecasts for wind, PV and flexible consumption from small and large units (DERs).
Advanced operation support tools The complexity of the energy system will increase dramatically over the coming decades. With flexible resources such as HVDC, PtX and DERs, the solution space for optimum operation (SCOPF) is larger and more complex. It is more difficult to establish an efficient and secure operations solution.	Real-time analyses that can identify the optimum use of regulating power bids, system coupling in the integrated system and set points for plants can be used to make recommendations to the operator on duty and more automation of the operation.
System complexity increases the need to automate operations The complexity of the system is increasing, while there is also a need for quick responses to incidents in the system in order to maintain secure operation.	Automating system operation can reduce response times and make it easier to operate complex systems more optimally.
Automatic system protection with new technology With greater complexity and changed dynamic properties from PEIDs, the electricity system is essentially becoming more unstable.	More automatic built-in robustness can be established in the electricity system so that it seeks a stable system operating state without any operator intervention.
System operation with Baltic Pipe and hydrogen Baltic Pipe and a possible hydrogen grid are fundamentally changing the dynamics in the gas system.	Competencies are being strengthened in gas system operation, so that Baltic Pipe and new gases such as hydrogen can be handled in system operation.

CATEGORY: INFRASTRUCTURE TECHNOLOGIES AND CONCEPTS

Direction: Knowledge of future 'best in class' infrastructure solutions, composition options and models that allow a technically and economically efficient energy system.

Subject	Example solution paths
Offshore concepts in interplay with sector coupling onshore Concepts in which offshore hubs are established can serve as collection points for large volumes of wind power, where the hub (or energy island) can connect to several countries, or connect other offshore hubs. The solution can be combined with offshore electrolysis to produce hydrogen, which is brought ashore and fed into the hydrogen infrastructure. There is a need for more knowledge about cost-effective models and stable operation of meshed HVDC (multi-terminal). Multi-HVDC is expected to be expanded in the coming decades. To ensure competition in tenders there may be a need to standardise HVDC terminals (multi-vendor).	System and cost-benefit analyses on a number of different concepts to identify solution paths. These include models with central/local solutions, with/without offshore electrolysis, etc. More detailed assessment of technical solutions, dynamic stability and technical feasibility for the various models to ensure interoperability. Seek international cooperation in order to establish knowledge and progress on multi-terminal solutions and standardisation towards multi-vendor solutions.
Grid forming response from PEIDs (Power Electronics Interfaced Devices) Research and innovation is needed in order to make optimum use of PEIDs in the future energy system. PEID plants (wind turbines, PV plant, HVDC plant, PtX, batteries etc.). are still lacking in delivering gridforming response and by this support the stability of the electricity system in the same way as traditional power stations. Technically, PEIDs can potentially deliver grid-forming capability, but specifications, ancillary service market etc. are lacking for the required properties.	Getting inverter-based solutions to support the power system like traditional power stations is an issue that is being worked on nationally and globally, in industry and research, and in relation to control SW, simulation and measurement. Energinet is involved in several forums and international projects, to ensure the necessary knowledge is acquired to utilise the solutions in the market. See reference 7 and 8 (ENTSO-E and G-PST)
Handling harmonic distortion in AC cables Harmonic distortion from power electronics interfaced devices (HVDC, RE plant etc.) in combination with high impedance in AC cables creates a risk of resonance phenomena and associated voltage disturbances in the grid. These are phenomena which can lead to system disturbances in control systems and thus have a fatal impact on security of supply. To counter this issue, only a very limited proportion of AC cables can be established in the overall electricity system.	Energinet strengthens internal competencies and international cooperation in simulating dynamic stability and harmonic distortions in the power grid. Projects are conducted, for example, at the Technical University of Denmark, to assess whether inverters – which are part of the problem – could also become part of the solution by serving as active filters to reduce harmonic noise.
Development of SF6-free components SF6 gas is a potent greenhouse gas which is currently used extensively in high-voltage assets. Good alternatives need to be developed.	It is currently difficult to purchase SF6-free plant, as good alternatives have not been developed for all plant types. Work is being done to find solutions at an international level.

CATEGORY: INFRASTRUCTURE TECHNOLOGIES AND CONCEPTS (CONTINUED)

Subject	Example solution paths
Gas/hydrogen plant and operations solutions Under the new PtX strategy, Energinet and the DSO-company Evida will have the opportunity to own and operate hydrogen infrastructure, which means that Energinet will take on a new role in the energy system. System analyses already show that in cluster areas, or dedicated lines, hydrogen may be cost-effective in the longer term, adding a new dimension to holistic planning for the full energy system. Many new fields and knowledge areas related to the construction, planning and operation of hydrogen infrastructure therefore need to be investigated.	Strengthen knowledge in relation to system planning and operation using hydrogen. Holistic planning for electricity, gas and hydrogen can thereby be improved. This includes knowledge about conversion of existing methane compounds or establishing new dedicated hydrogen compounds.
Digital solutions for asset maintenance Fixed intervals for asset maintenance leads to situations where some assets undergo more frequent maintenance than necessary given operating hours and wear. Reinvestment based on fixed periods can result in failure to fully utilise the technical life of the asset.	Advanced measurements of asset condition, coupled with knowledge about usage and stochastic assessments of faults may make it possible to perform more optimal 'condition-based maintenance' and more fully utilise the technical service life.
Optimise construction processes using data The construction processes for Energinet's many projects make up a complex system. Coordinating construction projects while taking system operation into account and ensuring against outages in relation to construction work constitutes a complex problem.	Greater use of digitalisation paves the way for ensuring knowledge sharing and an overview of many projects, in order to analyse and organise projects more optimally. Digital solutions can be developed to support these optimisation processes.
Strategy for substations, including digital substations There is a rising need for information (measurements, system state etc.) about systems at switching substations, transformers etc., to use as a basis for optimising system operation. Old substations are less equipped with digital data readings than newer substations. A digital substation with a detailed and well-established digital interface for measuring and controlling the substation components paves the way for more optimal operation.	Energinet predominantly has classic substations, that cannot be regarded as digital substations. Analyse to what extent the necessary information access to these stations exists or can be established and use in enhanced operation of the power system.

CATEGORY: DIGITAL TWIN – FROM PLANNING TO REAL TIME

Direction: Digital simulation environments have been established for the integrated energy system which can support analyses, from planning to real time.

Subject	Example solution paths
Digital twin strategy and specification for the energy system Closer integration of the energy systems (electricity, gas/hydrogen, heating, PtX fuels, CO_2 etc.) will lead to a completely different dynamic in the system than exists today. But to be able to master this dynamic, it has to be possible to evaluate it in a simulation environment. To this end, Energinet already has various models that simulate the physical energy system and thus act as a digital twin for the real operation. However, development potential remains, whereby the existing models and digital twins can more closely resemble the real operation, closer to real time. For example, a digital twin which can capture the dynamics of the energy system in real time could be used more broadly to describe the coupling between the market and physics, provide training environments for operation and support faster development into a fully renewable based integrated energy system.	Prepare a strategy and a specification for the further development and use of digital twins in planning, the market and system operation, also serving as input to the necessary data foundation, model complex and governance. The model complex may be integrated to varying degrees, but the vision is a data foundation which ensures more direct data coupling across models. The emphasis is on international cooperation and standards, to ensure optimal exchange of data and models. Common Grid Model (CGM) is an example of data for digital twin that could be further developed towards an integrated energy system modelling.
Stability analysis in a 100% PEID system and energy hubs As inverter-based plants increasingly dominate the electricity system, better expertise is needed for performing dynamic analysis of the stability of a system that is up to 100% inverter-based. With the vision of establishing offshore energy hubs, there is extra focus procuring the necessary knowledge about inverter-based systems. The need to be able to analyse the components of different suppliers in interplay, so they can be integrated into the power system without jeopardising security of supply, increases the complexity of dynamic stability considerably.	Energinet focuses on building up competences, simulation tools and models for performing dynamic analyses of an inverter-dominated electricity system. The issue has a broad international focus, and international cooperation towards a solution is therefore being established.
Grid analyses that look at coupling the market and physics As more and more plants with a high level of flexibility are established centrally (eg PtX plants) and locally (eg over 1 million electric vehicles, heat pumps and PV power plants), the need for system solutions whereby the market and physics are well integrated increases. Planning of the electricity system is currently focussed around large zones without congestion (DK gas zone and DK1/DK2 electricity zones). Models and methodical approaches are needed whereby both the electricity and gas/hydrogen grids can be planned, such that flexibility is utilised in real time operations to handle internal congestion in both the electricity and gas grids.	Investigate whether existing tools used at Energinet such as PowerFactory, PowerWorld, PSCAD and Simone combined with energy model tools (eg Sifre and BID), can handle the task or whether supplementary tools are needed. Based on this evaluation, establish modelling tools, data models and governance for system analyses and planning, whereby new flexible resources with a closer market/physics coupling are brought into play.
Hydrogen/RE gas/PtX/CCS/DER system model Further development is required on a model complex where the various energy carriers of the energy system are analysed in interplay. Simulation of hydrogen also requires new solution paths in relation to modelling.	Investigate how analysis models for electricity and gas, the Perspective Model (Energy system model) and existing and new model environments for gas (Simone) and PowerFactory can be developed.

CATEGORY: DATA BACKBONE

Direction: The data backbone must support markets, system operation and system analyses, so the integrated energy system's full potential for cost-effective and secure operation can be realised.

Subject	Example solution paths
Unified data architecture Efficient data interplay is needed across energy systems, and across planning and operation processes. To realise this, a data architecture is needed so that local systems have cross-cutting interfaces.	A data space for the energy sector can be prepared in cooperation with the sector. An architectural plan for energy system data can be established across energy systems and across processes. The data platform can support efficient interplay between analysis models as part of a digital twin.
Open data and open source strategy There is a much stronger focus on open data and open source tools. This is especially true in international cooperation. This is currently a focus area for Energinet, but for integrated energy systems in particular, open source strategy solutions are still a long way off.	The platform can better support an open and module-based architecture. The solution can be open for new open source modules to be connected to the data platform.
Data governance In step with a stronger focus on a unified data architecture and efficient data processing, there is a greater need for stronger data governance.	One solution path is to work on establishing data governance that supports new cross-cutting usage of data internally in Energinet, and on data governance which can ensure processes where data is used in interplay with external players.
IT security and digital trust Greater use of data across the energy sectors, data openness and use of machines as legal entities (eg machine-to-machine trading), is increasing vulnerability in relation to data systems and the need for IT security and solutions involving digital trust.	Focus can be given to security and robustness in relation to IT. Solutions for digital trust can be developed and implemented so that machine-to-machine trading, agreements, etc. are supported as a secure solution (secure machine ID). Overall, the acceleration of new digital and data-based business models can be supported.
Data platform further development Based on the plan for a unified data architecture, including the real-time platform, there is a need for further development and adaptation of the data platform.	The data platform, incl. energy data service, can be part of the foundation of the data backbone. Based on the architecture plan, the data platform can be further developed with a focus on high security.

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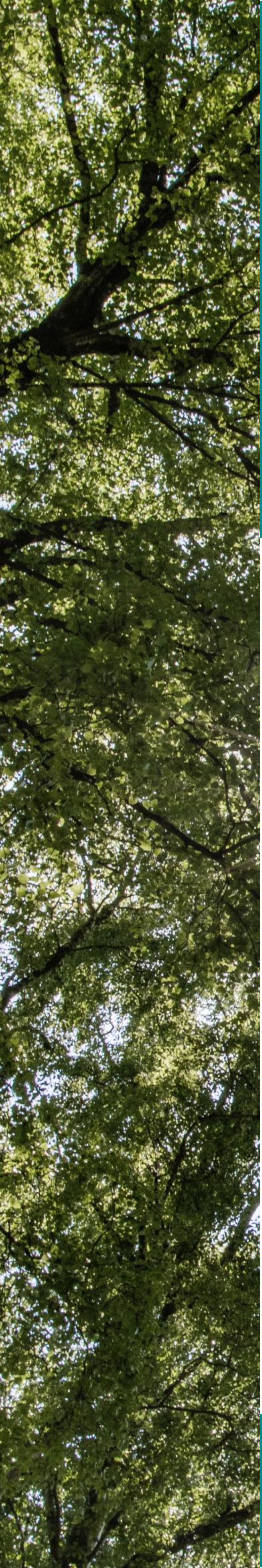

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