SUPPORTING A COST-EFFECTIVE GRID STRATEGY FOR ELECTRIFICATION

Co-location and cost-reflective tariffs

Ørsted, April 2022

Preface

Dear reader,

The electrification of industries and households holds a high position on EU policy agendas. Electrifying processes and equipment reduces emissions and combats climate change while electrical power at the same time becomes a cheaper input than traditional power sources.

The Danish energy landscape is traditionally characterised by small power producers and consumers, and there is essentially no large industry. The electrification will change this picture of small producers and consumers to larger ones.

Hydrogen, derived from a Power-to-X process, is one way to use electrical power with many applications in various industries.

The cost of electricity as an input to the Power-to-X process is an important determinant to the choice of location for hydrogen producers. Transmission grid tariffs constitute a large share of the cost of electricity and can hence have a large influence on the choice of the cheapest production area.

To avoid transmission grid tariffs, power producers and hydrogen producers can form a closed system without any connection to the open electricity grid.

However, from both a socioeconomic and a private commercial point of view, there are large benefits in "opening" the closed system to a semi-closed system by also establishing a connection to the open grid. The hydrogen producer can draw electricity from the open grid when needed. The open grid can use the connection to the semi-closed system as balancing tool and as interconnector to other price areas.

Further, when the semi-closed system draws electricity from the open grid in hours with ample spare capacity, the de facto additional costs to the transmission grid operator are limited, and the capacity in the grid is better utilised.

A semi-closed system connected via an interconnector has large socioeconomic benefits. It eliminates the need for parallel infrastructure, e.g., direct lines.

It is thus fundamental to choose types and levels of transmission grid tariffs that send the right signals to hydrogen producers. At the same time, transmission grid tariffs in most jurisdictions must be cost-reflective as transmission grid operators are natural monopolies and not allowed to make profits.

Against this backdrop, Ørsted has asked Copenhagen Economics to use an illustrative example inspired by Green Fuels to Denmark to

- Analyse how co-location of power production and consumption 'behind the meter' and with a limited connection to the public grid will impact the required grid capacity.
- Analyse how a cost-reflective TSO tariff regime consists of capacity-based elements
- Discuss what can be expected in terms of overall TSO tariff revenue given such new tariffs
- Discuss the distributional effects of new tariffs

We are pleased to present the analyses in this report.

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A changing energy landscape: new opportunities and challenges

The EU energy systems are undergoing fundamental changes these years with two fundamental drivers. First, the need to address climate change is rising as a political priority across the EU and the Member States as well as on a global scale requiring a massive reduction in emissions from fossil fuels. Second, significant cost reductions in wind and solar power have increased green electrification's attractiveness as a route towards decarbonisation. Both directly as a power source for electrical vehicles, heating, and industrial uses as well as indirectly by production of green hydrogen with many potential applications.

In Denmark, increasing wind power production is one of the corner stones in reaching the 70 per cent reduction ambition towards 2030. Another corner stone is the establishment of hydrogen or so-called Power-to-X production in Denmark to facilitate indirect electrification.[1] In March 2022, the Danish government realised the Power-to-X agreement for Denmark, which aims at developing 4-6 GW of electrolysis capacity before 2030.[2]

While the electrification strategy offers an opportunity for greening the energy system, it does not come without substantial challenges. We focus on the use of wind power for the production of hydrogen and derived energy products and, in particular, how framework conditions can be designed to minimise the overall system costs associated with transportation of offshore wind power to producers of green hydrogen and the wider integration into the open wholesale power grid.

Key Danish policy ambitions are at stake. By sticking to "conventional" solutions for system integration, the cost of hydrogen and derived products will remain much higher than their conventional and fossil counterparts, delaying the green transition and making it more costly. By contrast, if Denmark can front run a smart regulatory framework, it will help promote green hydrogen as an increasingly viable option to deal with climate change while also helping job growth in the Danish green cluster, not at least around wind power technologies.

Co-location: a key solution for hydrogen production

One of the keys to a successful integration of increased offshore wind power production is to exploit the potential of co-locating production and consumption of wind power via so-called direct lines, so transmission and distribution via the grid can be bypassed. This is particularly relevant in the context of using wind power to produce e.g. hydrogen, as opposed to serving "traditional" customers, typically spread widely across a given geographical area. This can reduce investments in public grid infrastructure.

The production of hydrogen is in Denmark closely linked to the development of the energy islands. The energy islands are examples of co-location of production and consumption with its own, new challenges.

To illustrate this point, we have created a realistic example of how effective co-location can minimise the need for additional investments in grid infrastructure when building a Power-to-X/hydrogen facility. The hydrogen producer is directly connected to a windfarm and planning production for the hours where power prices tend to be low, e.g., during night-time or other off-peak hours when the pressure in power markets is low. To safeguard against shortfalls of wind power production, it is connected to the open grid, but with a cable of limited capacity given that the facility will only in very few cases lack power from the directly connected windfarm.

The result is a highly desired outcome from a societal point of view: in fact, the hydrogen producer 'imports' power from the grid when capacity in the grid is ample and alternative demand is low. At the same time, the windfarm can deliver surplus power to the grid when demand and prices are high.

Essentially, the connection between the PtX producer and windfarm is designed for balancing purposes rather than transportation of bulk power either to the hydrogen producer or from the windfarm.

The example: A semi-closed system of wind and hydrogen production

In this report, we analyse an example inspired by the Green Fuels for Denmark wind power production facility in the Baltic Sea with 'immediate' connection to a 1.3 GW Power-to-X facility on shore and, hence, in principle almost off-grid. The Power-to-X facility is connected to the grid by a 0.5 GW cable, and to the windfarm by a 2 GW cable. In addition, the windfarm is connected to Germany, making the connection between windfarm and Power-to-X facility in principle an interconnector. We assume a production profile for the Power-to-X facility of 6,000 FLH, running from 23.00 in the evening to 14.00 during the day.

1) Danish Government (2020), Klimaaftale for energi og industri mv. 2020, Dansk Energi (2020), Anbefalinger til en dansk strategi for Power-to-X / 2) Danish government (2022), Udvikling og fremme af brint og grønne brændstoffer (link)

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We analyse how much a semi-closed system consisting of co-located/connected with a direct line wind power production and power consumption for hydrogen production will stress the existing transmission grid infrastructure and capacity. We argue that this 'imbalance' should be the true base for a cost-reflective tariff payment for such a project.

We find that the additional demand from the semi-closed system on top of the existing electricity demand in the grid exceeds total capacity in the grid only in 3 per cent of the hours in a year and hence would induce very limited additional capacity investment costs on the TSO. By carefully planning and locating power production and consumption, (indirect) electrification can happen without driving massive investments in grid transmission capacity.

It is also important to consider how offshore wind (and co-located consumption) can help connect different power markets. Indeed, as windfarms are placed further and further from shore, hybrid connections to multiple prize zones can help ensure that wind power is transported to the areas with the highest demand for power, i.e., serving an interconnector role. Norwegian Stattnett highlights the benefits of hybrid connections to multiple price zones compared to radial connections only to one price zone in its recent report on the development of the Sørlige Nordsjø II wind power area.[1]

The argument can be extended to trade-offs between building new private lines versus using existing/new public infrastructure when discussing co-location of power and PtX installation on land.

Reform of regulatory framework essential: cost-reflective TSO tariffs of the essence

The present tariff framework reflects the historical structure of producers and consumers in the Danish electricity system. Relative to our neighbours, large consumers accounts for a much smaller share of consumption, while the many small consumers have a relative uniform consumption pattern with electricity costs accounting for a very small share of overall costs (either for households or firms).

Consequently, there has been historically relatively limited focus on the role that TSO tariffs play for an effective use of the grid. Notably, having lower tariffs for consumers that impose fewer longer term investment needs on the system because the use the system at hours of low-capacity utilisation.

Hence, an adjustment of the regulatory framework will be key to enable successful transformation of the electricity production and consumption patterns. Notably, a clever regulatory framework and transparent cost signals of transmission capacity use can incentivise investments in production capacity to be geographically located to minimise investments in overall public grid infrastructure.

Ultimately, right incentives can increase the pace and reduce the cost of the green transition. Cost of power, including TSO tariffs, constitute the bulk of hydrogen costs, and the production of derived products is highly price-sensitive. TSO tariffs are a decisive factor for the choice of location of new PtX facilities. TSO tariffs can currently constitute 10[2] to 33 per cent[3] of total PtX production costs in Denmark.

TSOs and regulators, in particular in the countries around the North Sea, recognise the importance of regulatory frameworks and tariff systems fit for purpose to handle both the challenges and opportunities of integrating offshore wind into energy systems. In Denmark, the Energy Agency and the TSO Energinet are currently discussing various options for reforms with stakeholders, including a proposal for an alternative TSO tariff framework.

We compare TSO tariffs in the Nordic region and find that TSO tariffs in all Nordic countries combine volumetric (consumption-based) and capacity-based components, although to a varying degree. In Norway and Sweden, the capacity-based component makes up 95 and 80 per cent, respectively.[4]

In general, flat-rate volumetric tariffs are identified to be the least efficient from an economic point of view because they do not reflect the cost drivers of an electricity grid. The costs of any electricity grid are primarily driven by peak demand. Yet, flat-rate volumetric tariffs do not distinguish between the time of use, and thereby do not give any incentive to reduce peak capacity demand.[5]

1) Stattnett (2022), Fagrapport om havvind I Sørlige Nordsjø II (link) / 2) EA Energy Analyses (2020) Brint og PtX i fremtidens energisystem (link) / 3) Danish Ministry of Climate, Energy and Utilities (2021) Regeringen vil kickstarte udvikling af grønne brændstofer med milliardstøtte (link) / 4) ACER (2019), Practice report on transmission tariff methodologies in Europe / 5) CEER (2017), Electricity Distribution Network Tariffs: CEER Guidelines of Good Practice.

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We conclude that moving towards much more capacity-based TSO tariffs in Denmark will be essential for the development of Power-to-X in Denmark. Indeed, capacity-based tariffs will be low for users with demand for electricity when capacity is ample and power prices are low: this is exactly the most viable set-up for a hydrogen producer.

To put some perspective on the importance of this, we have looked at how much the costs of producing hydrogen would be if Denmark moved towards more capacity-based tariffs. As an example, we have used the tariff systems used in Sweden and the Netherlands that are much more capacity-based and hence also more cost-reflective for a hydrogen producer connected to the grid. In the example, overall costs would reduce to around 3.8 million EUR, or to approximately 1.5 per cent of overall cost of Power-to-X production.[1]

To further reduce tariff payments, the Power-to-X facility could bring down the demand for grid capacity by entering into a contract for interruption, e.g., below 500 MW capacity as in our example. In practice, this would imply that the Power-to-X facility agrees to not stress the grid beyond, say 200 MW, of its maximum capacity when the grid is congested. Hence, interruption would serve to further reduce the link between the semi-closed system of our example and the public grid. This also implies that there is no argument for paying a balancing tariff for semi-closed systems where the connection to the grid is regulated by other instruments.

Cost reflective tariffs the solution to contain tariffs for all customers

More capacity-based tariffs will imply lower tariffs for grid users which inflicts low long-term investment needs on the grid.

But that does *not* mean that other grid users will necessarily have to pay higher tariffs over time. Currently, there is ample capacity notably at night in the grid. New consumers, such as hydrogen producers that make use of this 'spare' capacity, will increase total revenues in the system while only adding marginally to the costs.[2] This would be the case if Denmark adopted a capacity-based TSO tariff of, say, 15 EUR/kW to a hydrogen producer.

By contrast, if Denmark chose to apply above-cost tariffs for hydrogen producers, the demand for this 'spare' capacity may never materialise: production of hydrogen is and will increasingly be highly contested with production located in the countries where the overall system costs are lowest. Hence, expectations of revenue gains from higher tariffs are illusory.

Over time, when more flexible users (hydrogen producers or other type of electricity consumers) are expected to emerge, grid use and capacity is expected to even out compared to the current pattern of peak and off-peak hours (a result of indirect electrification). Also, the overall electricity consumption and capacity of the grid is expected to increase because of direct electrification.[2] In effect, this will reduce the transportation cost of power per user. This also implies that capacity-based tariffs may and should impact differently on different consumer types/sizes, today upon introduction and in the future.

Our basic assessment is that a regulatory regime that encourages more even capacity utilisation and uptake of new customers that do not drive needs for higher investments must be a win-win for all customers. What drives long term tariff costs is not the total level of capacity needed – that will go up to deal with much larger flows as a result of electrification – but the level of capacity utilisation in the grid.

Concretely, we propose to start moving towards a more capacity-based system by creating an "opt-in" regulatory regime lasting 2-4 years targeted at customers with substantial energy consumption at off-peak hours. The idea is to create a "regulatory sandbox" that develops the tools and data to identify the cost drivers in a grid system with different customers with different impact on investment needs and the resulting cost-reflective tariffs. We would expect that the inflow of new customers with low cost impact on the net would in fact lead to an increase in revenues exceed additional costs, allowing a net reduction in tariffs for existing users as suggested by an illustrative example in the report.

Over time, this should lead to a more wholesale reform where all customers are essentially subjected to the same regulatory regime. A general system based on cost reflective tariffs, encouraging movement of use of the grid to hours with spare capacity, would reduce the need to expand the grid as electrification takes off.

In other words, in a longer term perspective the vast bulk of customers would be better of with more cost reflective tariffs.

1) Dansk Energi (2020), Anbefalinger til en dansk strategi for Power-to-X / 2) Andersen et al (2017), Households' hourly electricity consumption and peak demand in Denmark. / 2) See e.g., the discussion paper by the North Sea Wind Power Hub Programme (2021), Integration of offshore wind (link). It mentions a potential next discussion paper to be released: *"The second paper will discuss incentivization of optimal renewable energy (system) usage through market design and regulatory principles"*, p. 3

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Electrification key lever to deliver on climate goals

Rapidly falling costs of wind and solar power...

In many locations with favourable climate and weather conditions, solar and wind power is getting cheaper (see graph to the right) and closer to what has been termed "grid parity": the ability to produce renewable energy at costs equal to or not much above the costs of producing energy from fossil fuels such as coal and gas. There is strong indications that this will continue notably for offshore wind.

...has made electrification strategies highly attractive options to deliver on climate objectives

In conjunction with sharpened global policy focus on the need to address climate change, this has driven interest towards using green power as a key tool often referred to as an "electrification" strategy with two central elements:

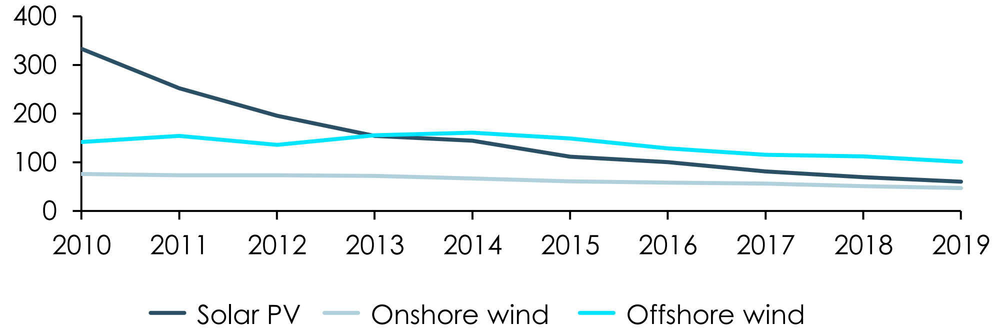
- Direct electrification: notably for road transport (e.g. electric vehicles and rail) or heating (e.g. heat pumps).
- Indirect electrification: notably for the production of hydrogen that can be used either directly in industrial production or as an input for derived products such as ammonia for fertilisers or ship transport.

An electrification strategy is also embedded in Danish projections

The potential of electrification is also demonstrated by projections of energy demand in Denmark over the coming decades. While "traditional" demand is expected to remain largely flat, new sources of demand from direct and indirect electrification may add 136 per cent to electricity consumption in Denmark in 2040, see the graph to the right.

Reduction in cost of producing renewable energy, 2010 – 2019

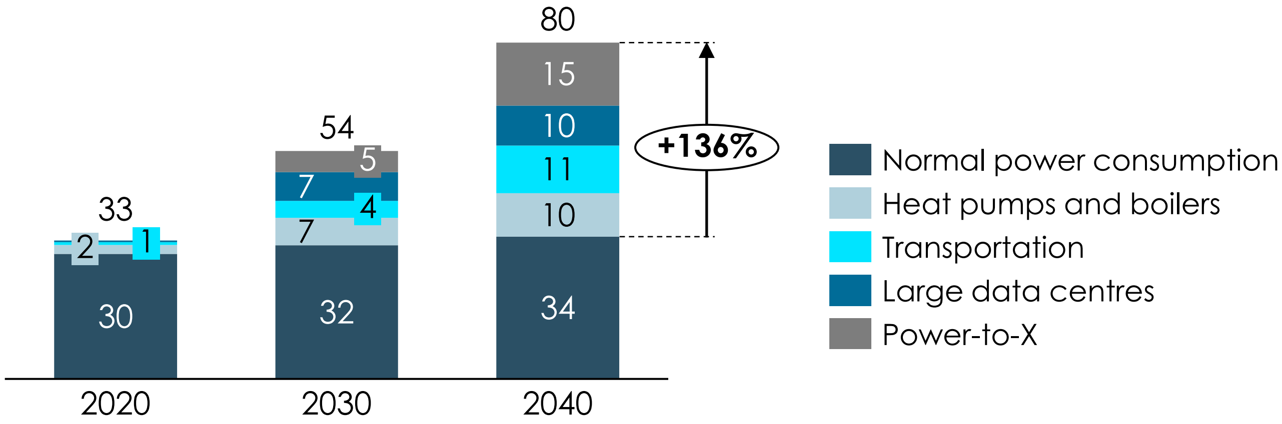
EUR/MWh



Source: IRENA (2019) Renewable power generation costs in 2019 (link)

Consumption of electricity in Denmark, 2020 – 2040

TWh



Source: Danish Energy Authority (2021) Analyseforudsætninger

1) Danish Energy Agency / 2) Danish Energy Agency (2021) Analyseforudsætninger. (A 10 GW North Sea island expansion in not yet considered in the DEA assumptions and calculations. Assumed similar load capacity rate for power plants over time.)

The electrification strategy requires new approaches to grid management and investments

Electrification comes with challenges, not least costs
An electrification approach will challenge grid management policies in three dimensions:

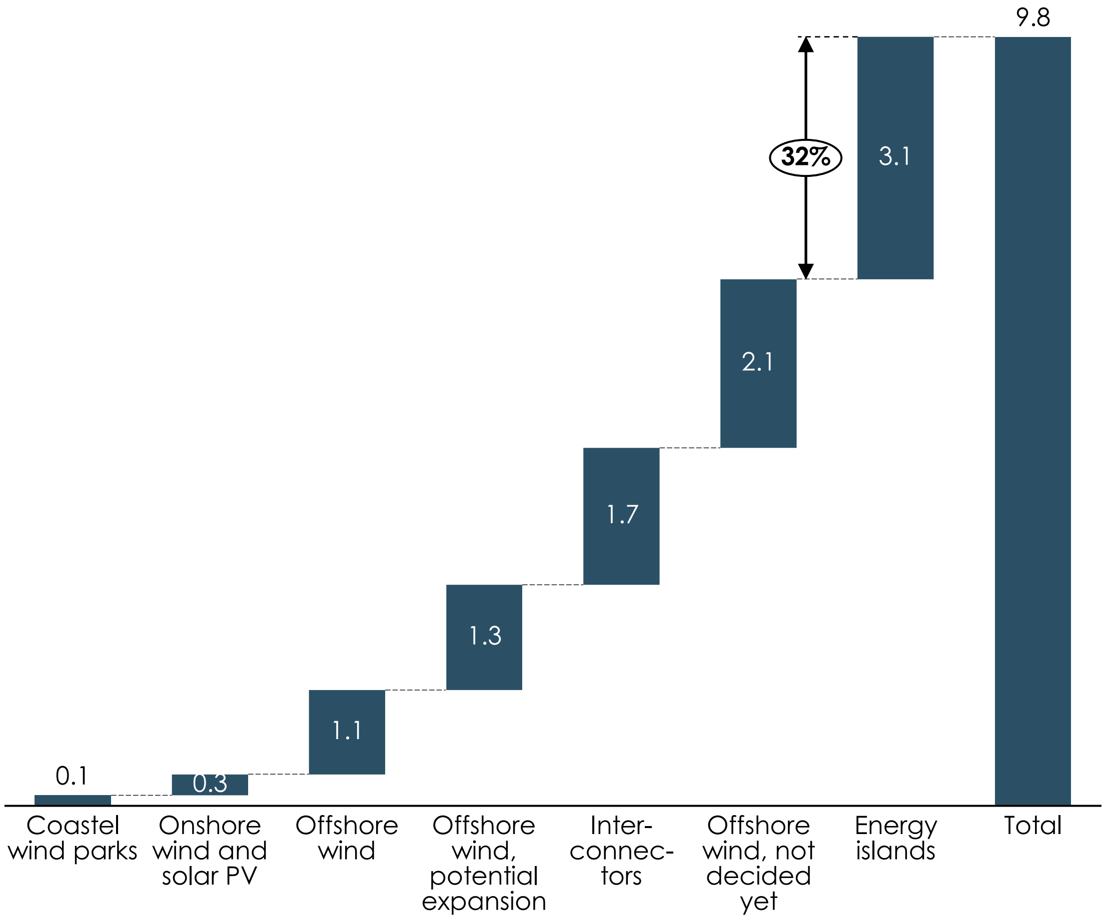
1) Addition of new big power consumers such as producers of hydrogen will require massive amounts of additional power to be transported in the grid.
2) Power production sites of a size that is unseen before (in the GW range) will feed-in electricity in the grid, e.g. the Danish energy islands.
3) A higher share of intermittent power will, all other things equal, increase imbalances between demand and supply both in the TSO and DSO grid.

The problem is that the current regulation drives TSOs to build out the electricity grid to deal with peak loads rather than incentivising grid operators and consumers to flatten consumer demand over the day, week, and between seasons.

A "smart grid" as the solution
The difference in costs between the traditional and the "smart grid" solutions increasingly become clear:

- *DSOs*: smarter regulation of DSOs, including more digital solutions could save 40-140 billion EUR for EU consumers relative to business-as-usual solutions.[2]
- *Hydrogen*: co-location or clusters: by placing the production of power closer to the consumption of power, the need for infrastructure investments can be markedly decreased. **We focus on the hydrogen argument in this project.**

Transmission grid investments needed towards 2040
Billion EUR



Source: Rambøll (2021) En analyse af investeringer, nettab og det fremtidige energisystem

Source: 1) Rambøll (2021) En analyse af investeringer, nettab og det fremtidige energisystem (link) / 2) Eurelectric (2021) Connecting the dots: Distribution grid investments to power the energy transition (link)

Wider societal impact: green growth, competitiveness, and energy security

Hydrogen will replace oil and gas as a prime energy commodity

Todays global trade in energy commodities is dominated by oil, gas and coal. In a net-zero world, they will be replaced by electricity, hydrogen and derived products such as ammonia based on hydrogen production, see graph to the right.

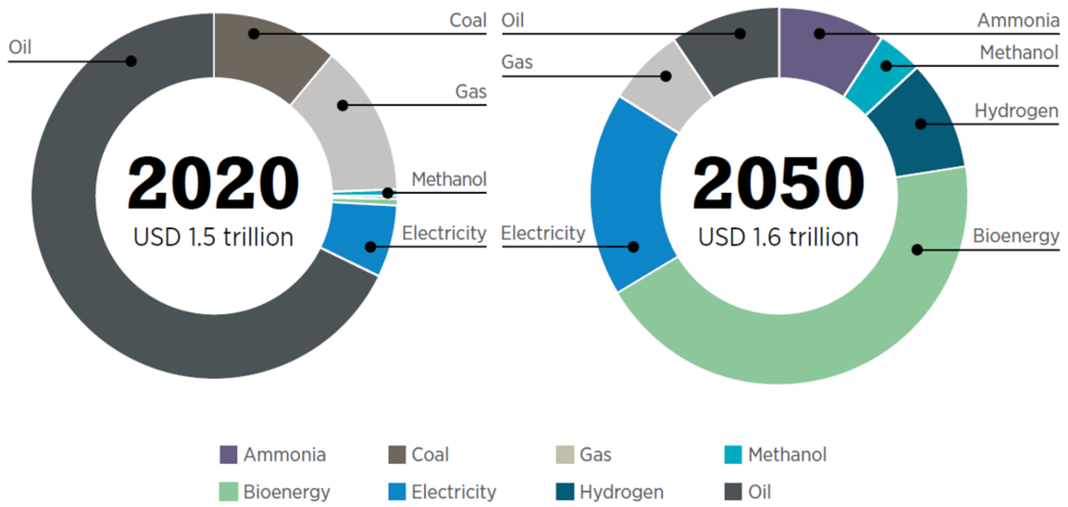
Hydrogen can become an important economic area for Denmark

Within the EU, we are likely to see the production of hydrogen in fierce competition based on electricity supply from North Sea offshore power and sun and wind sources in the Mediterranean region.

The EU, and Denmark in particular, can become a player in the hydrogen production environment, in particular by its energy island plans, but it requires a very diligent approach to the overall regulation where costs are being held low throughout the value chain. In March 2022, the Danish government realised the Power-to-X agreement for Denmark, which aims at developing 4-6 GW of electrolysis capacity before 2030 and emphasises the role of PtX in the Danish carbon neutrality pathway.[1]

Shifts in the value of trade in energy commodities, 2020 to 2050

USD



Source: IRENA (2022) Geopolitics of the Energy Transformation (link)

What is at stake for Denmark?

1. Speeding up the process of electrification & quicker realisation of emission reductions
2. Starting up the hydrogen industry in Denmark that has high relevance for the Danish economy
3. Green hydrogen boosting demand for wind power, a key industrial cluster for Denmark[2]
4. Job creation in regions of Denmark with relative modest alternative job opportunities
5. Energy security and independence of gas for electricity production and heating

1) Danish government (2022), Udvikling og fremme af brint og grønne brændstoffer (link) / 2) The wind industry in Denmark employs around 2.3 per cent of all Danish employees, see Wind Denmark industry statistics 2018

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Co-location can integrate power with limited impact on the grid

The energy landscape in Denmark is changing

The Danish energy landscape is characterised by many small producers and consumers, and there are essentially no big industrial users of electricity in Denmark. Paying for the use of the electricity grid according to the electricity consumed has hence covered the TSO costs appropriately. However, this energy landscape is undergoing a large change with many large producers and consumers joining that have other supply and demand patterns.

Co-location can curb large public investments in grid infrastructure

Direct lines connecting power production and consumption outside the grid, i.e., via private lines that are parallel to the transmission grid, are currently not allowed. The argument has for a long time been to avoid duplication of costs and to ensure an efficient use of public infrastructure that is the grid. This means that to connect and make use of, e.g., offshore wind, a connection from the windfarm to the grid is to be made *and* a connection from the grid to the power consuming unit.

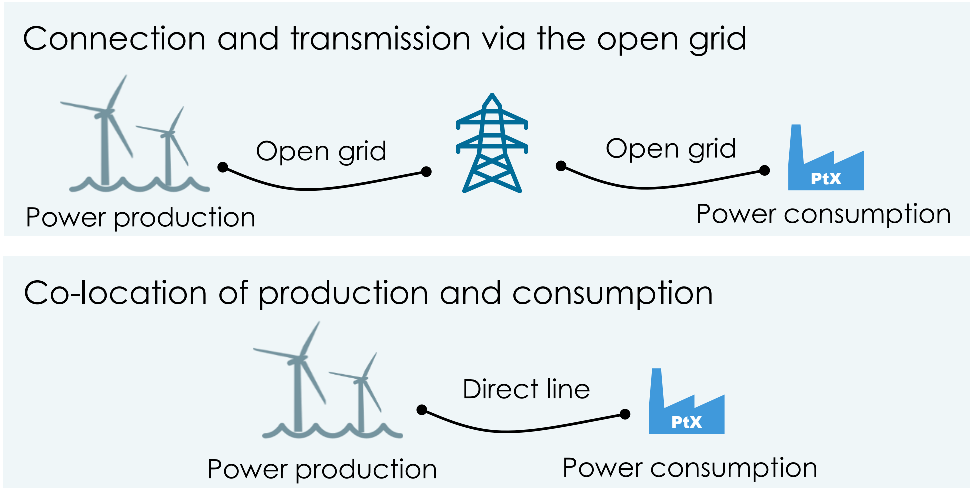
In addition, electrolysis or hydrogen production is found to be the most flexible among new large consumer types (compared to data centres or heat pumps that are inflexible in their electricity use), not just from a production point of view, but also from a grid expansion perspective.[1]

The semi-closed system has a balancing functionality

In this report, we analyse a semi-closed system of an offshore windfarm connected with a direct line to an electrolyser at shore, with a limited connection to the grid, see the next slide for a more detailed description.

Due to this design, the hydrogen producer 'imports' power from the grid when capacity in the grid is ample and alternative demand is low. When the opposite situation occurs, the windfarm can deliver surplus power to the grid when demand and prices are high. The connection between the hydrogen producer and windfarm offers an opportunity for balancing with the grid.

Co-location and direct lines



Source: Copenhagen Economics

Co-location can reduce transmission grid costs

> What could change the need for transmission grids is if the possibility to use direct lines (and the resulting benefits for TSOs) provides an incentive for a higher degree of geographic co-location of new consumption/production in the transmission network. A higher degree of co-location of consumption and production would reduce the need for long power transmissions and would thus - all else equal - also reduce the need for transmission infrastructure.
>
> This will be the thesis of this analysis and it is the consequences of such an assumed co-location effect of the possibility (to some extent) to use direct lines that are examined.

Source: Energinet (2021) Konsekvensanalyse af mulighed for direkte linjer på transmissionnettet, p. 6.

1) Energinet (2021) Konsekvensanalyse af mulighed for direkte linjer på transmissionnettet

An example of co-location of wind power and Power-to-X

We use an example inspired by the Green Fuels for Denmark project to showcase the impact of capacity-based tariffs

In this report, we look at a semi-closed system constituted by a privately owned 2 GW windfarm in the Baltic Sea, a cable transporting the electricity to an onshore 1.3 GW Power-to-X (PtX) facility as the main off taker of the electricity. The semi-closed system is connected to the open electricity grid DK2 by a cable restricted to 500 MW. The prime purpose of the windfarm is to supply the PtX facility. Only in hours with low wind power production, the facility will draw electricity from the open grid. The PtX facility runs for 6,000 full load hours a year.

The example is inspired by the Green Fuels for Denmark project in order to make the example realistic, but the results hold general implications.

Three connections are relevant in this example

In our example there are three cables or connection points; one connecting the PtX facility to the grid (1), one connecting the wind farm to the PtX facility (2) and one connecting the wind farm to Germany (3), see the illustration below.

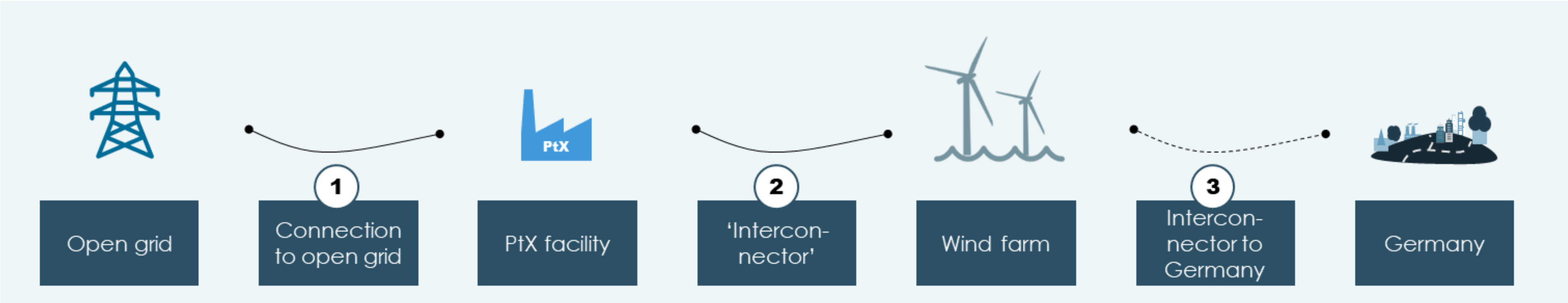
The aim of the analysis is first and foremost to understand the implications that this semi-closed system has on the existing grid, by taking a *marginal approach*. We look at how much additional capacity demand the PtX facility will impose on the grid in a given

year through cable (1) as an expression of the costs imposed on the grid from the semi-closed system.

For cable (2) we assume that the cost and tariffs associated with the cable accrue to the wind farm owner (and may be shared between seller and buyer of the wind in a standard commercial contract).

Cable (3) connects the wind farm to Germany, but we exclude this initially assuming we are dealing with only price zone. However, given the combination of (2) and (3) there may be additional tariff revenues to be reaped for the TSO in the case that power is exported to Germany. This falls outside the scope of this report.

An illustrative example of a semi-closed system



Source: Copenhagen Economics

Very limited demand impact on grid capacity from the PtX facility in co-location with the windfarm

The cost-minimising production hours are during night time

Using current electricity prices in DK2, we find that the cost-minimising production window during a day for a 1.3 GW PtX facility at 6,000 full load hours (FLH) production in co-location with a 2 GW windfarm starts at 23.00 at night and lasts until 14.00 in the afternoon, see graph to the right. These are the hours where aggregated electricity prices are lowest and the pressure on the transmission grid is low.

Use of grid power in hours where the wind farm cannot deliver needed capacity

We establish in which hours of the year the wind farm produces sufficient electricity to supply the PtX facility and in which hours the PtX facility needs to draw electricity from the open grid. In the hours where the PtX facility draws from the open grid, it stresses the open grid additional to already existing capacity demand from other users.

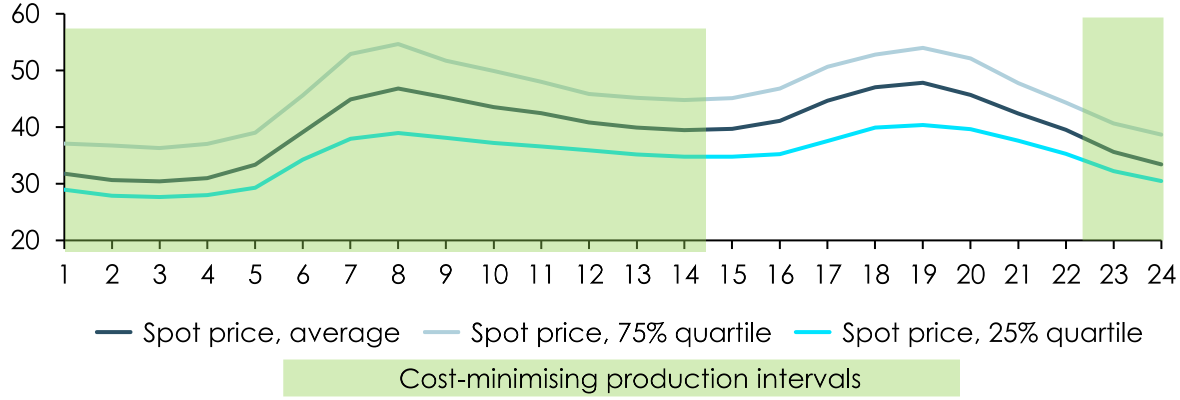
Additional demand from the PtX facility rarely stresses the open grid beyond existing capacity

We identify the hours in which the current capacity demand in DK2 plus the requested additional capacity from the PtX facility exceeds the maximum capacity in the open grid DK2[1]. In co-location, this is the case in 260 of 8,760 hours a year, or only 3 per cent of the time, see graph to the right.[2] If placed directly in the open grid, the total demand would exceed maximum capacity in the open grid in *almost all hours* in a year.

In the peak load hour, total capacity demand in DK2 would reach 370 MW beyond the maximum capacity available in DK2 in the co-location example vs. 1,300 MW with direct placement in the open grid.

Cost-minimising PtX production window for 6,000 FLH production profile

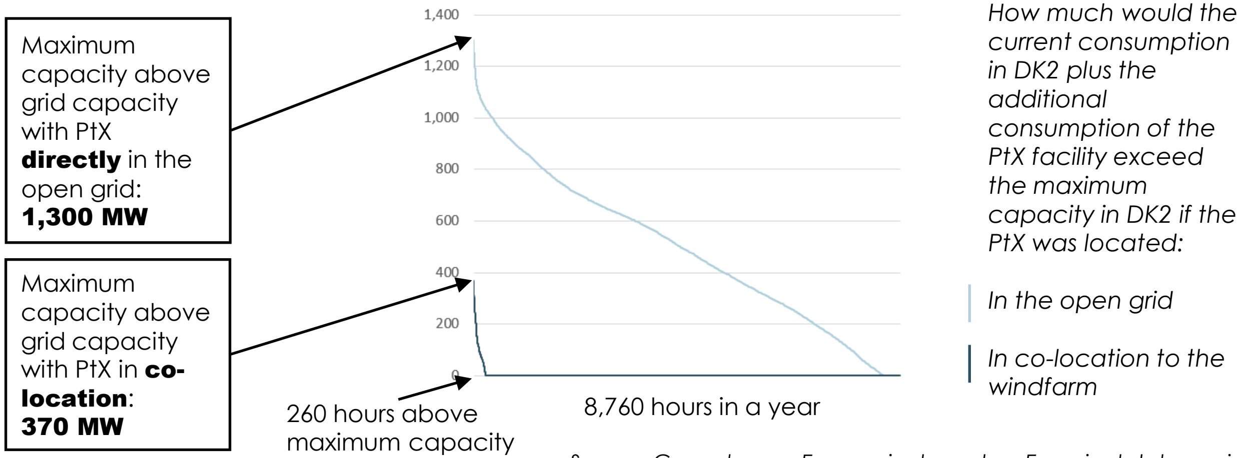
EUR/MWh



Source: Copenhagen Economics based on Energinet, Day ahead spot prices 2019 (link); Energy Analysis (2020), Brint og PtX i fremtidens energisystem; Danish Energy Agency (2021), Analyseforudsætninger (link)

PtX capacity demand exceeding maximum capacity in DK2 – directly and in co-location

MW



Source: Copenhagen Economics based on Energinet data service

1) We define maximum capacity in DK2 as the consumption in the hour in 2019 where consumption was highest, i.e. 2,335 MW. / 2) Energinet itself uses this approach to examine the total stress on its grid, see e.g. Energinet (2021) Behov for begrænsning af produktion i DK2 syd som følge af VE-udbygning (link)

A contract for interruption can cap capacity demand even further

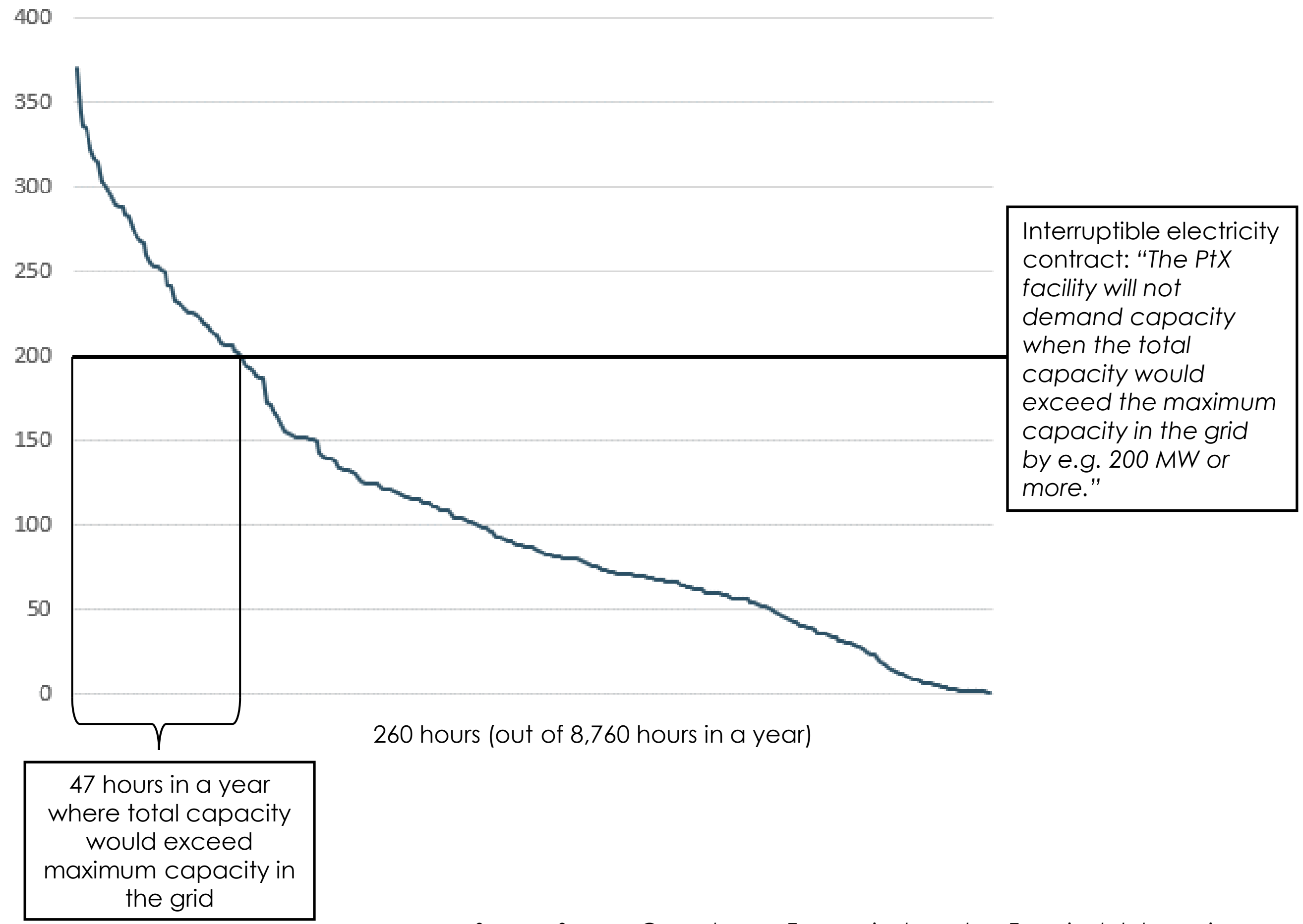
The peak capacity in the grid ultimately determines the size of the grid
The demanded capacity from grid users in the peak or most congested hour determines the relevant size or capacity of the total grid. If the grid capacity was lower than the peak demanded capacity, the demand could not be met. If the grid capacity was higher than the peak demanded capacity, there would be spare capacity in the grid, which is not socio-economically optimal.

An interruptible electricity contract can limit the peak capacity in the grid
If a grid user limits itself to a maximum capacity demand during high-demand hours which is below its otherwise demanded capacity, this reduces the relevant size of the grid needed.

In our example to the right, the interruptible electricity contract could limit the PtX facility not to demand capacity when the total capacity demand already exceeds the maximum available capacity by a certain limit. For the purpose of illustration, we here show a limit at 200 MW beyond the maximum capacity of the grid.

Such interruptible electricity contracts bear cost savings for the TSO and avoid extensive spare capacity in the grid. Hence, the contracts include a rebate or otherwise lower tariff for the grid user.[1]

PtX capacity demand capped by an interruptible electricity contract
MW



Source: Source: Copenhagen Economics based on Energinet data service

1) ACER (2019) Practice report on transmission tariff methodologies in Europe

Effective use of existing infrastructure versus parallel direct lines

Moving from radially connected wind parks to more integrated energy systems

It is clear that co-location with direct lines from a wind park to an electrolyser can be a smarter option than building a line to the open grid that is in turn connected to an electrolyser.

But there is also a potential case for building so-called interconnectors between the wind park and multiple other price zones. A connection to Germany could be relevant in our illustrative example. Norwegian Stattnett highlights the benefits of hybrid connections to multiple price zones compared to radial connections only to one price zone in its recent report on the development of the Sørlige Nordsjø II wind power area.[1]

Such interconnectors have multiple benefits

For the electrolyser:
In situations of too little wind power production from the wind park, production constraints could be mitigated by importing power from Germany. These situations are likely to arise when prices are high in DK2 all other things equal and power is moving from Germany to Denmark.

For the wind park owner:
Access to multiple price zones should increase average prices as the wind park owner can choose to sell surplus power, having fulfilled contractual obligations with the electrolyser, to the highest bidder. This will lower capital costs which ultimately also benefits the electrolyser as main customer. It is essential that the electrolyser and the wind park owner don't pay twice for the use of the interconnector.

For the overall Danish grid/the TSO:
Traditionally, the business case for building an interconnector is based on the income from electricity trade on the interconnector. If the interconnector connects a semi-closed system, the payments for this connection constitute an additional revenue stream.

The semi-closed system with the wind park could arguably tip the decision over to build the interconnector. This suggests that the merits of using wind parks as vehicle to connect price zones is a chance to increase the value for an operator of a given seabed.

For society:
Interconnectors are public infrastructure and fulfil multiple purposes, such as power exchange with other price areas, but also connecting a producer and consumer in a semi-closed system. Interconnectors can hence eliminate the need for additional direct lines parallel to the open grid. This reduces the costs otherwise incurred with building and operating parallel direct lines.[2] Effectively using interconnectors and avoiding parallel infrastructure has large socioeconomic benefits.

The double functionality of such public infrastructure calls for user payments that set the right incentives to materialise the socioeconomic advantages. This is relevant both in the context of infrastructure around energy islands but also the use of the existing infrastructure on land as opposed to building parallel direct lines on land.

The key driver of the right mix between public and private infrastructure is the tariff structure. This requires that tariffs are cost reflective, i.e. determined by the short and long term cost drivers associated with linking operators to the public.

An illustrative example of an interconnection to other price zones

1) Stattnett (2022), Fagrapport om havvind I Sørlige Nordsjø II (link) / 2) Danish Energy Agency (2021) Analyse af geografisk differentierede forbrugstariffer og direkte linjer

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Incentives to locate and invest are guided by price signals from the TSO

Tariffs affect consumer behaviour and use of electricity

The tariffs that consumers and producers of electricity pay for access to the grid are central for how it is being used: notably how to ensure it is being used with the largest benefits to society.

Efficient tariffs, i.e. tariffs provide the best economic incentives to undertake socio-economically optimal investments, should have substantial capacity-based elements. Under capacity-based tariffs, users pay for how they affect the need for capacity in the grid. The basic reason is that is the main driver of costs in a TSO grid is investments.[1]

Capacity-based tariffs create cost-reflective incentives

Capacity-based tariffs reflect the maximum (expected or contracted) capacity demand of the grid user and grid users are thus incentivised to distribute electricity consumption more evenly during the day or geographically, dependent on the tariff system, as it reduces the need for high capacity connections (and hence tariffs costs).

Changes are underway

Energinet, the Danish TSO, is in the process of reviewing the current TSO tariffs. It proposes to update the system tariff to contain a fixed subscription-style tariff and reduce the volumetric component accordingly, while at the same time integrating the balancing tariff into the system tariff.

Besides, Energinet has signalled a wish to include also a capacity-based element to replace the existing transmission grid tariff, which is also to be differentiated in time of use and geographical location of capacity demand. However, tariff levels have not yet been proposed, see fact box on the next page.

Capacity-based tariffs in our illustrative example

We have seen that the electrolyser stresses the public grid in only very few hours and only with low capacity demand. There is almost no need to expand the public grid to accommodate this demand, which can be even further reduced by a contract for interruption. Hence, a capacity-based tariff will be very low if it reflects the additional costs to the TSO imposed by the semi-closed system.

TSO tariff components in the Nordic countries

Country	Volumetric tariff	Capacity-based tariff
Denmark	✓	✗
Sweden	✓	✓
Norway	✓	✓
Finland	✓	✓

Source: Copenhagen Economics based on ACER (2019) Practice report on transmission tariff methodologies in Europe, table 9

1) CEER (2017) Electricity Distribution Network Tariffs - CEER Guidelines of Good Practice

A move towards capacity-based tariffs leads to more cost-reflective tariffs for PtX production

Peak capacity demand determines grid investment needs

The total capacity demand in the most congested hour determines the total capacity required in the open grid. It is thus exactly this peak load that determines the investment needs for Energinet. A capacity-based grid tariff reflects the peak capacity demand in the open grid.

The tariffs charged to large, additional users do not require a system tariff component, as these users operationalise for the most part (97 per cent) spare capacity in the open grid during off-peak hours. In short, a PtX facility has a low impact on investment needs in the TSO grid, certainly given the current consumption pattern in the Danish grid.

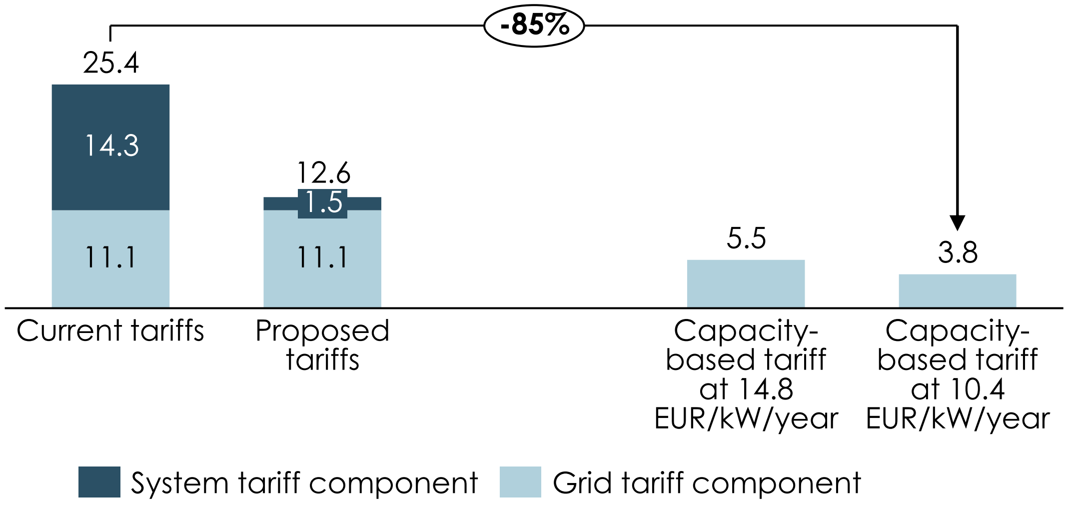
Total costs for the PtX facility decrease at capacity-based tariffs

We compare the total costs from TSO tariffs at current, proposed, and capacity-based tariffs for a consumer with a high demand. Solely for the purpose of illustration, we have here chosen to calculate total costs from tariffs for two grid tariff levels: 1) Tariffs used in Energinet's calculations as well as the average capacity-based tariff in Sweden at 10.4 EUR/kW/year[1,2], and 2) tariffs in the Netherlands at 14.8 EUR/kW/year[3]. However, any other reasonably capacity-based tariff would yield similar results.

The total costs for the PtX facility are highest under current tariffs, while they are somewhat lower under the proposed tariffs. For any reasonable capacity-based tariffs, total cost would fall substantially, e.g. 85 per cent from current tariffs to the capacity-based tariffs used by Energinet, see graph to the right. This decreases the share of TSO tariffs in the cost for PtX production from 10.2 to around 1.5 per cent.

Total costs for capacity demand at current, proposed, and cost-reflective tariffs

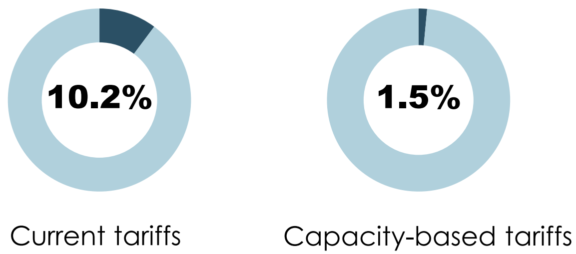
mEUR per year



Note: Costs at capacity-based tariffs calculated from the maximum additional capacity demand above the maximum grid capacity in DK2 of 370 MW and the introduced capacity-based tariffs in DK, SE, and NL.
Source: Energinet tariffs (link); TenneT tariffs in the Netherlands (link)

Share of TSO tariff in total PtX production costs at 6,000 FLH production

Per cent



Source: Copenhagen Economics based on EA Energy Analyses (2020) Brint og PtX i fremtidens energisystem (link)

1) Energinet (2021) Konsekvensanalyse af mulighed for direkte linjer på transmissionsnettet / 2) Svenska kraftnät (2022) Prislista (link) / 3) TenneT tariffs in the Netherlands (link)

Fact box

Current TSO tariffs in Denmark and proposed changes

Current TSO tariffs in Denmark for consumers of electricity

Name	Cost recovery	Tariff	Energinet revenue
Transmission grid tariff	Covers costs related to interest and depreciation on the transmission network and its operation and maintenance, Energinet operations and net losses	6.58 EUR/MWh	202 mEUR/year
System tariff	Covers costs for security of supply and quality of electricity supply including reserve capacity, system services, and DataHub	8.19 EUR/MWh	267 mEUR/year
Balancing tariff	Covers a share of Energinet's total costs for system services and balance market management	0.31 EUR/MWh	-

Source: Energinet website (link); Energinet (2021) Konsekvensanalyse af mulighed for direkte linjer på transmissionsnettet

Proposed changes by Energinet to the TSO tariffs in Denmark

Name	Proposed change	Tariff
Transmission grid tariff	**Capacity-based;** **Time differentiated** (low-price window at night); **Contracts for interruption;** **Geographically differentiated**	**?**/MW Energinet has not yet suggested a level
System tariff	• Reduces according to introduction subscription fee (25-30 per cent); • **Large consumers (over 100 GWh annually) pay reduced tariff at 10%;** • Now includes balancing tariff	5.77 EUR/MWh + 0.31 EUR/MWh *Above 100 GWh annually* *0.58 EUR/MWh* *+* *0.31 EUR/MWh*
Balancing tariff	Included in system tariff	-

Source: Energinet website (link); Energinet (2021) Høringsudgave – Revideret opkrævningsmodel for systemtariffen

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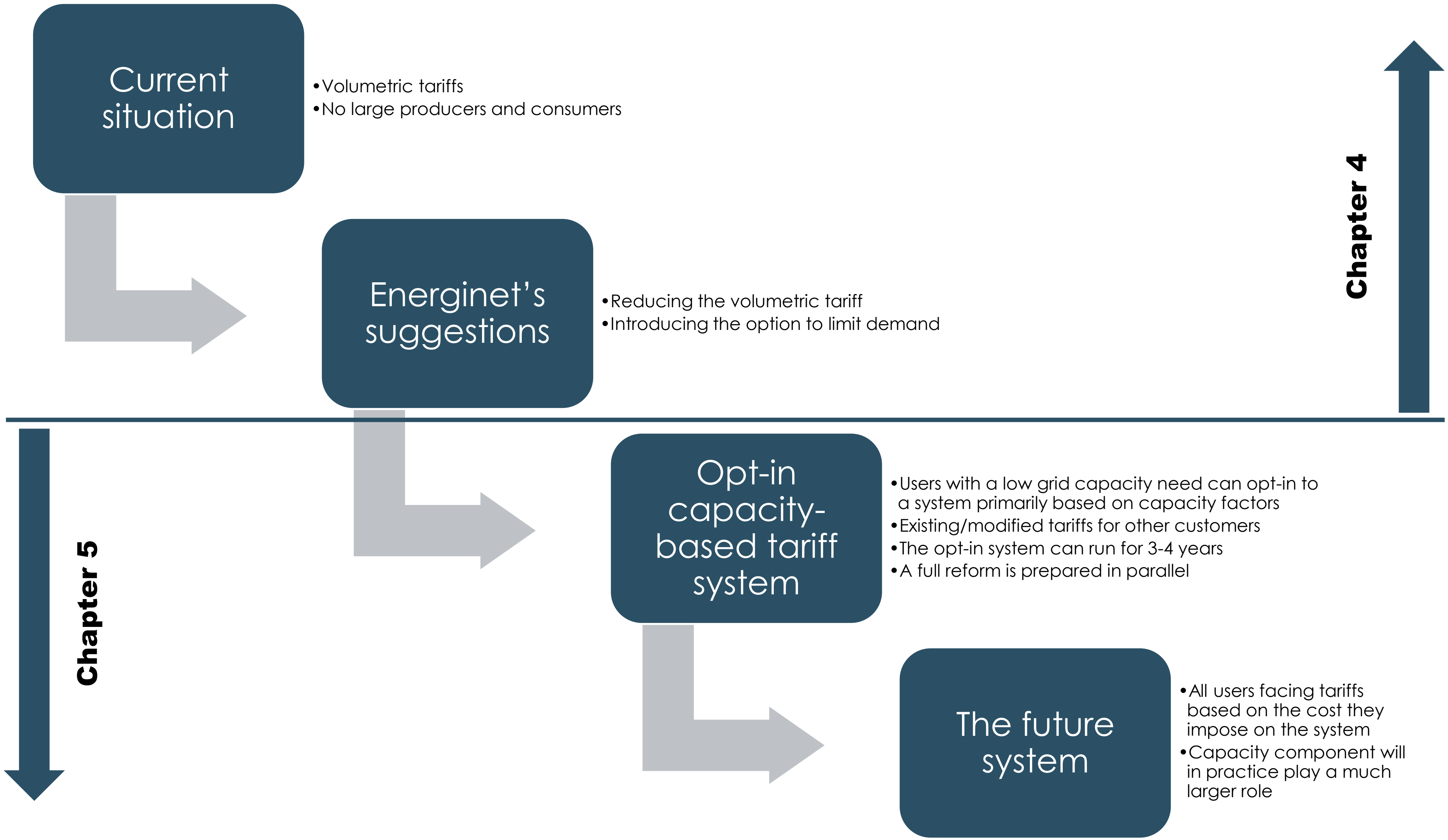
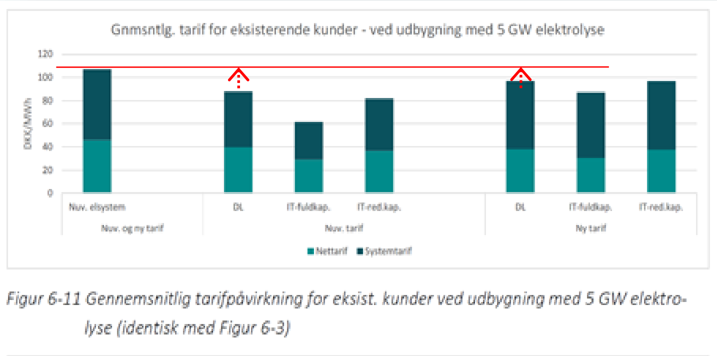
We are on a reform path, but need to move further



The 'opt-in' regime can introduce capacity-based tariffs

The opt-in regime allows large producers and consumers to use spare capacity in the grid

- Power-to-X producers represent new, atypical demand (primarily in off-peak hours with low capacity utilisation)
- Ample spare capacity in the open grid can be used by large hydrogen producers
- A cost-reflective tariff system, based on capacity-based tariffs can create the right incentives to use spare capacity
- We observe that Energinet and other TSOs are introducing capacity-based tariff components
- We suggest an opt-in regime with capacity-based tariffs that is more cost-reflective in the long run, see also fact box on page 26
- The opt-in regime is non-discriminatory and leads to a gradual phase-in of capacity-based tariffs
- The tariff system will need to ensure stability for existing hydrogen producers/first movers by long contracts, slow phase-in of tariff increases or similar ("grandfathering")
- The system to operate perhaps 2-4 years while awaiting and preparing the full reform

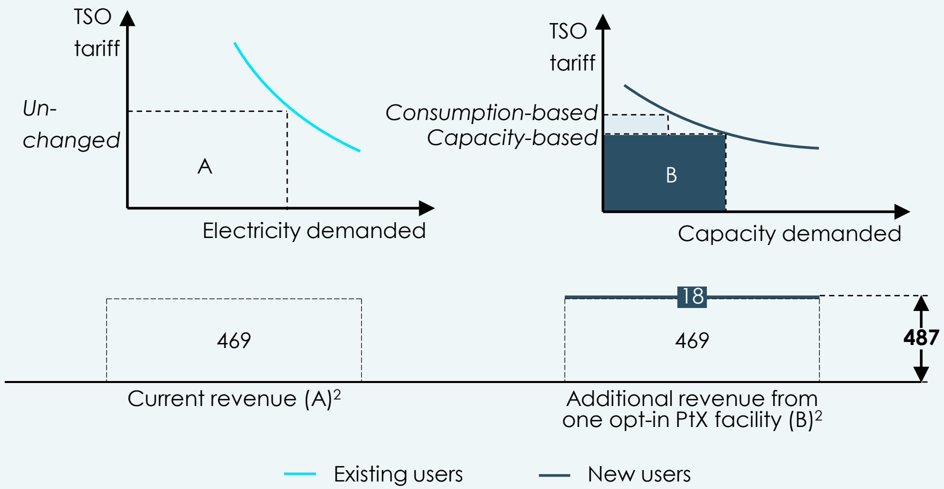


Figur 6-11 Gennemsnitlig tarifpåvirkning for eksist. kunder ved udbygning med 5 GW elektrolyse (identisk med Figur 6-3)

The opt-in regime will generate additional revenue for the TSO

- Semi-closed systems have a limited impact on overall grid costs
- Even more limited with contracts for interruption/limited grid access in place
- Connection with hydrogen producers create additional revenue for TSO, *without additional need to expand the grid*, because they "only" use spare capacity for a foreseeable future
- Assuming that there is hence no need to expand the grid and no additional investment cost to the TSO, overall TSO revenue will *increase* upon entry of hydrogen producers. We here use 6 GW hydrogen production.
- The additional TSO revenue can potentially be used to reduce overall tariffs for other users (cross-subsidise)

Revenue from existing users | **Additional revenue from opt-in to capacity-based tariffs for new users**

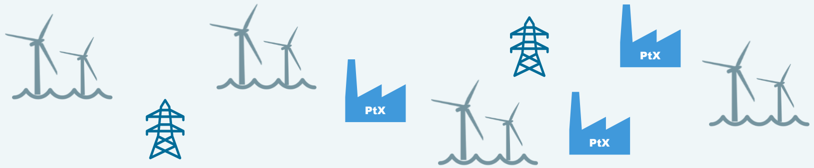


Note: Energinet's tariff analysis does not 1:1 correspond to ours. The proposal here could be a refinement of Energinet's analysis.

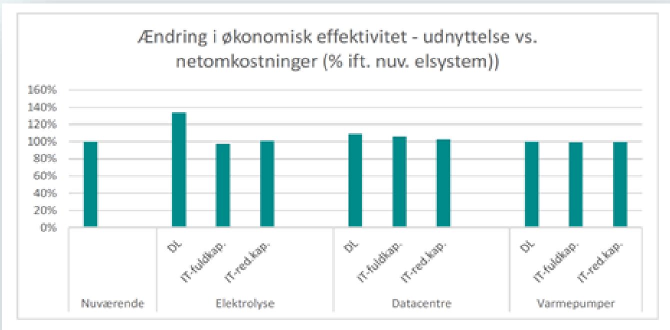
Source: Snippets from Energinet (2021) Konsekvensanalyse af mulighed for direkte linjer på transmissionsnettet.

In the future system, users pay for the costs they impose

The future system is characterised by cost-reflective tariffs



- More off-peak usage smoothens capacity utilisation
- Grid users are defined by capacity requirements rather than volume consumed to ensure non-discrimination
- The future system is characterised by genuine full capacity-based tariffs for all users (this requires thorough analysis)
- New users will pay according to their peak capacity demand
- Eventual costs for more capacity needs will be covered by cost-reflective tariffs

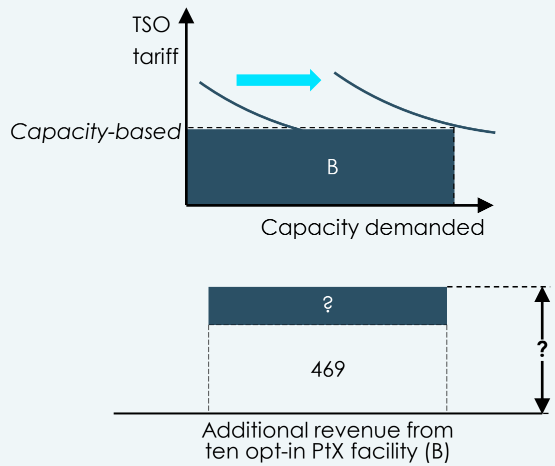


Figur 6-10 Økonomisk effektivitet af samlet elsystem

Cost reflective tariffs as means to contain tariffs for all customers

- Higher utilisation of grid and less spare capacity, implying lower transportation costs per unit for all customers
- New hydrogen producers increase the revenue for the TSO, but may also give rise to new grid costs, depending on geographical location, production profile, connection to grid etc.
- As a result, tariff payments for new hydrogen producers may rise, see also the fact box on the next page
- However, capacity-based tariffs reflect exactly the additional cost the additional demand imposes on the TSO
- Overall, the move towards more capacity based tariffs will help move utilisation away from hours of peak capacity. This could substantially reduce the need to increase the grid as electrification increases the overall production and distribution of electricity.
- In a long perspective, it is highly likely that the vast bulk of customers will benefit from such a move.

Additional revenue from multiple new users



Source: 1) See e.g. link / 2) Copenhagen Economics, see appendix

Fact box

Who should pay which tariffs to cover which costs and how will tariff levels change under capacity-based tariffs?

Change in capacity-based TSO tariffs applicable to existing and new users today and in the future

		Transmission grid tariff	System tariff	Balancing tariff
		Cover costs related to interest and depreciation on the transmission grid, operation and maintenance, Energinet operations, and grid loss	Covers costs for security of supply and quality of electricity supply including reserve capacity, system services, and DataHub	Covers a share of Energinet's total costs for system services and balance market management
Today	Existing users	↓ Less or unchanged	→ Unchanged	→ Unchanged
	New users	↓ Use spare capacity	✗ Not applicable	✗ Not applicable
Future (high capacity utilisation)	Existing users (small)	→ Unchanged or higher	↑ Will increase with higher system costs	→ Unchanged
	Existing users (large)	→ Unchanged due to 'grandfathering' or higher cost due to higher capacity utilisation	↑ Will increase with higher system costs	↑ Total load in the grid is in all hours closer to the maximum grid capacity and balancing services may be relevant
	New users (large)	↑ Higher cost due to higher capacity utilisation	↑ Additional demand may require grid expansion	↑ Total load in the grid is in all hours closer to the maximum grid capacity and balancing services may be relevant
	TSO revenues	↑ **Higher cost covered by larger tariffs**	↑ **Higher cost covered by larger tariffs**	↑ **Higher cost covered by larger tariff**

↓ TSO tariff may decrease → TSO tariff may remain unchanged ↑ TSO tariff may increase

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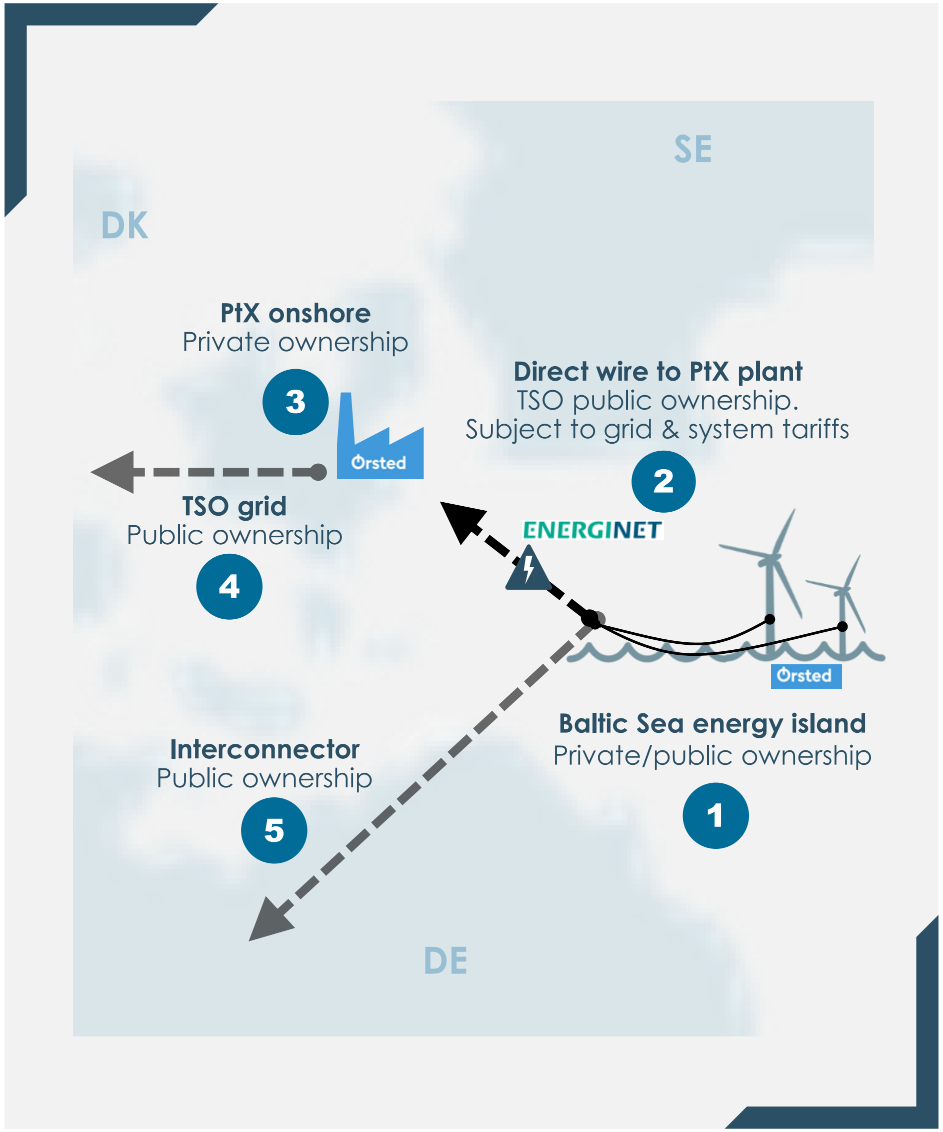
An illustrative example inspired by Green Fuels for Denmark



Five different elements make part of the project as depicted to the right. We make the following assumptions on each of these elements:

1	**Baltic Sea energy island**	• Expected capacity in 2030: 2 GW • Hourly capacity factors of energy island same as total wind energy production profile in DK2 in 2019
2	**Direct wire to PtX plant**	• Large enough to carry maximum generation capacity, i.e. 2 GW • Additional cost of direct wire determined by the equivalent costs for the capacity usage
3	**PtX on-shore**	• Production profile at 6,000, FLH per year at 1,300 MW • Produces in the cost-minimising consecutive hours throughout the day
4	**TSO grid**	• If power production exceeds PtX production, electricity flows into the open grid and vice versa • Connection of the power and PtX production entity to the open grid limited to 500 MW
5	**Inter-con-nector**	• Remaining electricity that exceeds the capacity of the connection to the open grid can be exported/imported via an interconnector to e.g. Germany

Assumed production profile for the energy island

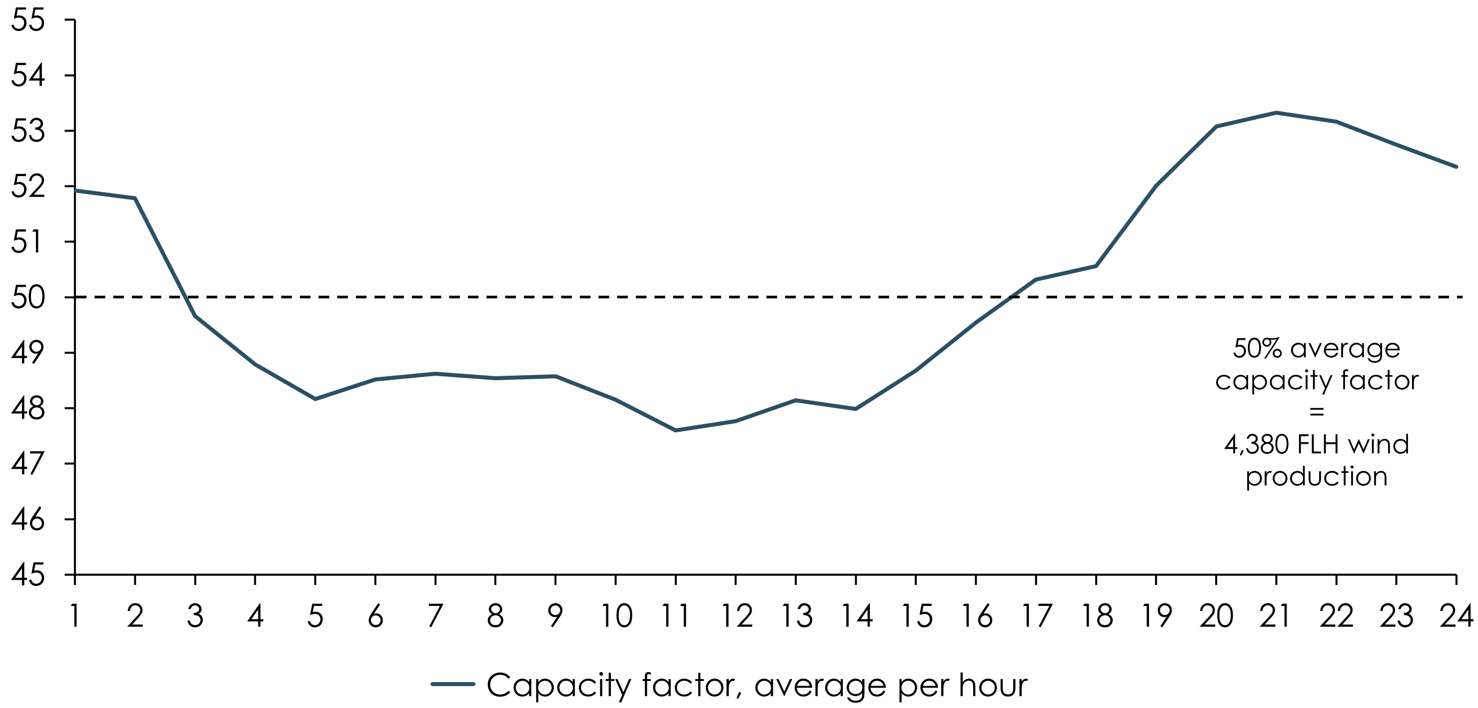
The main input for modelling the energy island wind production is the **offshore wind production profile.** We here consult the actual offshore wind production in DK2 in 2019.

We use the **average capacity factors per hour of the day and scale these up to an average capacity factor of 50 per cent** (as stated in the ENS technology catalogue)[1] to determine the expected production of the energy island.

The 2 GW wind farm supplies the 1.3 GW Power-to-X production facility that runs for 6,000 FLH per year.

Average capacity factors offshore wind production in DK2 in 2019

Per cent



This graph shows the average capacity factors for offshore wind production in DK2 in 2019, calculated from actual production in 2019 and the maximum offshore wind production capacity in DK2 in 2019 of 444.4 MW and scaled up to an average of 50 per cent.

The average capacity factor of 50 per cent is equivalent to 4,380 FLH of the wind farm.

1) ENS teknologikatalog (link)

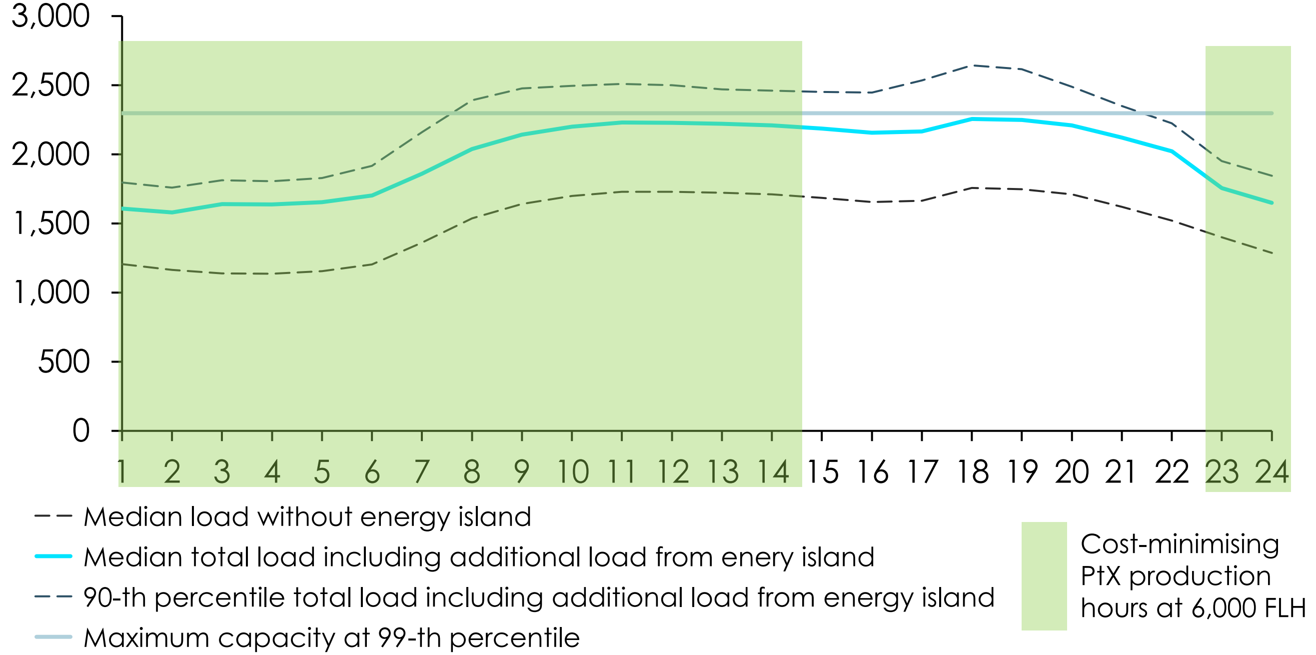
On average, the additional flows from the open grid to the PtX production facility rarely stress capacity

To determine the additional cost to the electricity grid from installing a connection between the wind power and PtX production entity to the open grid, we look at the **additional load in the open grid from this connection.** This connection is restricted to 500 MW.

We then **compare the additional stress on the open grid to the maximum capacity in DK2** and establish that the median total load including the additional load from the entity does not exceed the maximum capacity in any hour, but **comes close during the hours of excess wind production.** Hence, the PtX production facility does not stress the grid, but **additional electricity is available during peak capacity hours,** e.g. for the wider electrification.

Total load in DK2 including additional load from PtX production and energy island wind production compared to maximum capacity

MW



The median total load including additional load from the energy island **comes closest to the maximum capacity during the excess wind production hours** (e.g. at 18.00).

Hence, there is pressure on the capacity of the open grid from outflows into the grid when power consumption is high, and this is not really relevant for a PtX tariff discussion: we do need more power to deliver on direct electrification, and **we need it when consumers have the highest willingness to pay.** This ultimately requires higher capacity, but this **increased demand is not driven by PtX production** in a closed system.

Sources: Energinet, Hourly production of offshore wind energy in DK2 in 2019 (link); Energinet, Capacity per municipality in DK2 in 2019 (link); Danish Government (2020), Climate Agreement (link); Ørsted, Project one-pager: Green Fuels for Denmark (link)

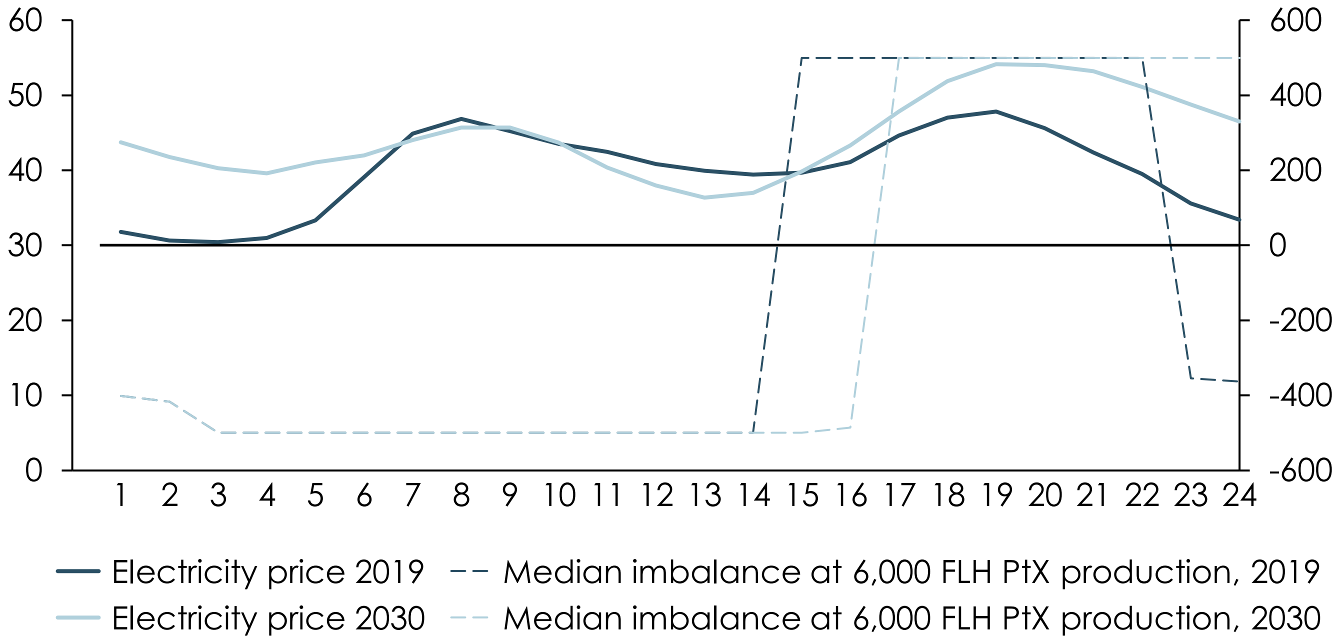
The wind power and PtX production entity feeds electricity into the open grid when prices are high and vice versa

Finally, we can zoom in on the **interaction between power prices and the outflow into and the inflow from the open grid.** It quickly becomes apparent, that the wind power and PtX production entity feeds electricity into the open grid when electricity prices are highest and draws electricity from the open grid when electricity prices are lowest.

The connection to the open grid at 500 MW is a restricting factor in all hours of the day, which means that the outflow into the open grid is in all hours limited to the capacity of the connection. The same holds true for the inflow from the open grid.

Electricity prices DK2 in 2019 and 2030, and the imbalance at 6,000 FLH PtX production

Left axis: EUR/MWh; right axis: MW



The left axis of this graph shows (forecasted) electricity prices for 2019 and 2030. The right axis shows the outflow (+500 MW) and inflow (mostly -500 MW), respectively. **Both flows are in almost all hours restricted by the connection to the open grid (500 MW).**

Outflow occurs in hours where prices are highest (2019: 15.00-22.00; 2030: 17.00-24.00), while **inflow occurs in hours where prices are lowest.**

Calculation of costs under capacity-based tariffs on page 19

Cost under current tariffs

Tariff component	Tariffs level	Consumption	Costs
Transmission grid tariff	6.58 EUR/MWh	1,680 GWh	11.1 mEUR
System tariff + balancing tariff	8.5 EUR/MWh	1,680 GWh	14.3 mEUR
Total			**25.4 mEUR**

Cost under proposed tariffs

Tariff component	Tariff level	Consumption	Costs
Transmission grid tariff	6.58 EUR/MWh	1,680 GWh	11.1 mEUR
System tariff	5.78 EUR/MWh	100 GWh	0.6 mEUR
System tariff above 100 GWh annual consumption	0.58 EUR/MWh	1,580 GWh	0.9 mEUR
Subscription	24 EUR/year	-	24 EUR
Total			**12.6 mEUR**

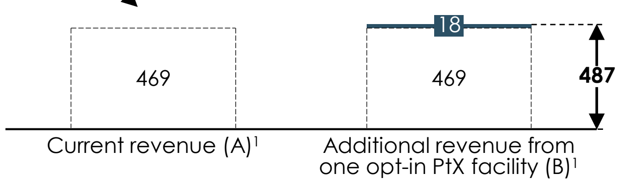
Cost under capacity-based tariffs

Capacity-based TSO tariffs		Maximum additional capacity demand beyond maximum grid capacity in DK2		Resulting costs
14.80 or 10.40 EUR/kW/year	×	370 MW	=	**5.5** or **3.8 mEUR**

Calculation of TSO revenue in short and long run on page 23

Energinet revenue from transmission grid and system tariff, see page 21[1]

Cost for hydrogen production of 6 GW in co-location.
Upscaled from the calculation example with the 1.3 GW hydrogen producer generating 3.8 mEUR additional revenue to the TSO, see page 20[2].
3.8 mEUR x (6 GW / 1.3 GW) = 17.54 mEUR



1) Energinet (2021) Konsekvensanalyse af mulighed for direkte linjer på transmissionsnettet / 2) Calculations by Copenhagen Economics

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