Copenhagen Economics

A MARKET DESIGN FIT FOR PURPOSE

HOW TO MAXIMISE THE VALUE OF THE NORTH SEA'S WIND RESOURCES

Deep dive (Product B)

CIP Foundation

03-05-2023

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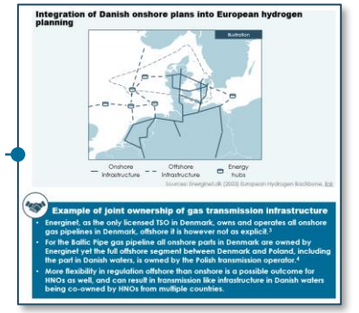
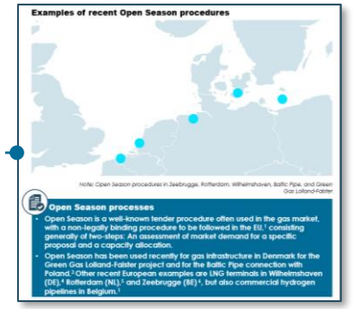
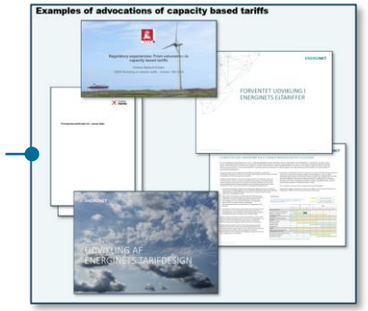
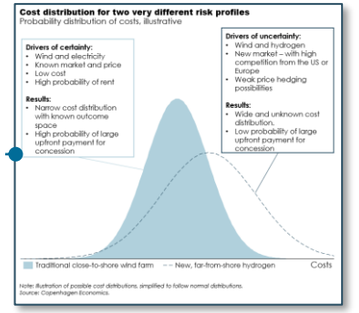








1. Clarify mandate of hydrogen network operator and ensure integration into a common European offshore hydrogen grid

Careful delineation of role of offshore hydrogen network operator (HNO) for green hydrogen

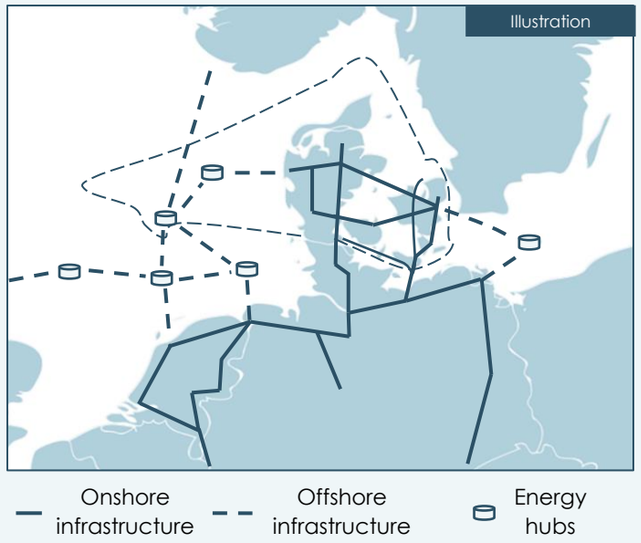
The mandate and framework for ownership of Danish offshore hydrogen infrastructure remains to be established. With the New Gas Act from January 2023, Energinet (and Evida) was allowed to plan, own and operate onshore hydrogen infrastructure. The onshore role of Energinet as the HNO, was further strengthened by the Letter of Intent to build an onshore hydrogen transmission interconnection between Denmark and Germany, which was signed on the 24 March 2023.[1] However**, no mandate to plan, build, operate or collaborate on offshore hydrogen transmission infrastructure has been granted to Energinet, nor any other Danish entity.** Furthermore, it is not yet decided whether and which infrastructure can or will be publicly owned.

It is highly likely that far-from-shore hydrogen hubs can economically be directly connected to the main hydrogen markets in Germany or the Netherlands, despite the seabed being Danish. To be viable, such interconnections will need to share many features with traditional TSO type infrastructure for international transmission with regulated third-party access and a transparent, cost-reflective tariff system. One approach to increase societal value in far-from-shore hydrogen projects could be to use fully commercial pipelines to connect production sites to publicly owned interconnector-type transmission pipelines. Another option is to have fully commercial infrastructure, which seems to be the preferred option for CCS, where the winning of the current public CCUS tender will be responsible for the entire value chain, *including* transportation infrastructure.[2]

Integrate with existing plans

With a clear mandate, Denmark can get up to speed with other North Sea countries and integrate with existing off-shore planning for hydrogen pipelines. It is in Denmark's interest to make sure that future hydrogen production from the Danish part of the North Sea can reach markets in Europe. Countries like Germany, Belgium, and the Netherlands are planning an integrated offshore hydrogen infrastructure. In the Netherlands, the gas TSO, Gasunie, has been given the role as Hydrogen Network Operator and been tasked to develop a hydrogen grid, onshore and offshore.[3] Integration into such existing and ongoing planning of offshore hydrogen will leave Danish market participants with a better foundation for developing their business cases and may help speed up development. Joint planning and ownership between gas TSOs/HNOs may also reduce risk from a national TSO/HNO point of view. Examples of joint ownership of gas transmission infrastructure already exist.

Integration of Danish onshore plans into European hydrogen planning



Sources: Energinet.dk (2023) European Hydrogen Backbone, link

Example of joint ownership of gas transmission infrastructure

- Energinet is the only licensed TSO in Denmark and owns and operates all onshore gas pipelines. However, the Baltic Pipe project shows a less strict approach for offshore pipelines.[4]
- Energinet owns the onshore components in Denmark, as well as the offshore components in the North Sea and the Little Belt. The offshore segment between Denmark and Poland is owned by the Polish gas transmission operator.[5]
- Additionally, a compressor station on Zealand, owned by Energinet, was co-financed by the Polish operator.[6]

Sources: 1) Danish Ministry of Climate, Energy and Utilities (2023) *Samarbejdsaftale skal bane vej for brintrørledning mellem Danmark og Tyskland*, link /// 2) Danish Energy Agency (2023) *CCS contract notice*, link /// 3) Gasunie (2023) *Gasunie's Hydrogen Ambitions on the North Sea* /// 4) Retsinformation.dk (2020) *Bekendtgørelse af lov om Energinet*, link /// 5) Baltic-pipe.eu (2023) *The Baltic Pipe Project Partners*, link /// 6) Baltic-pipe.eu (2023) *Compressor station in Denmark*, link

2. Clarify allocation mechanisms and practices of authorities

Three key focus areas can simplify processes and practices of authorities

We have identified that unclear processes is a barrier to developing the North Sea at the necessary pace. We identify three actions that can help clarify and speed up the process:

First, it should be absolutely clear from an up-to-date Danish Sea plan which areas of seabed are allocated for commercial, green hydrogen, energy islands or platforms etc., so that it is reasonable for stakeholders to assume that a project falling within a predefined scope would be viable in the given area.[1]

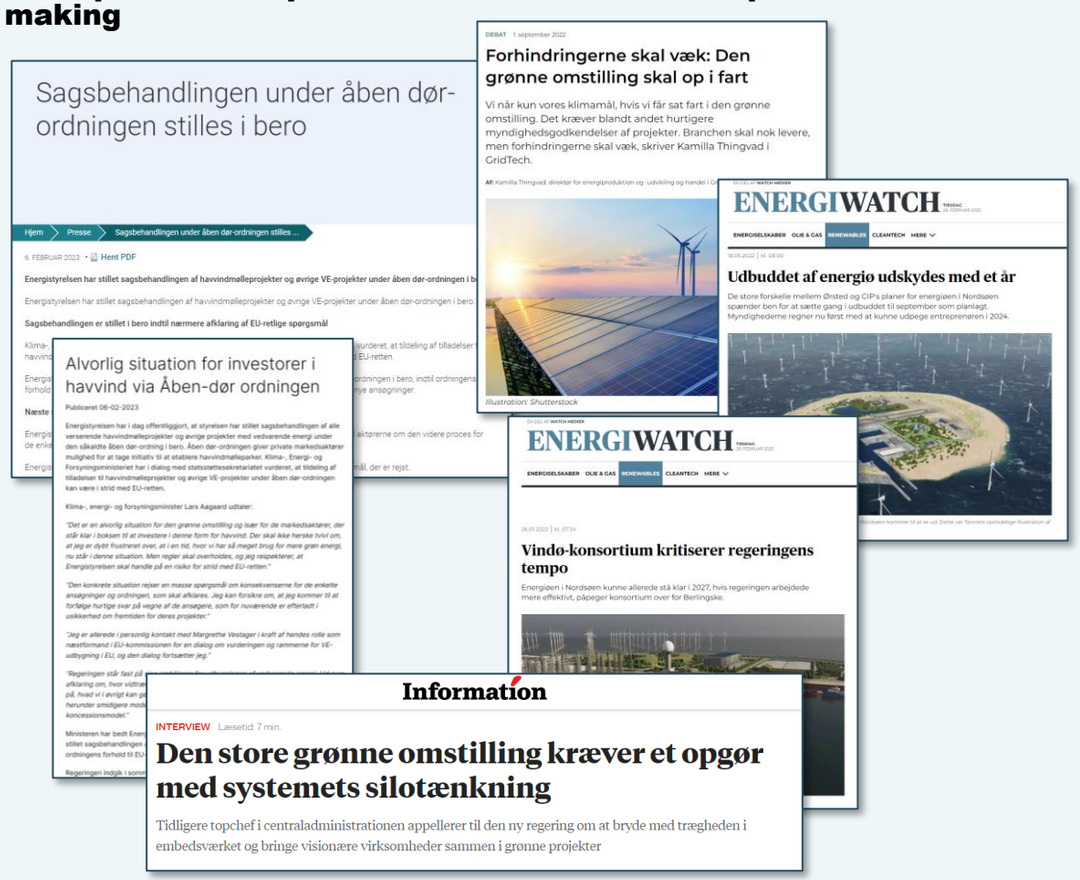
Second, the process by which seabed will be allocated going forward should be clear. For example, what are the opportunities for a more market led approach? Will allocations be given based on requirements on production of e.g. electricity, hydrogen or solely by highest bid? What will happen to the open-door scheme which was recently paused due to potential state aid issues? By the same token, it should be clearly communicated by which cadence state led public tenders can be expected to come out. In either approach, as much detailed design and capacity planning as possible should be left to the market/developers to decide.[2]

Third, clarify and speed up authorities' decision-making processes. The green transition and adoption of new technologies at a high pace are associated with high and fundamental uncertainty. When dealing with uncertainty it is a natural reaction to slow down, look for more information, analyse and postpone decision making. However, there are also significant costs associated with not making decisions, as it can deter and delay investments. Denmark may even lose a potential first mover advantage in green hydrogen production.

To help speed up decision making it could be useful to:

1. Allow authorities to take on larger upfront *regulatory risk*, i.e., the risk that the market design or regulation may not be perfect from the outset.[3] As the *financial risk* will mostly be carried by developers, the overall risk to the State may in fact not be very large.
2. Assign annual targets to allow new, offshore capacity instalments in the North Sea to relevant authorities to incentivise efficient case handling and create ownership for the trajectory.

Examples of critique of inconsistent and slow public decision making



Sources: Green Power Denmark (2022) *Forhindringerne skal væk: Den grønne omstilling skal op I fart*, link /// Klima-, Energi- og Forsyningsministeriet (2023) *Alvorlig situation for investorer I havvind via Åben-dør ordningen*, link /// Energistyrelsen (2023) *Sagsbehandlingen under åben dør-ordningen stilles I bero*, link /// Energiwatch (2022) Udbuddet af energiø udskydes med et år, link /// Energiwatch (2022) *Vindø-konsortium kritiserer regeringens tempo*, link /// Information (2019) *Den store grønne omstilling kræver et opgør med systemets silotænkning*, link

Sources: Interviews with stakeholders /// 1) CLEAN (2019) *Samfundsinnovation – Hvidbog om klyngeorganisationers rolle i den grønne omstilling*, link /// 2) Axcelfuture (2022) *Hvordan udbyder Danmark bedst havvind?*, link /// 3) Horten (2023) *Ny regulering af brint og et pilotprojekt til CO2 lagring trådt i kraft*, link

3. Use ‘Open Season-type processes’ to de-risk North Sea far-from-shore hydrogen infrastructure investments

Engage the market in a ‘committal’ dialogue to de-risk and scale future hydrogen infrastructure

The necessary interconnecting infrastructure investments are not without risks. When commissioning a pipeline for transport of a commodity that is not yet produced to a market that does not yet exist, there is an inherent risk of building a pipeline that is either too big, too small, suddenly unwanted, etc. As such it is clear, that it is not reasonable for a HNO, or any other investor for that matter, to invest without knowing the future demand for the infrastructure.

However, developers will find it difficult to develop their projects to a level of sophistication where they can express a firm, future demand without a fairly high degree of certainty of future plans for future pipeline infrastructure as well as tariffs, third party access etc. It is indeed a chicken-and-egg issue.

Using Open Season-type processes or structured, committal dialogues will allow for communication between the two sides, ensuring both that infrastructure is built, that it is dimensioned to meet a future, long term demand, and that this demand will materialise upon completion. As green hydrogen is an immature market, both HNOs and potential shippers expressing interest for a particular piece of future pipeline infrastructure are basing their positions on their individual expectations for a future hydrogen market.

Open Season processes are well known in development of gas infrastructure (pipelines, terminals) but have also been used for hydrogen infrastructure, see box on the right. One example of an European HNO who has embraced the Open Season model for hydrogen is Belgian Fluxys, who has already run a number of processes for selected hydrogen point-to-point pipelines around Antwerp, Ghent, Liège, etc.[1]

An Open Season-type process cannot necessarily stand alone, due to the infancy of the market and the number of market players. To ensure sufficient capacity in the medium to longer term, it may well be necessary to dimension and build bigger than what current or short-term forward-looking demand would suggest. This may make a case for the state and the HNO to take on upfront risk on a future proof design. The upfront risk is, however, expected to be limited in scale for two reasons; Firstly, the size of a pipeline may actually be limited since it will only need to connect to an infrastructure being planned and built by neighbouring countries. Secondly, the state is only taking risk corresponding to the share of future capacity that is above the demand of present-day users (as identified by an Open Season process.)

Examples of recent Open Season procedures

Note: Open Season procedures in Zeebrugge, Rotterdam, Wilhelmshaven, Baltic Pipe, and Green Gas Lolland-Falster

Open Season processes

- Open Season is a well-known tender procedure often used in the gas market, with a non-legally binding procedure to be followed in the EU[2], consisting generally of two-steps: An assessment of market demand for a specific proposal and a capacity allocation.
- Open Season has been used recently for gas infrastructure in Denmark for the Green Gas Lolland-Falster project and for the Baltic Pipe connection with Poland.[3] Other recent European examples are LNG terminals in Wilhelmshaven (DE)[4], Rotterdam (NL)[5], and Zeebrugge (BE)[6], but also commercial hydrogen pipelines in Belgium.[1]

Sources: 1) Fluxys (2023), link /// 2) ERCEG (2007) *ERCEG Guidelines for Good Practice on Open Season Procedures*, link /// 3) Energinet.dk (2023) *Grøn gas Lolland-Falster*, link /// 4) LNG Prime (2022), link /// 5) LNG Prime (2022), link /// 6) Fluxys (2020), link

4. Develop a long term oriented and cost-reflective tariff system

A forward looking cost-reflective tariff system enables efficient use of hydrogen grid infrastructure

The general aim of tariffs is to recover the costs of the monopolistic operator while promoting efficiency.[1] Generally, there are two types of tariffs: volumetric- and capacity based. It is broadly accepted that the cost-reflective capacity based tariffs incentivise an efficient use of a network, leading to the lowest cost associated with developing and operating the grid.[2]

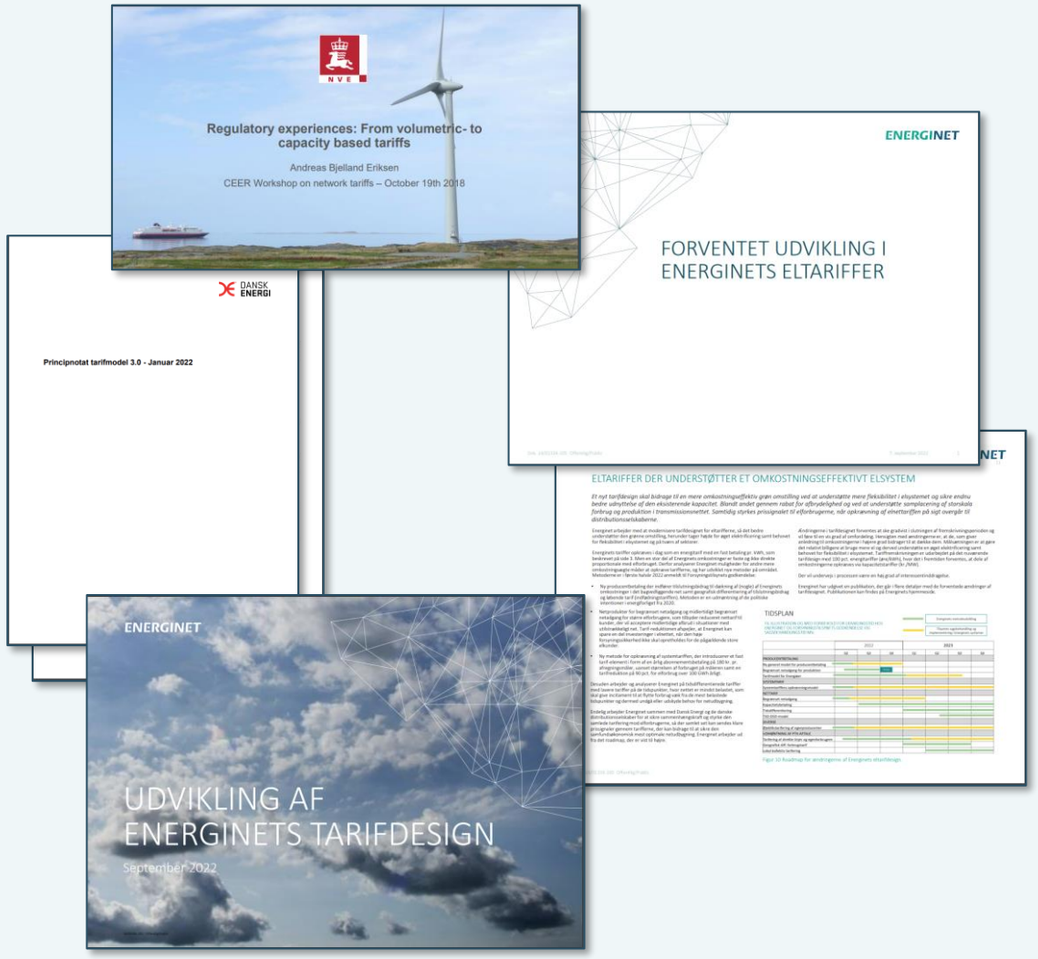
Historically, a volumetric tariff framework in Denmark has echoed the fact that most of consumption originates from households and smaller businesses with somewhat uniform consumption patterns, leading to little focus on how tariffs affect the use of capacity in the grid. Now, with electrification, a trend towards more capacity based tariffs has begun in both Denmark as well as in neighbouring countries, see examples to the right.[3]

For a new hydrogen grid, the optimal tariff design will be capacity based tariffs, where users of the network will pay tariffs reflecting the capacity that their use gives rise to. However, it is important to note a key difference between the electricity and an upcoming market for green hydrogen. Whereas the costs of the electricity infrastructure can be shared by a very large number of users, the hydrogen grid will only be used by a few, large users. This initial user base with be unable to pay tariffs to fully cost recover a new grid, which is rightfully dimensioned for a much larger future demand.

Thus, **phasing-in a hydrogen grid by applying a long term view will be necessary**, ensuring that tariffs initially are put at a level that allows for a sustainable future use of the grid. This could be done by having initially lower tariffs, such that the initial users (first movers) do not have to cover the full costs, allowing for entrance of more grid users (second movers).

To avoid concerns as to compatibility of *phase-in* hydrogen tariffs with State Aid guidelines we would suggest a pan-European tariff methodology to be developed, potentially sponsored by ACER (European cooperation of energy regulators), and approved by the EU Commission and appropriate national regulators well in advance of opening for transmission services for green hydrogen. By the same token, tariffs for interconnectors, onshore/offshore or even public/private interfaces should be developed, carefully assessed and approved (if necessary) in advance to provide transparency and allow the market to plan and invest accordingly. Regulation and a directive is currently being developed in the EU.[4]

Examples of advocations of capacity based tariffs



Sources: Energinet (2022) *Forventet udvikling i Energinets tariffer*, link /// Dansk Energi (2022) *Principnotat tarifmodel 3.0*

Notes: Several other principles of tariff setting such as: non-distortionary, non-discriminatory, transparency and predictability also exist.

Sources: 1) Acer (2019) *Report on transmission tariff methodologies in Europe*, link /// 2) CEER (2017) *Electricity Distribution Network Tariffs - CEER Guidelines of Good Practice* /// 3) CEER (2018) *Regulatory experiences: From volumetric- to capacity based tariffs*, link /// 4) European Council (2023) *Press release: Gas market package: member states set their position on future gas and hydrogen market*, link..

5. Adopt risk-sharing models between developers and the state

Far-from-shore hydrogen projects have specific conditions that suggest the need for risk-sharing models to increase societal value

Far-from-shore hydrogen projects are riskier than close-to-shore wind farms which have a proven market for electricity and limited competition due to transport costs. Green hydrogen faces *technological risks* and *commercial risks* due to the underdeveloped market. The graph to the right illustrates how different factors create more uncertainty in the form of a different distribution of revenues and costs, which in total makes investing in far-from-shore hydrogen riskier for the investor: not only with a larger variation around an expected return level, but also uncertainty about the distribution and mean of returns.

Traditional concession models are likely to reduce government revenue for green hydrogen. The traditional concession model for offshore wind in Denmark involves state-led tenders/auctions where the most attractive offer wins. Close-to-shore wind farms have a narrow and known risk profile, resulting in predictable upfront payments from private companies. In case of a far-from-shore *hydrogen* project, the risk profile is much wider and unknown, leading to large uncertainty about possible real value of the seabed, thus decreasing bids in the auction. In other words, the actual bids are likely to be *below* the expected average value of the seabed. This suggests the adoption of a risk-sharing model for far-from-shore hybrid (electricity + hydrogen) and hydrogen projects.[1]

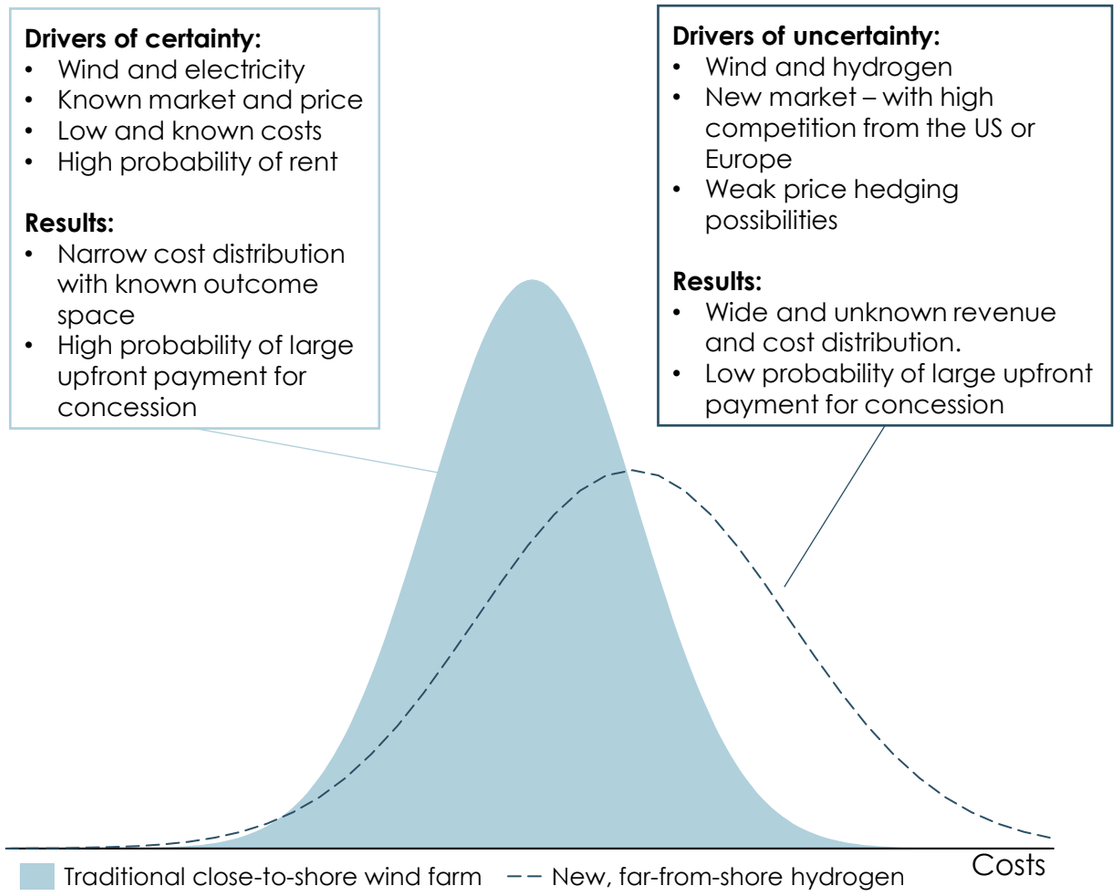
A design could take inspiration from Danish oil and gas exploitation in the North Sea. For all Danish oil and gas licenses, Nordsøfonden has mandated ownership. This implies sharing of risks and profits in proportion to the ownership share. The active ownership also provides transparency for the state as to profits, losses, and various commercial decisions of the license holders. For green hydrogen, a concession could combine a relatively low concession payment in the exploration and development phase with profit-sharing as actual production commence. Such an approach ensures that only serious bidders with the financial and technical capacity to deliver will bid, while also increasing expected public revenues.

Payoffs of new, far-from-shore hydrogen concession types[2]

	Risk-Sharing	Payment type	Potential payment to the state
1. Upfront	None	Lump sum	Low
2. Profit-sharing	Yes	Continuous in production phase	High

Cost distribution for two very different risk profiles

Probability distribution of costs, illustrative



Note: Illustration of possible cost distributions, simplified to follow normal distributions.
Source: Copenhagen Economics.

Sources: 1) Energistyrelsen (2021) *Modeller for tildeling af koncessioner for fremtidige havvindudbud* /// 2) Axcel Future (2022) *Hvordan udbyder Danmark bedst havvind?*, link

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