



# LookNorthH2

SIF Discovery – End of Phase Report

28th May 2024



# Report Outline

1. Executive Summary
2. Potential OEH location and configuration – WP2
3. Economic Appraisal – Cost Benefit Analysis – WP3
4. Regulatory, policy and market codes gaps – WP4
5. Appendix – WP1

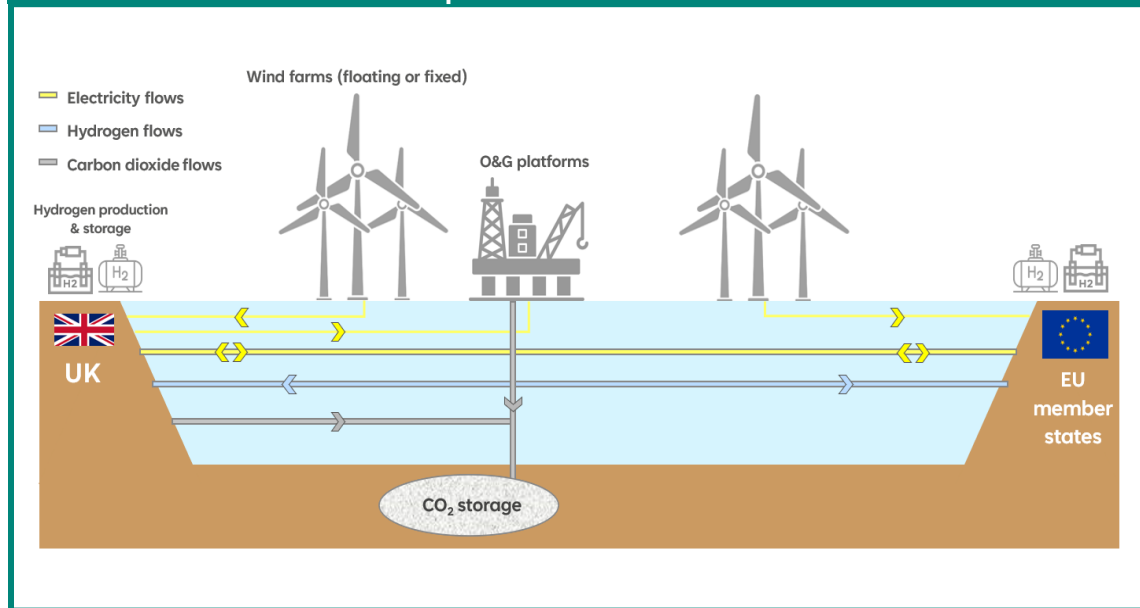
# 1. Executive Summary

# The LookNortH2 concept explores the repurposing of O&G infrastructure for hydrogen production and carbon capture

Optimising energy production is key to achieving the 2050 net zero target at the lowest cost for consumers. The UK is set to rely on offshore wind for most of its final power and energy use. A centralised offshore energy hub concept may be able to provide significant socio-economic and environmental benefits by integrating use cases.

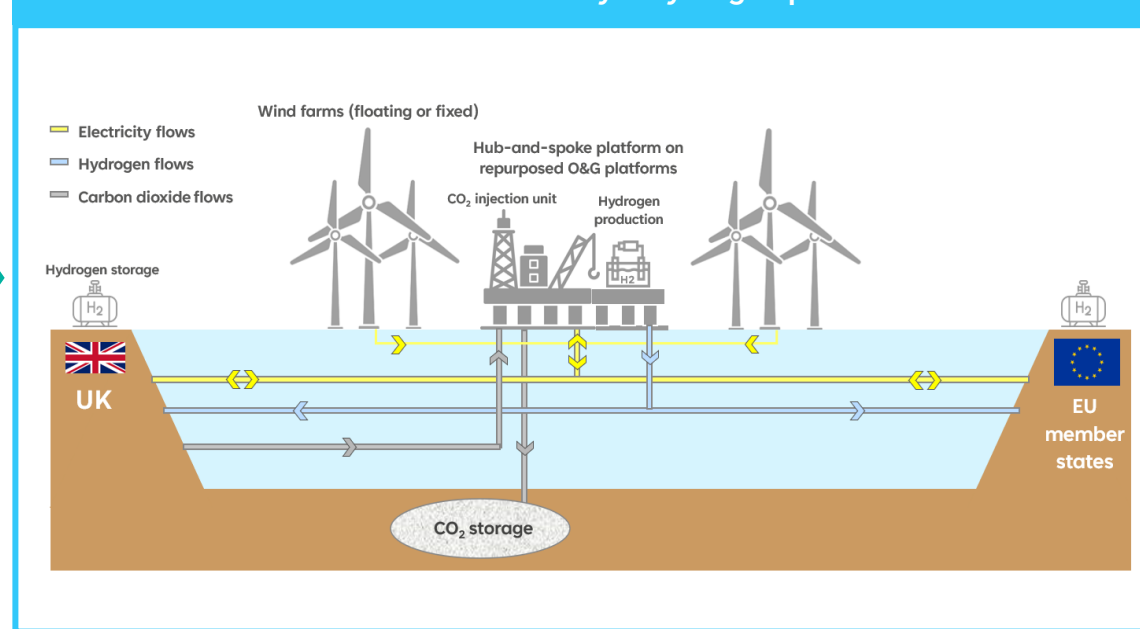
## Counterfactual

### BAU - Decentralised electricity production & electrolyser location for hydrogen production onshore



## Factual

### LookNortH2 - Centralised electricity & hydrogen production offshore



# Three potential zones for Offshore Energy Hubs have been identified based on ideal characteristics for their development

An ideal offshore energy hub location includes parameters listed below with their relative importance to the hub:

## Parameters



Relatively high annual mean wind potential



Shallow water depth



Existing oil & gas assets



CO<sub>2</sub> storage potential

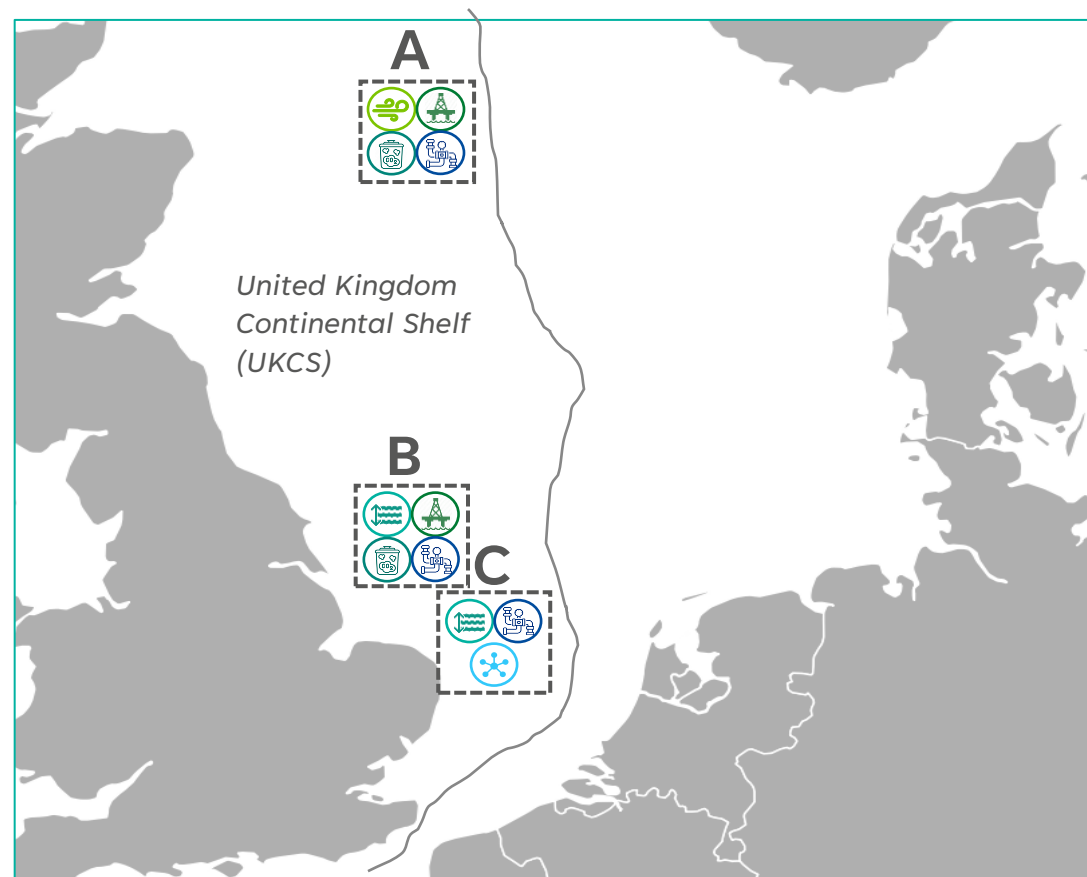


Existing energy transmission infrastructure



Connectivity with neighbouring countries

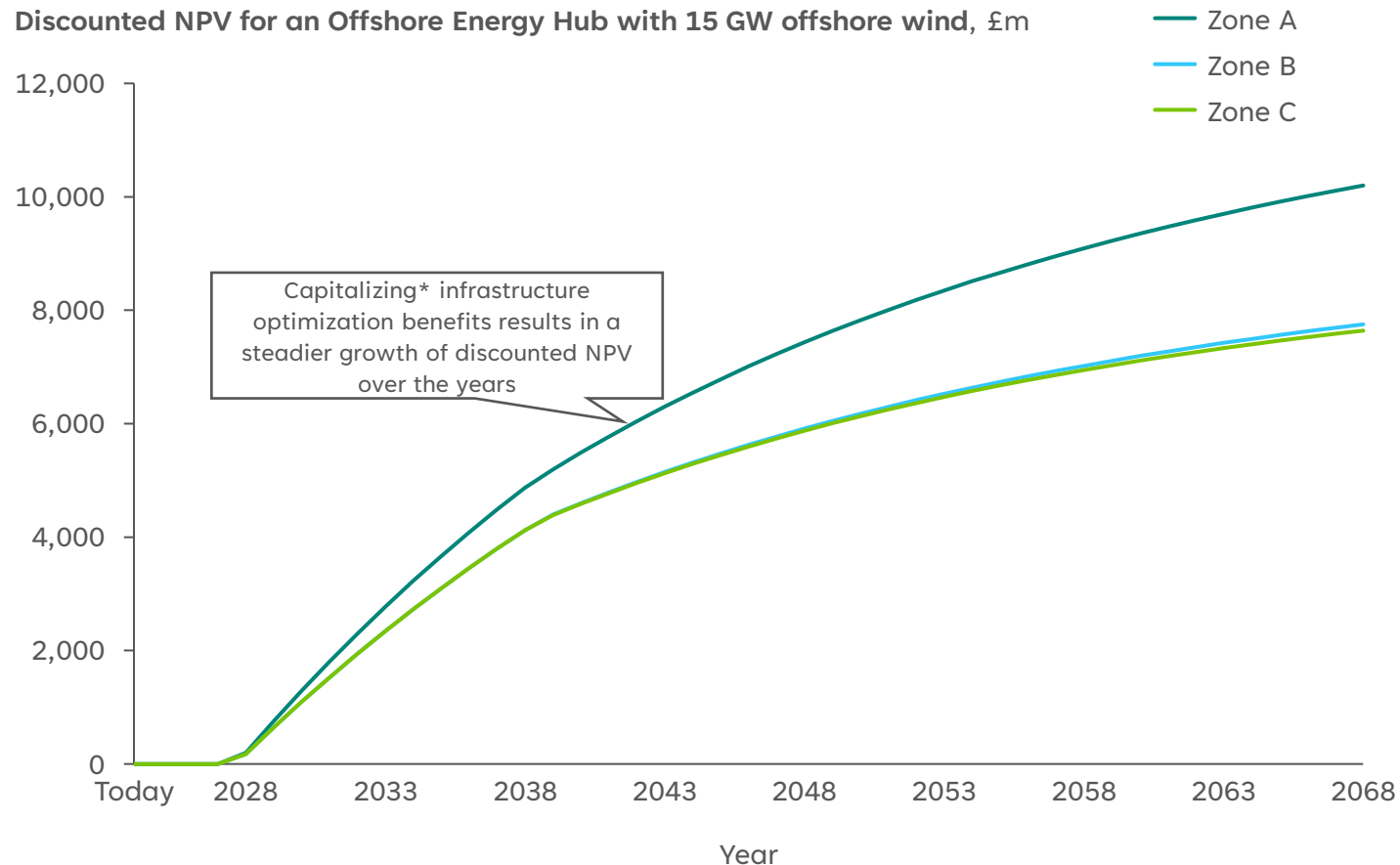
Three North Sea zones, represented below, have been identified as most suitable for the development of offshore energy hub:



\*High-level map – borders and hub locations have been simplified. For high-level overview of each location characteristics please refer to the Appendix.

# All hub configurations and zones report financial benefits, with most occurring when the hub is developed far from shore

## Cumulative discounted net financial benefits – 15 GW of connected offshore wind



Up to  
**£10,197m**

of cumulative discounted net financial benefit in the most optimal configuration (Zone A) by 2068

**2028**

is the year the first benefits are obtained through infrastructure optimisation

**>9MtCO<sub>2</sub>**  
of GHG emissions saved through the larger phase-out of natural gas in the system by 2068

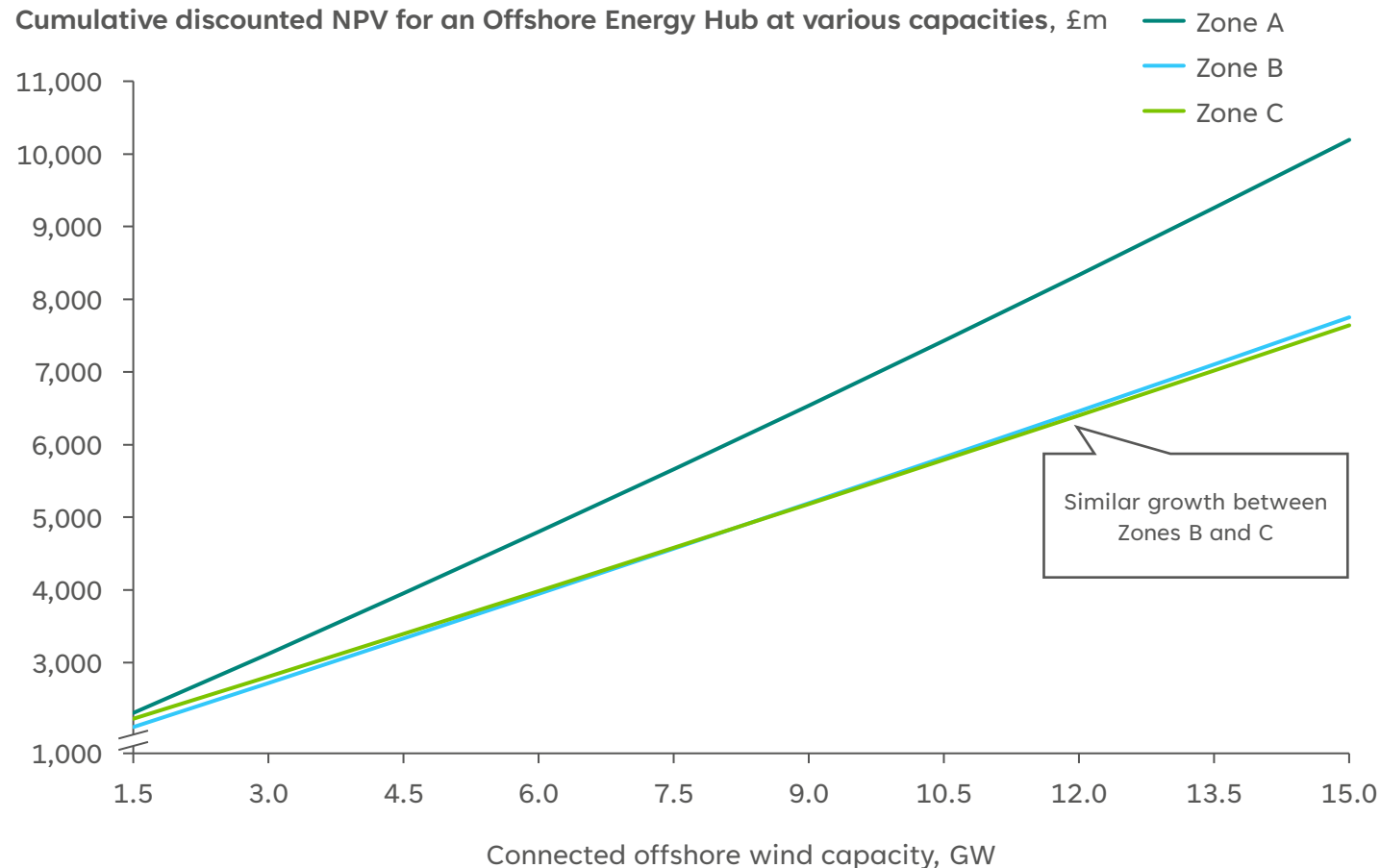
**3,740**  
jobs maintained /created

**£1.1bn**

of undiscounted costs associated with platform development

# Net financial benefits grow linearly with the magnitude of the offshore energy hub

## Cumulative discounted net financial benefits – various connected offshore wind capacities



**1.5 GW**

is the average  
installed capacity per  
1 connected offshore  
wind cluster

**>4x**

more benefits  
between 10x capacity  
change for optimal  
configuration (Zone A)

**15 GW**

Is the connected  
capacity at which  
the benefits are  
the highest

**Zone A**

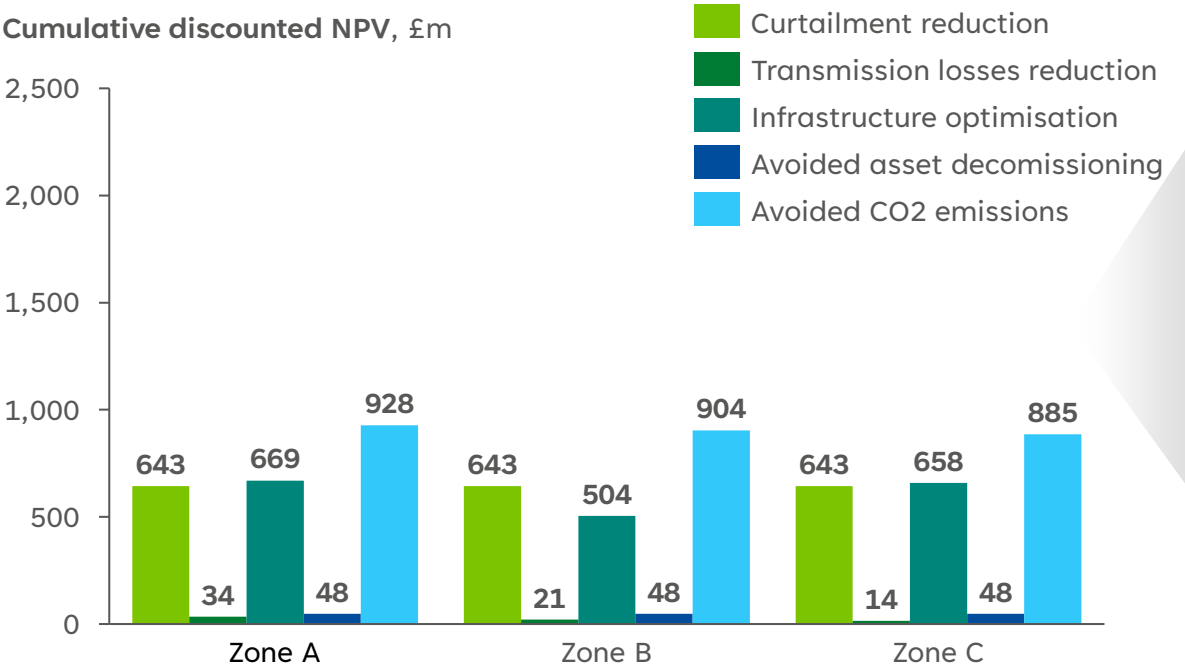
Shows the biggest  
growth but is not  
optimal at 1.5 GW  
connected capacity

# This linear growth in financial benefits is due to a significant reduction in infrastructure capital expenditure

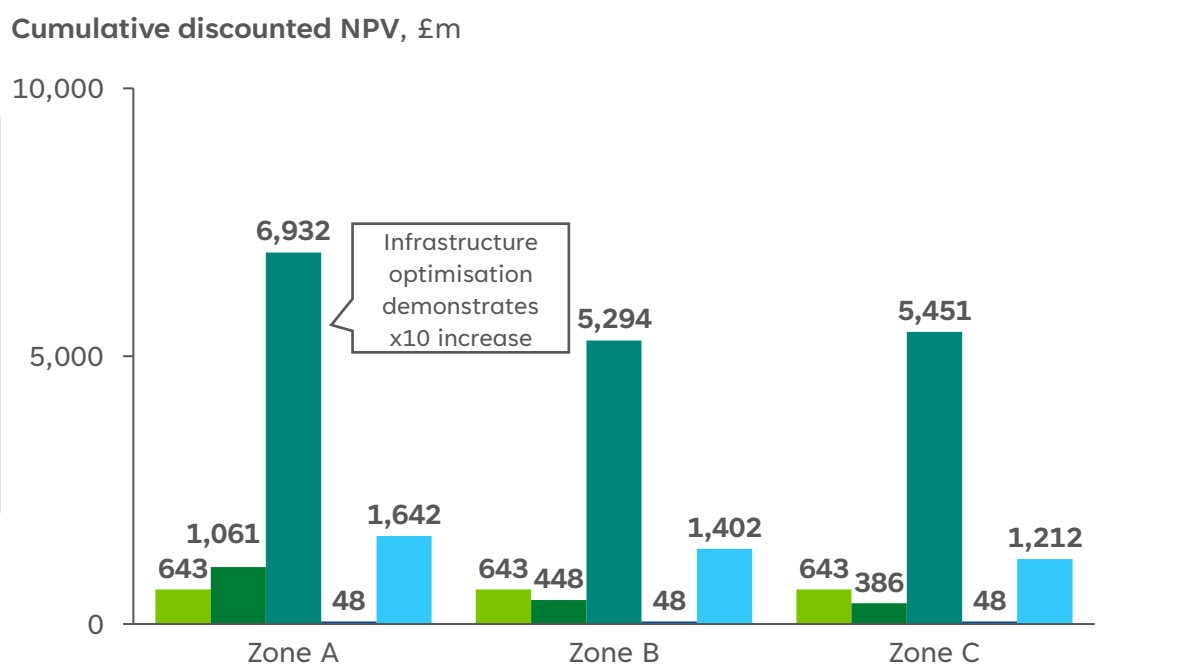
## Key takeaways

The linear growth of benefits is largely driven by infrastructure optimisation. At ‘Zone A’, if the offshore wind capacity is 1.5 GW, the benefits from infrastructure optimisation are £669m compared to £6,932m if the capacity is increased to 15 GW. This results in more than a 10x increase in benefits with a 10x increase in capacity. For other zones, infrastructure optimisation is also the main driver, but at a lower scale. This is due to ‘Zone A’ being further from the shore, maximising its benefits.

### 1.5 GW of connected offshore wind



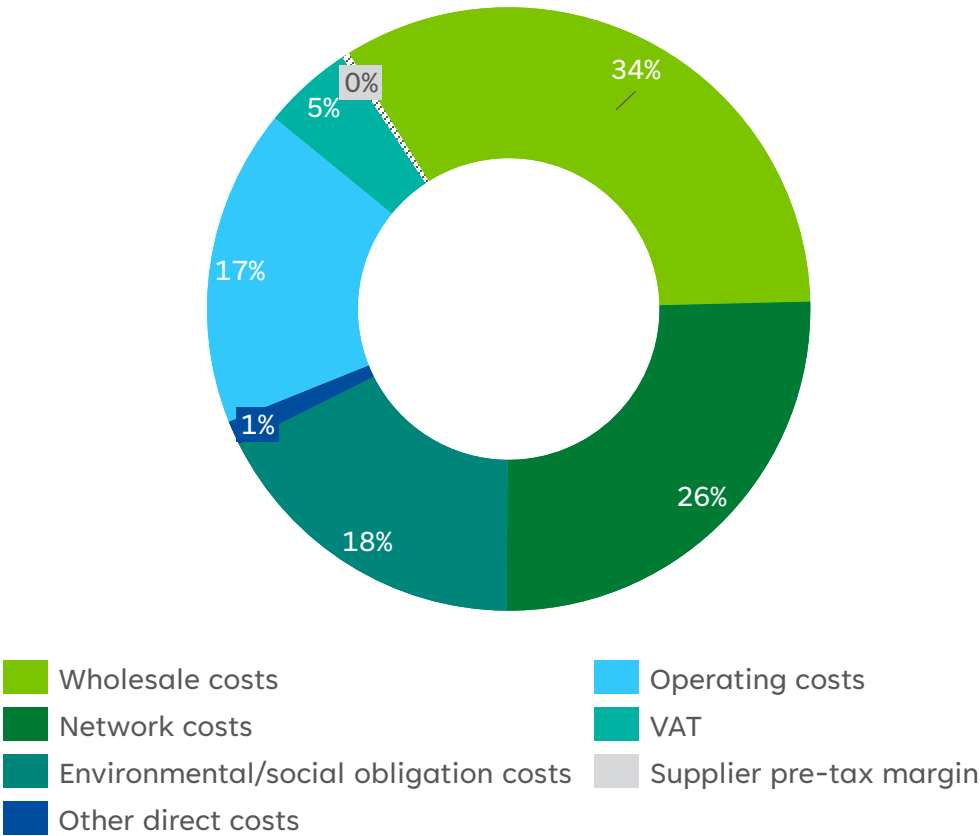
### 15 GW of connected offshore wind





# Benefits can result in significant energy bill savings for GB consumers under appropriate market mechanism

Breakdown of a typical GB consumer electricity bill



Consumer cost savings through Offshore Energy Hubs

Context

While more offshore wind will drive down **wholesale power prices**, if additional transmission infrastructure is needed to support it this can add **network costs** to consumer bills. Additionally, more renewables require higher **system operation management costs**, such as additional constraint payments, which are passed through to consumers. Finally, government incentives for renewables such as Contract for Difference are paid by energy consumers through **environmental or social obligation costs**.

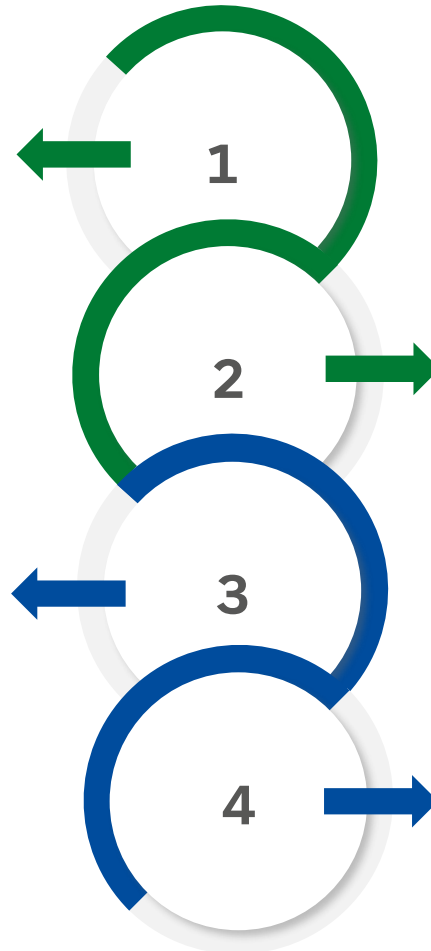
| Offshore energy hubs financial savings     | Impact on consumers bills |         |           |   |
|--|---------------------------|---------|-----------|---|
|  | Wholesale                 | Network | Operation | Obligation  |
| Curtailment reduction                      |                           |         | ⬇️        | All benefits result in stronger RES developer business cases which in turn reduce the incentives volume and price required to drive their development |
| Transmission losses reduction              | ⬇️                        |         |           |   |
| Infrastructure optimisation                | ⬇️                        | OR ⬇️   |           |   |
| Avoided CO <sub>2</sub> emission reduction | ⬇️                        |         |           |   |

**Note:** Power market are complex and specific benefits allocation will depend on the chosen market design.

# To realise these benefits, OEHs require more integrated regulations and decisive action on aspects of market design

**Regulatory gaps:** The key challenge faced by the development of OEH lies in the fragmentation of existing regulations. Siloed frameworks and processes across different sectors impede system integration projects.

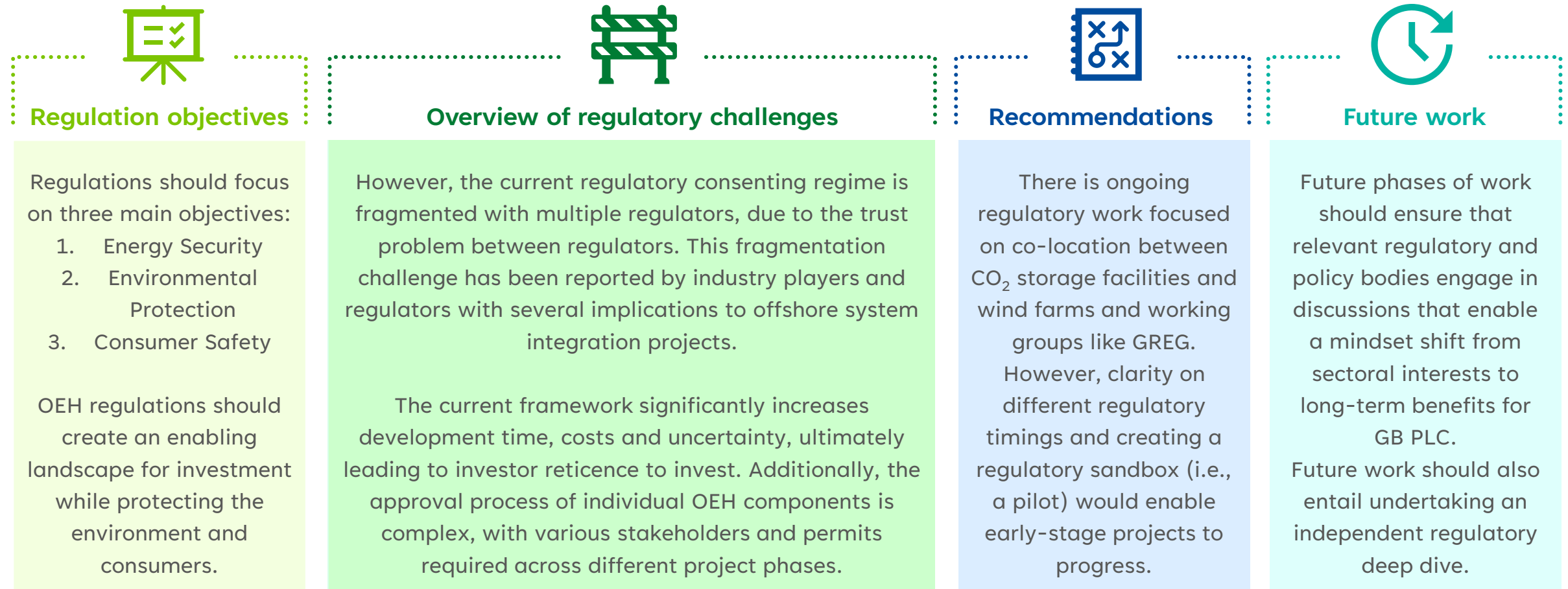
**Market Design:** The development of OEH creates new market interactions across different energy vectors (electricity, H<sub>2</sub>, CO<sub>2</sub>) which existing market design does not cover.



**Future work:** Although there is ongoing work from regulators and other working groups, greater clarity on approval timings and a sandbox approach to permitting is needed to help streamline the process for integrated projects.

**Future work:** Further work is required to align the critical aspects of OEHs including market arrangement, network governance, cross-border mechanism, operability and charging methodologies and contracts

# Although there are several moving pieces in OEH regulations, increased alignment would be key to ensuring its success



# To achieve market design objectives, the ESO, Ofgem, DESNZ and industry should make concrete decisions in multiple areas



## Market arrangements including home market or offshore bidding zone (OBZ) configuration

OBZ with implicit trading market arrangements is currently the preferred offshore market configuration but this could pose price and volume risks for the OSW farm. Work focused on cross-border subsidies and contracts is required to conclude whether this design is well suited when including offshore offtakers.



## Balancing and operability of Offshore Energy Hubs

OHA can provide extensive cost savings through ancillary services as expected. However, MPIs built in the South of the UK could increase network constraints costs across the network. Additionally, flexibility could also be provided by the offshore H<sub>2</sub> developer by fluctuating outputs based on demand signals.



## Interaction with European markets and European network planning

With a combined 2050 target of ~290GW and an initial offshore grid acknowledged by all North Sea TSOs, coordination with European markets is crucial. Agreeing on cost and benefit rules, linking trading schemes and setting up dedicated funds are required to realise this collaboration.



## Capacity, charging, metering and support schemes

UK interconnectors may need to be adapted to fit EU flow-based target capacity calculation methodology (CCM). Regarding support schemes, using the OBZ market price as the CfD reference price would prevent developer price risks. Finally, offshore H<sub>2</sub> production facilitates Guarantee of Origin (GO) certification as producers can be considered BTM. Additionally, the appropriate charging methodology for both MPIs and H<sub>2</sub> interconnectors must ensure that there is sufficient incentive for developers to develop offshore.



## Contractual arrangements including the Industry Codes and Standards to be applied.

Additions and changes to codes and contracts may be required to include new OEH interactions; such additions should facilitate synergy of the different energy vectors and international coordination.

## 2. Potential OEH location and configuration

Work Package 2

# Offshore Energy Hub Preferred Locations

# The following parameters were selected to assess each of the most applicable zones for offshore energy hub rollout

## Parameters



Relatively high annual mean wind potential



Shallow water depth



Existing oil & gas assets



CO<sub>2</sub> storage potential

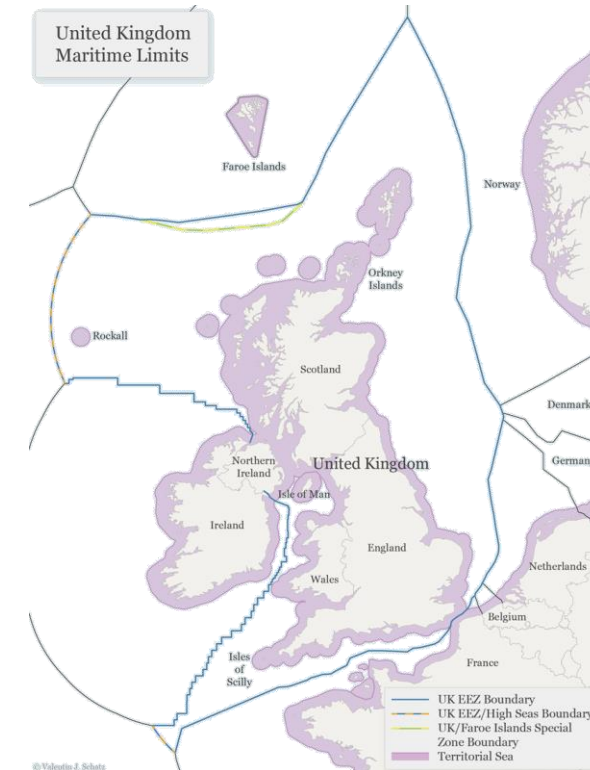


Existing energy transmission infrastructure



Connectivity with neighbouring countries

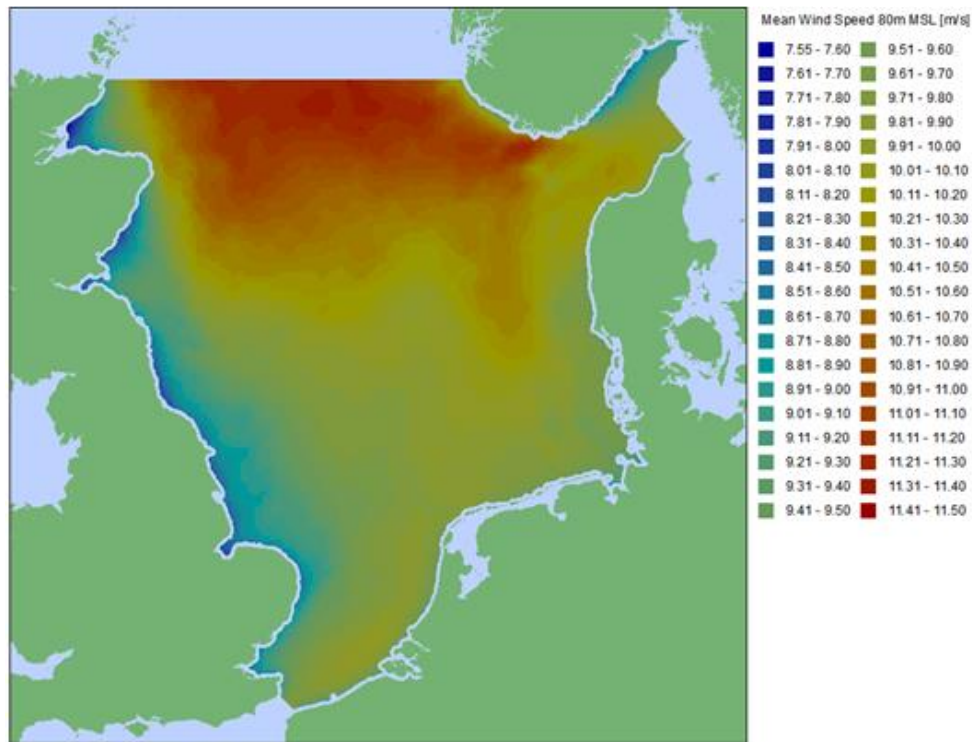
## Location scope - UKCS





# The mean wind speed potential is relatively high across the North Sea, increasing further towards the north

North Sea Wind Mean Wind Speed Potential



## Relevance



Higher Mean Wind Speed potential significantly increases the power outputs of a wind farm by the power of 3. As such, a higher average mean wind speed significantly improves the business case for offshore energy hubs. This is particularly true for large-scale hubs, which will require high-power outputs to compensate for their capital-intensive nature.

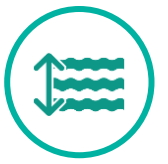
## Key Takeaways



- The highest wind potential is achieved off the coast Scotland in the north of the North Sea (wind speed average 11-12 m/s)
- There will be a trade-off between levels of CAPEX and revenue across the North Sea as the zones with higher potential also are the ones most complex to build, operate and maintain.

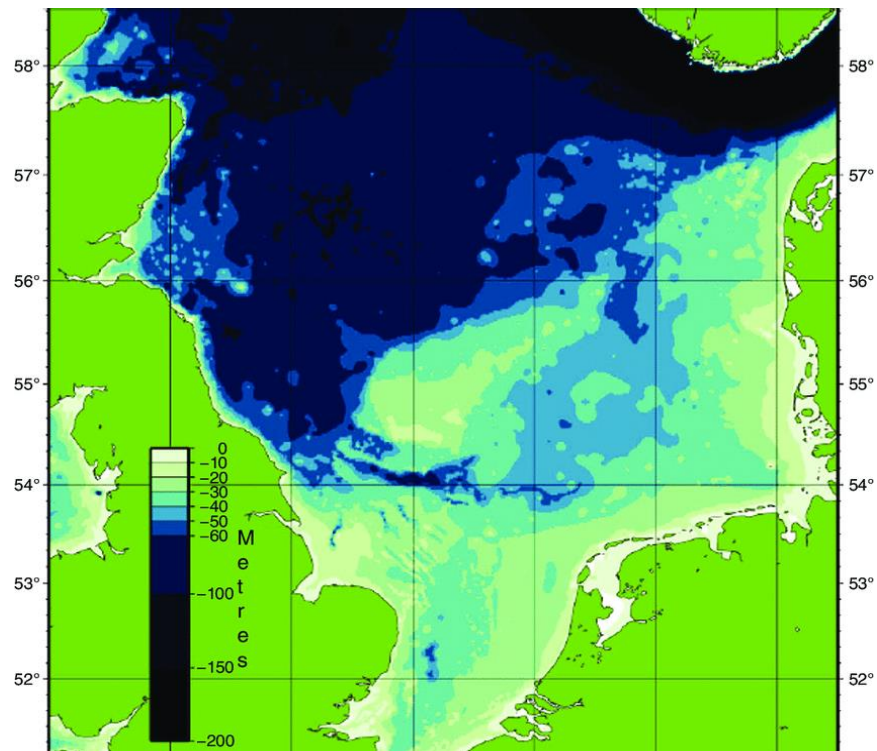
**What this means for zone selection:** Comparing offshore energy hubs development in the north of the North Sea against other regions closer to shore will be interesting to better understand trade-offs.





# Deep waters between Scotland and Norway are only suitable for floating offshore wind deployment

North Sea Water Depth



## Relevance



Shallow water significantly reduces the costs of offshore wind development by enabling fixed-bottom offshore wind farms and platforms. It is commonly believed that for depths above 50 meters, floating offshore wind becomes a more economically viable option, with a theoretical depth limit of 1000 meters.

## Key Takeaways



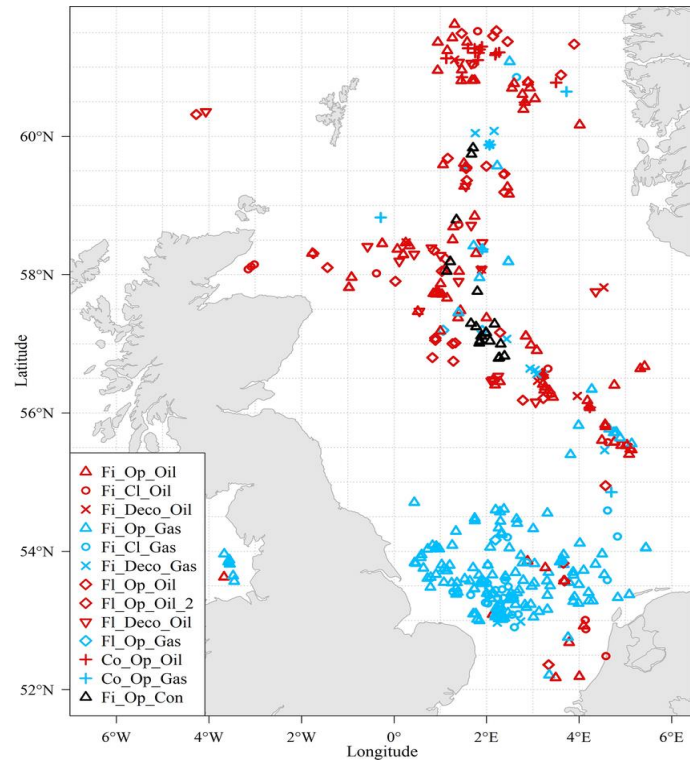
- Most of the water in the north of the North Sea is deeper than 50 meters which would force the development of floating substructure.
- Most of the water between England and Continental Europe is shallower than 50 meters. Additionally, the Dogger Bank provides particularly shallow water, ideal for the development of fixed-bottom offshore wind.

**What this means for zone selection:** Water depths are roughly inversely proportional to annual mean wind speeds. Zones between England and Netherlands/Belgium are in shallow waters and, therefore are suitable for fixed offshore wind.



# Majority of oil platforms are located between Scotland and Norway, gas platforms are east off England's coast

## Existing North Sea Oil & Gas Platforms



## Relevance



Repurposing existing O&G infrastructure can significantly reduce the costs and timelines for developing offshore energy hubs. Additionally, it can help reduce the financial (and environmental) burden of decommissioning assets. It should be noted that any offshore energy hub is likely to require some new build infrastructure as the platform cannot be used for large-scale hydrogen production. The current design of O&G platform is optimised for O&G extraction and remains relatively small or not adapted to other uses. Oil platform are generally slightly larger than gas platform.

## Key Takeaways



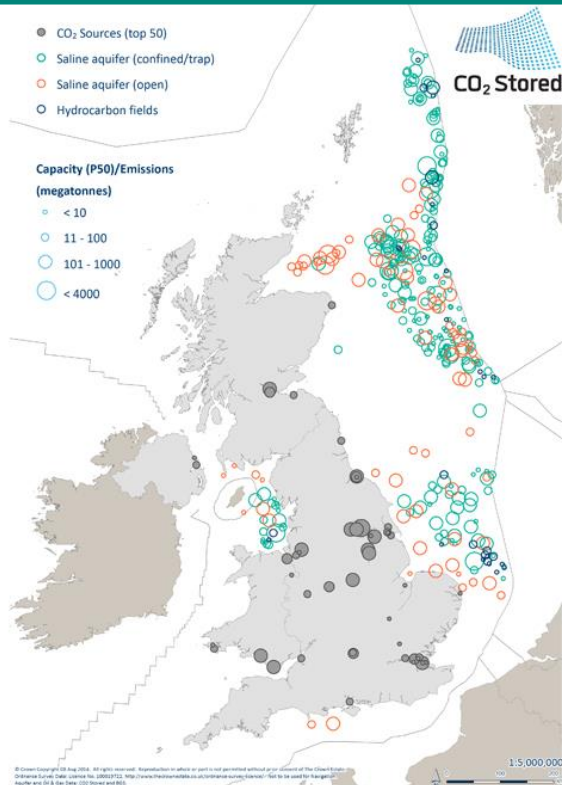
- Most of the North Sea oil infrastructure is located in the north of the North Sea.
- The zone between England and Continental Europe is largely made up of gas platforms

**What this means for zone selection:** Both the north of the North Sea and off the coast of Teesside and Bacton are ideal location for the development of offshore energy hubs.



# Both hydrocarbon field and saline aquifers in the North of the North Sea can provide the highest CO<sub>2</sub> storage capacity

## Potential CO<sub>2</sub> storage capacity in the UKCS



## Relevance



Developing offshore CO<sub>2</sub> storage significantly improves the business case for offshore energy hubs and can be co-located next to existing O&G platforms once the fields are depleted. A larger storage capacity can be achieved through the exploration of deep saline aquifers – geological formations of porous sedimentary containing salt water. These aquifers are located mainly in the hydrocarbon provinces.

## Key Takeaways



- The north of the North Sea has the largest potential for CO<sub>2</sub> storage, due to a large number of saline aquifers, as well as multiple oil/gas fields.
- There are several smaller saline aquifers located off the east coast of England. The regional CO<sub>2</sub> storage capacity in the UKCS approximately matches the location of O&G exploitation.

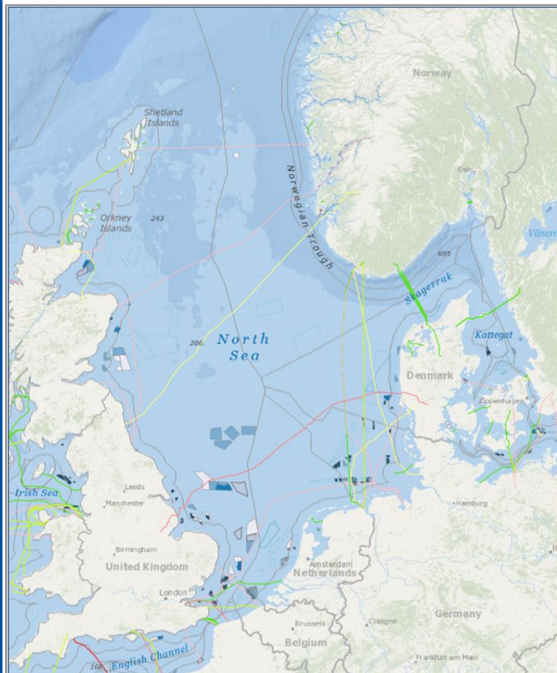
**What this means for zone selection:** There are good synergies between zones with existing O&G infrastructure and zones with CO<sub>2</sub> storage capacity (as expected).



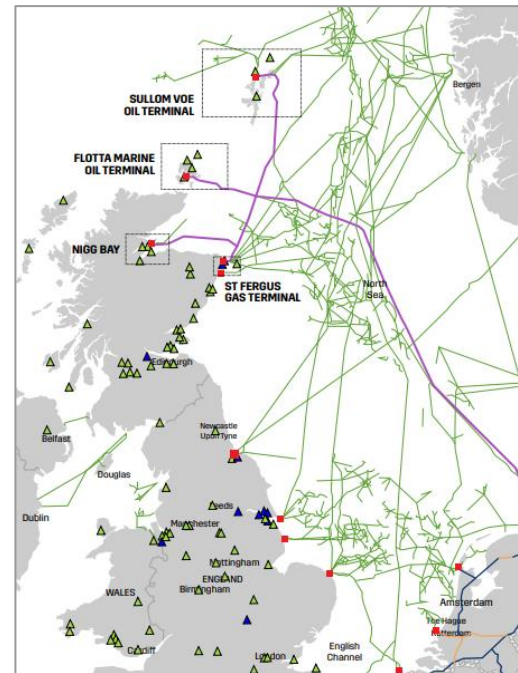
# Leveraging of existing and planned infrastructure between UK and Europe would maximise Look North H2 potential

## North Sea Energy Transmission Infrastructure

Map of electricity interconnectors<sup>1</sup>



Map of gas pipeline infrastructure<sup>2</sup>



Proposed hydrogen pipelines

## Relevance



The repurposing and further use of existing infrastructure would help to optimise the required investments into new electricity and hydrogen infrastructure. Proposed/in-construction hydrogen pipelines are also of direct consideration for hub's co-location as this would significantly reduce the need for additional investments.

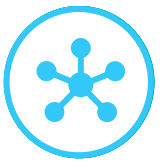
## Key Takeaways



- The north of the North Sea has the most existing oil and gas infrastructure.
- The Hydrogen Backbone Link is a plan to transport hydrogen from the north of Scotland to Continental Europe through the North of the UKCS leveraging existing pipeline.
- There are also operational and planned electricity interconnectors between Scotland and Norway.
- Other zones located between England and continental Europe also have existing electricity and gas infrastructure that can be repurposed.

**What this means for zone selection:** Legacy O&G-intensive production zones logically also have existing oil & gas transmission infrastructure nearby. It should be noted that not all offshore O&G pipelines are of the same size, not all of them might be suitable for large-scale hydrogen repurposing. Further analysis should be conducted to determine exactly which pipelines could be repurposed.

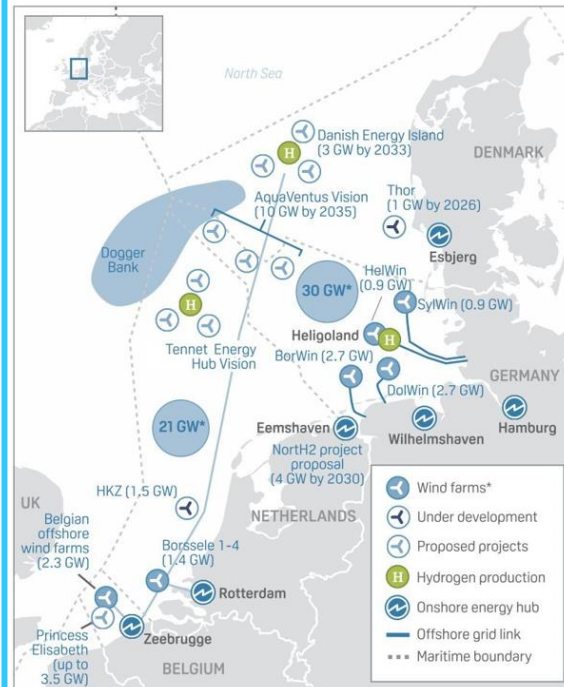




# Coordination with EU's offshore hub developments can lower infrastructure costs and provide clarity on pricing

## EU countries' North Sea energy development strategy

### Offshore energy general development<sup>1</sup>



### Initial offshore grid plans<sup>2</sup>



## Relevance



Coordination with EU's offshore hub developments would enable great market liquidity and flexibility. Connecting UK and European offshore energy hubs together can also help reduce total North Sea infrastructure costs. This connected network of offshore energy hub would also create larger bidding zones, thus consolidating offshore bidding zone price formation (if implemented)

## Key Takeaways



- The majority of the EU's offshore hub development occurs off the coast of The Netherlands, Germany, and Denmark, with initial offshore grid plans to connect these hubs.

**What this means for zone selection:** Zones off England's east coast are next to the EU's offshore energy hubs and therefore can leverage them to provide infrastructure and pricing benefits to a wider group of beneficiaries

# Every zone has its own benefits and challenges, driven by selected parameters and its importance

| Zone | General   |
|------|---|
| A    | <p><b>Benefits:</b> The area in question is an excellent location for maximizing power generation. It benefits from high potential wind speeds, the most number of oil platforms, and the largest potential for CO2 storage. Additionally, there is already existing infrastructure for electricity and gas that can be repurposed. Furthermore, there are plans for a hydrogen pipeline that would connect Scotland and continental Europe, providing additional benefits for the area.</p> <p><b>Challenges:</b> The downside of the zone is its deep waters and long distance from the shore, most likely resulting in higher capital and operational expenditure.</p>   |
| B    | <p><b>Benefits:</b> The zone which hosts the majority of the UK's offshore wind production is currently the preferred zone for this industry. This location is preferred due to its shallow waters, which is also beneficial for the offshore hub concept. There are various advantageous factors for the hub's development, such as the presence of numerous gas platforms, the potential for CO2 storage, and the proximity of existing electricity and gas connections. This zone is also located near existing offshore gas storage facilities (e.g., Rough storage operated by Centrica) that potentially could be repurposed to hydrogen at a later date.</p> <p><b>Challenges:</b> This zone does not have many downsides for offshore development but could be potentially constrained by space in the long term.</p> |
| C    | <p><b>Benefits:</b> This zone offers several advantages, including its proximity to the EU's offshore hubs, shallow waters, and existing natural gas infrastructure. Its excellent connectivity with both Europe and the UK makes it ideal for multi-purpose interconnectors.</p> <p><b>Challenges:</b> This zone has a relatively average annual mean wind speed potential compared to the rest of the North Sea and could also be constrained by space in the long term.</p>  |

# Characteristics of each zone have a direct impact on the configuration of LookNorthH2, making each configuration unique

## Important to note



Every zone has its characteristics; therefore, the design of an offshore energy hub would be dependent on the location and therefore the list of components required would be different. For example, Zone A has deep waters and therefore floating offshore wind is considered. The complexity level represents the complexity level of installing offshore energy hubs at specific zones, despite the zone potentially being very beneficial.

1

Zone A

**Components:**

**Electric interconnection:** HVDC

**Offshore wind platform:** Floating

**Hub platform:** Partly repurposed oil platform

**CO<sub>2</sub> storage:** Yes

**Offshore Hydrogen production:** Yes

**Offshore hydrogen storage:** No

2

Zone B

**Components:**

**Electric interconnection:** HVAC

**Offshore wind platform:** Fixed

**Hub platform:** Partly repurposed gas platform

**CO<sub>2</sub> storage:** Yes

**Offshore Hydrogen production:** Yes

**Offshore hydrogen storage:** Yes

3

Zone C

**Components:**

**Electric interconnection:** HVDC

**Offshore wind platform:** Fixed

**Hub platform:** Fully new built platform

**CO<sub>2</sub> storage:** Yes

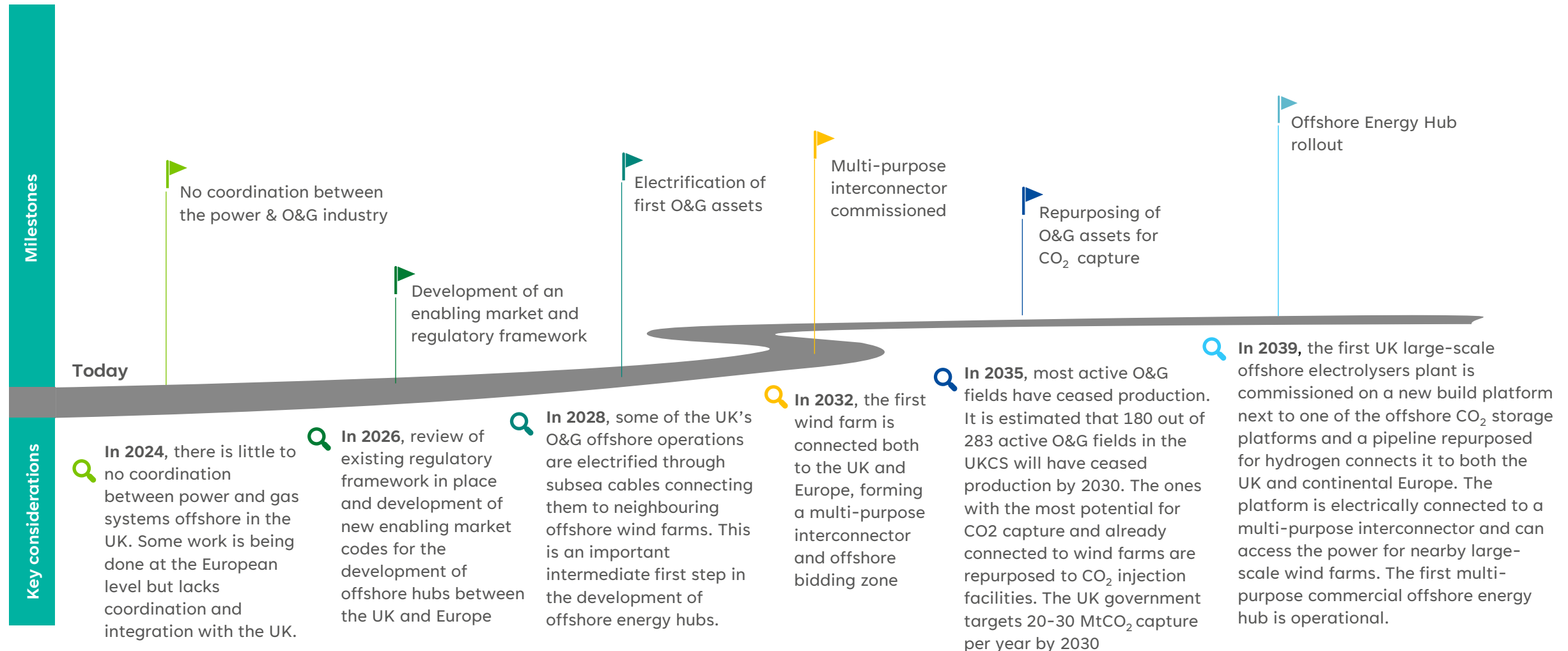
**Offshore Hydrogen production:** Yes

**Offshore hydrogen storage:** No

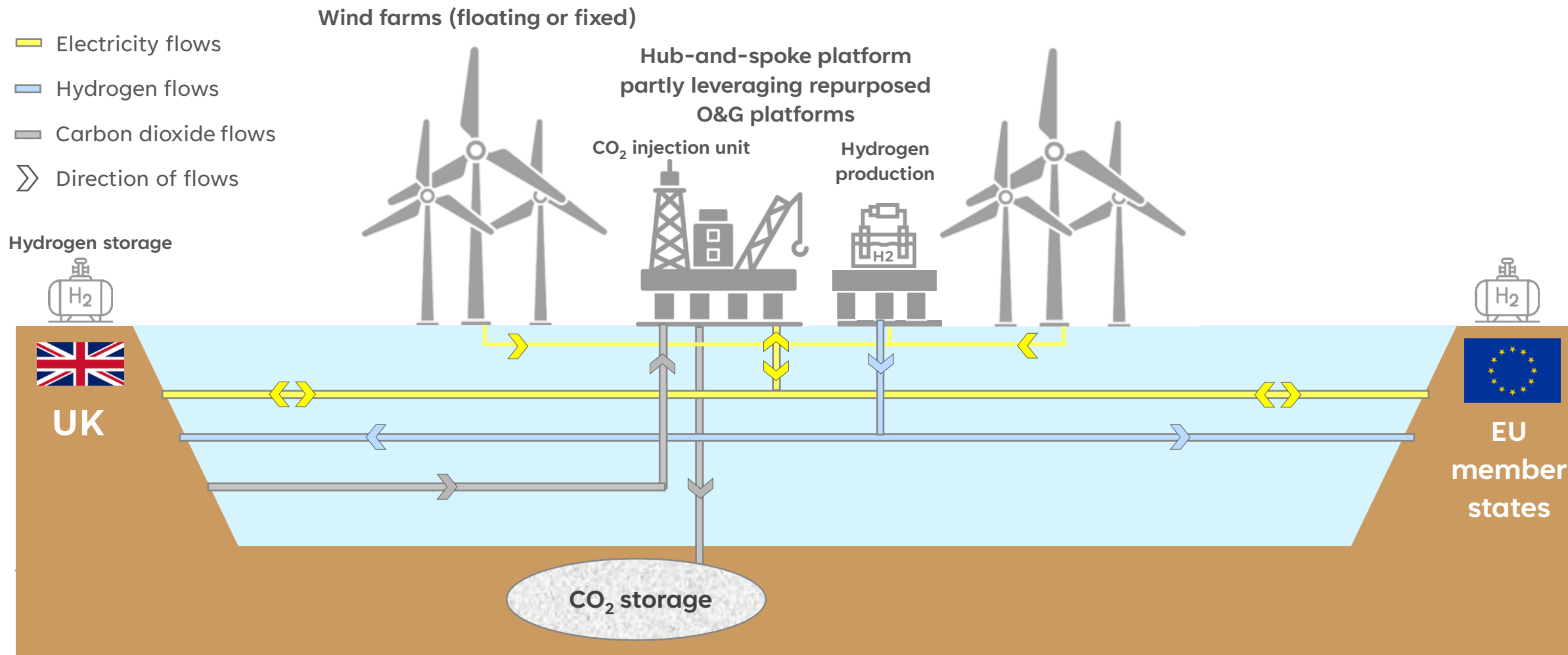
# Offshore Energy Hub Concept Configuration



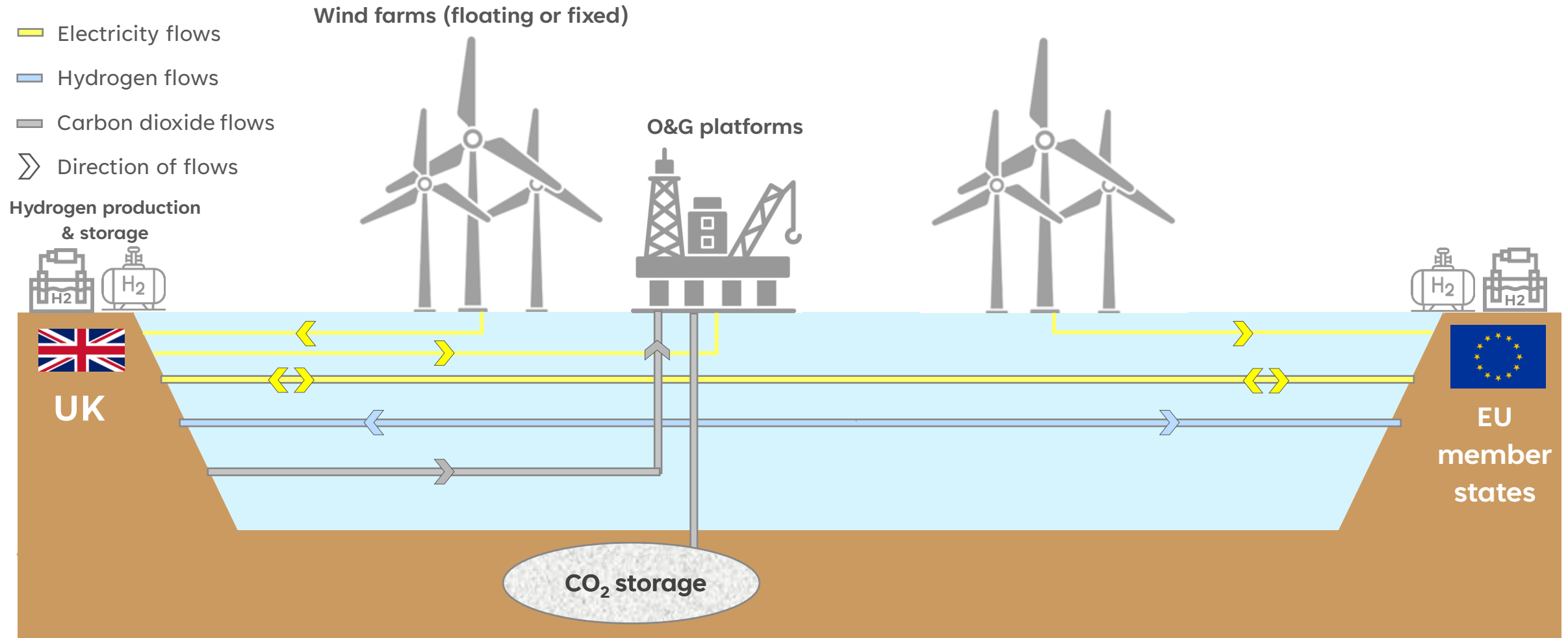
# The development of UK Offshore Energy Hubs in the North Sea is likely to follow a phased modular approach



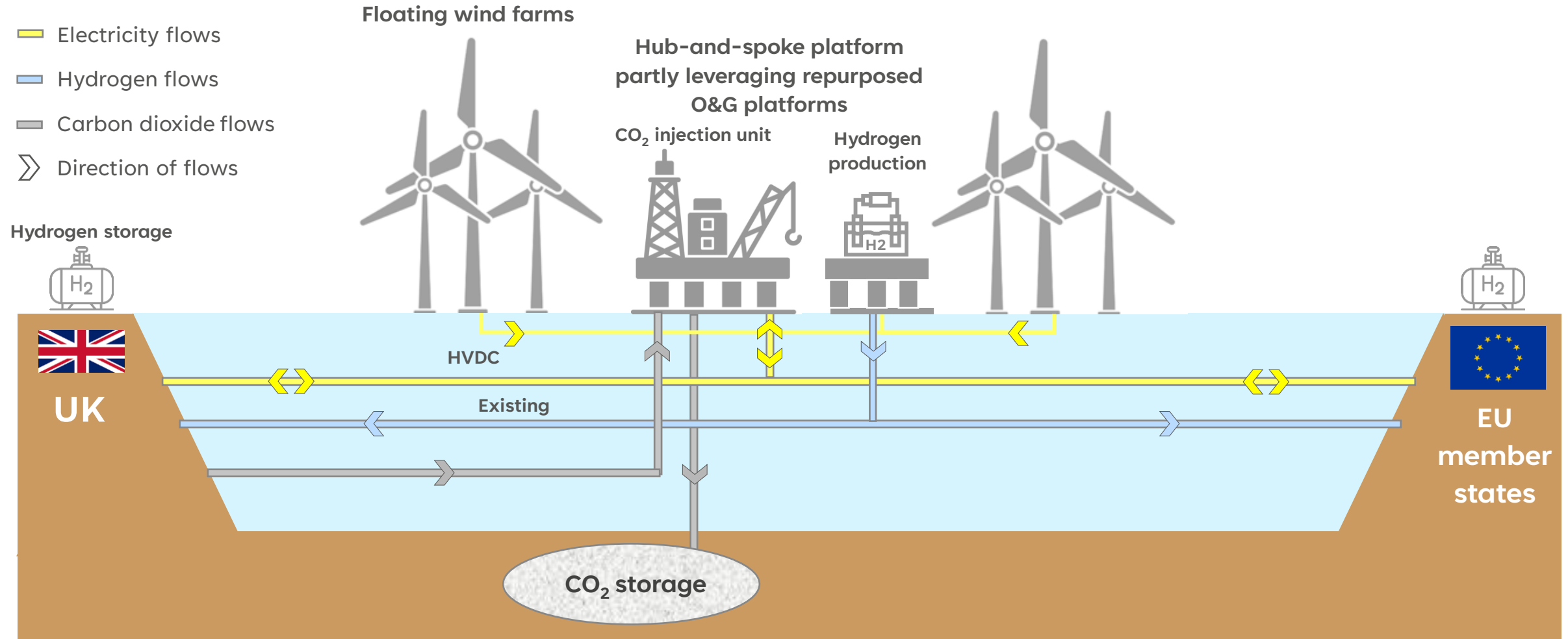
# High level offshore energy hub concept design of LookNorthH2 represents an integrated system, with connections to UK and EU



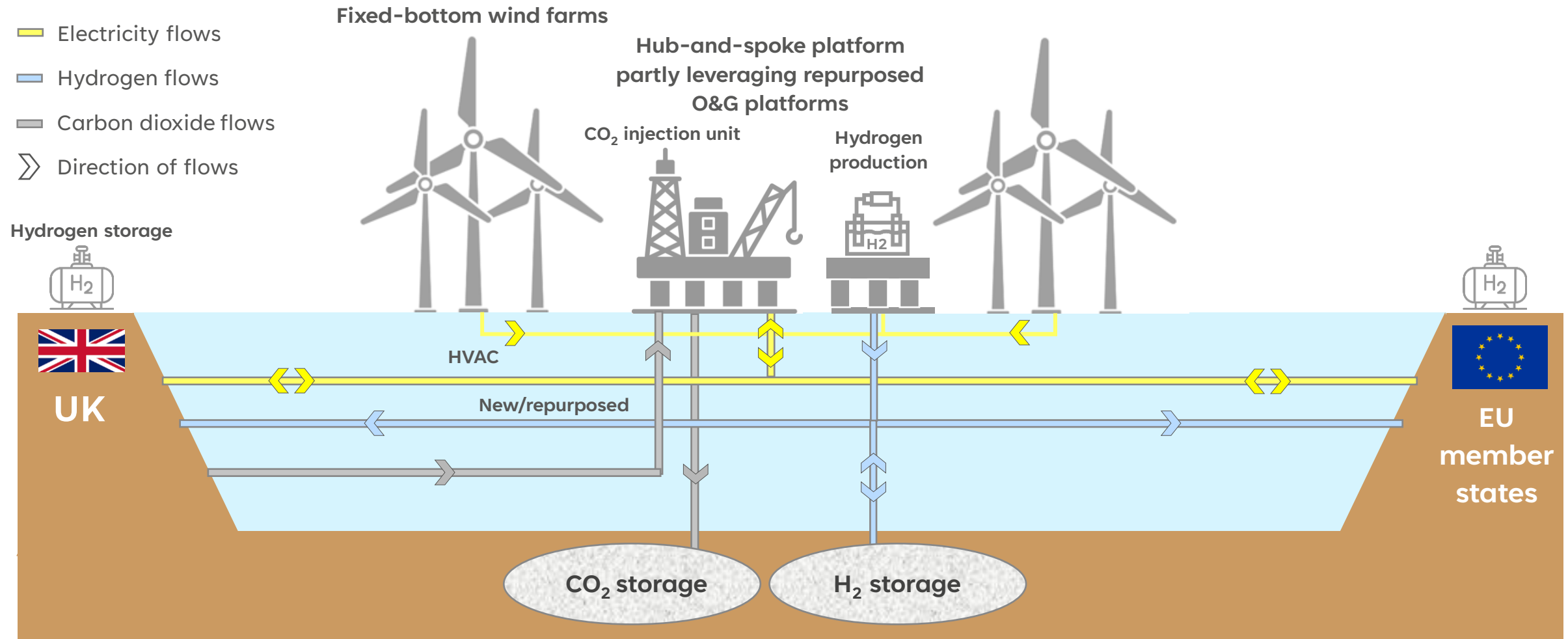
# Counterfactual - decentralised offshore electricity production, bringing electricity to the shore for hydrogen production



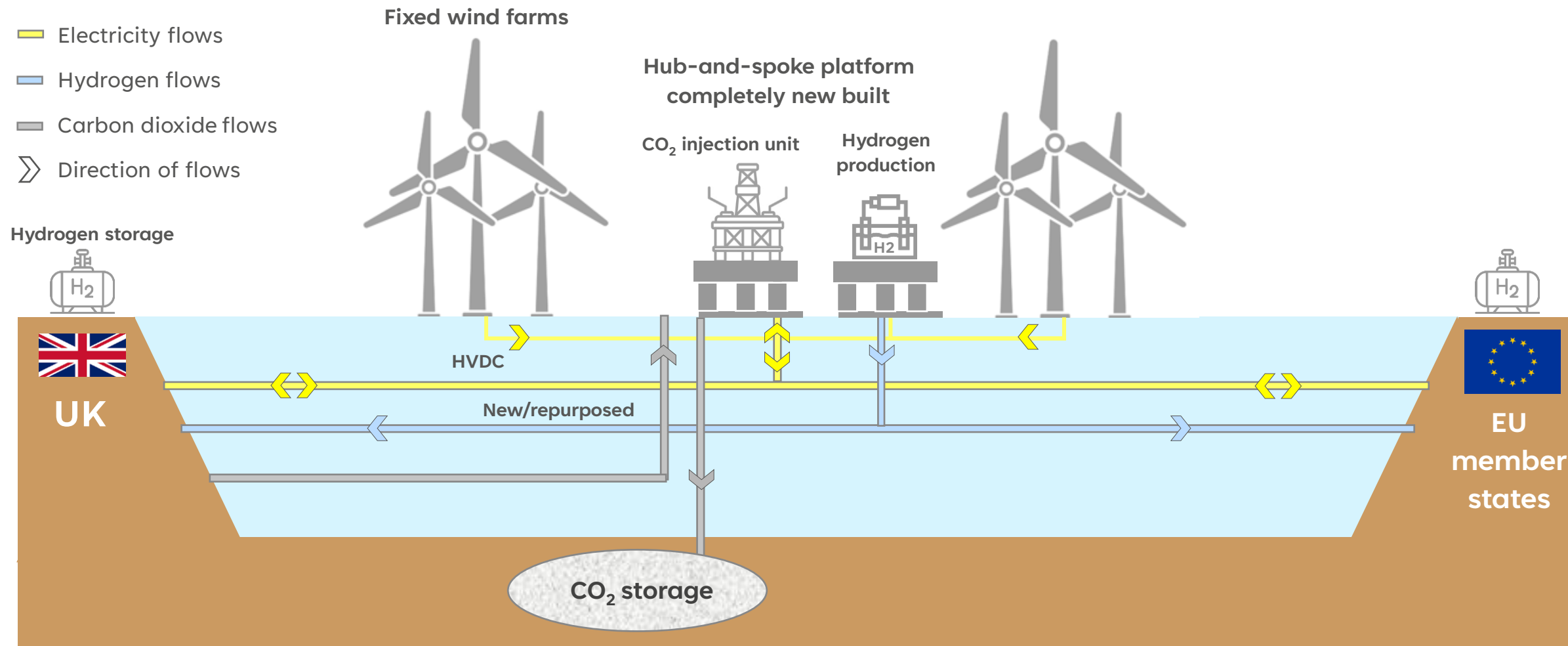
# Zone A – centralised electricity and hydrogen production via floating wind on repurposed oil platforms with CO<sub>2</sub> storage



# Zone B – centralised electricity and hydrogen production via fixed wind on repurposed gas platforms with CO<sub>2</sub> storage



# Zone C - centralised electricity and hydrogen production via floating wind on newly built platforms with no CO<sub>2</sub> storage



# 3. Economic Appraisal – Cost Benefit Analysis

Work Package 3

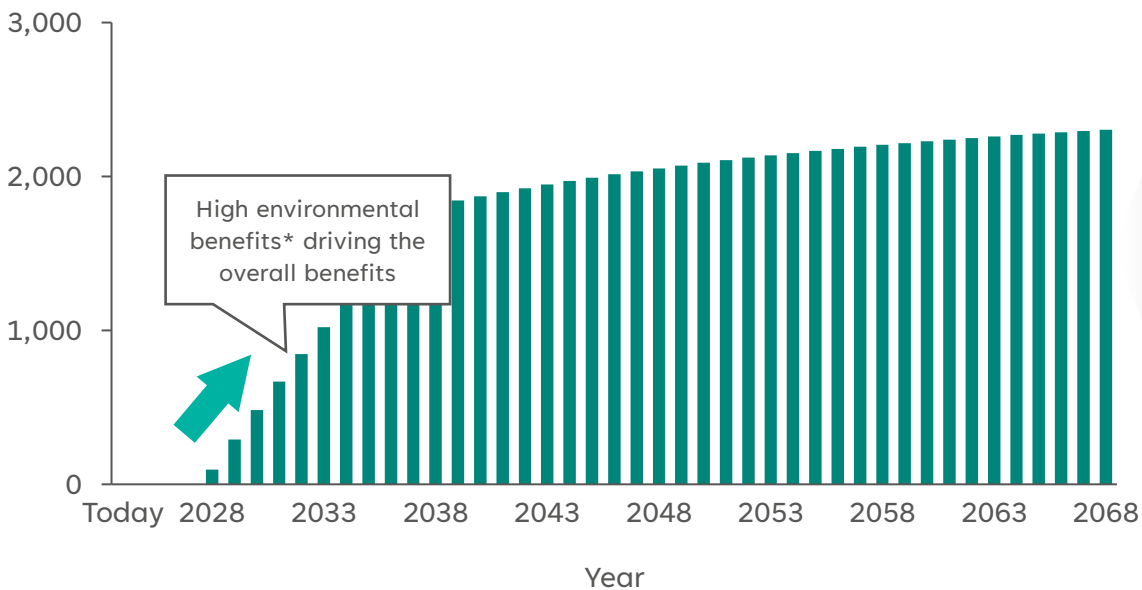
# As expected, greater infrastructure cost savings are realised with higher offshore wind capacities connected to the hub

## Key takeaways

As the number of connected offshore wind clusters increases, the cumulative discounted net financial benefits increase. Notably, with less offshore wind connected, the benefits show a slower increase between 2028 and 2068, whereas with more connections the increase in benefits is **faster**. The reason for this is the **impact of infrastructure optimisation**, as more connections result in more electricity infrastructure CAPEX & OPEX being saved.

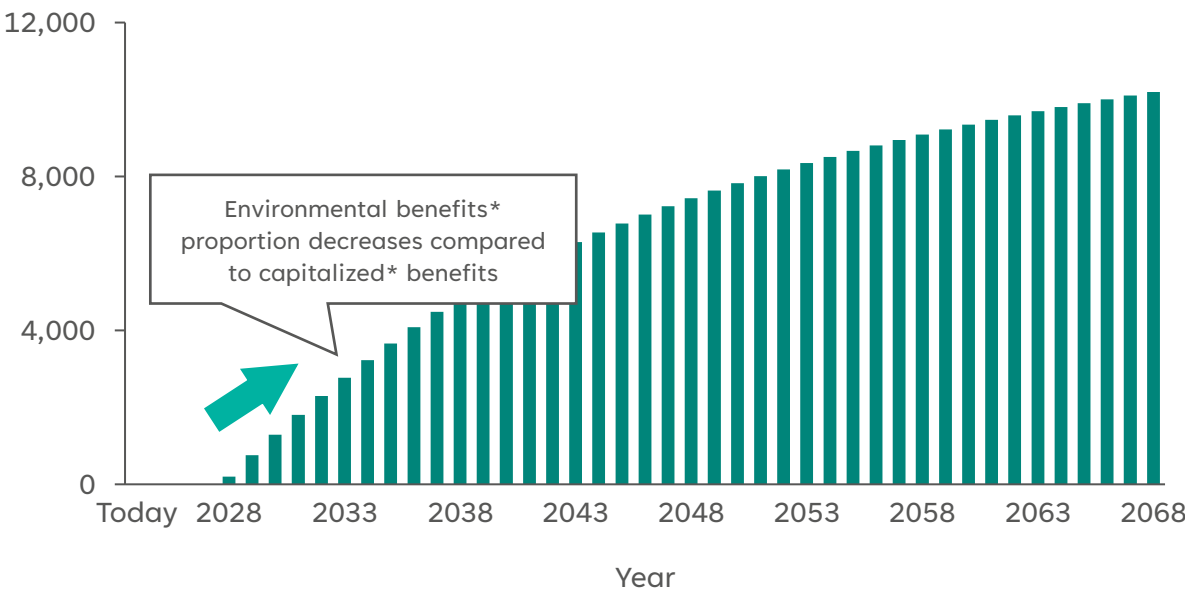
### Cumulative discounted net financial benefits—1.5 GW of connected offshore wind

Discounted NPV for an Offshore Energy Hub with 1.5 GW offshore wind, £m



### Cumulative discounted net financial benefits—15 GW of connected offshore wind

Discounted NPV for an Offshore Energy Hub with 15 GW offshore wind, £m



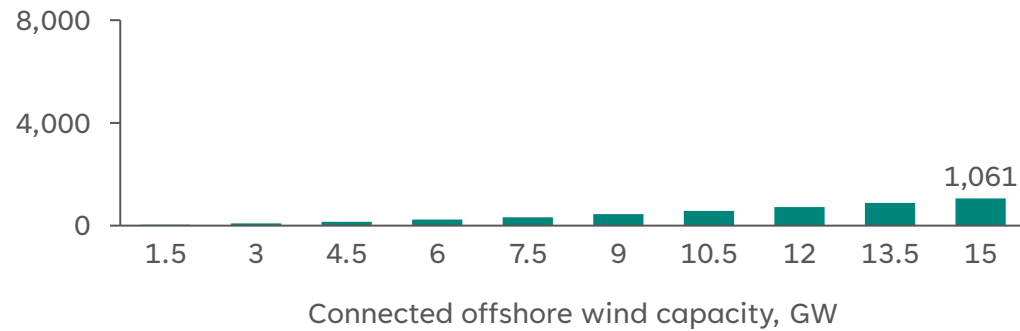
**Note:** The sharp increase in benefits at 1.5 GW is largely driven by environmental benefits, which are high compared to other benefits. At higher capacities, the increase smoothens as other benefits increase  
**Note:** Discounted NPV – Is the absolute NPV expressed as a differential between the factual and counterfactual  
**Note:** Capitalized costs are depreciated or amortized over time instead of being expensed immediately.



# Infrastructure optimisation is the main financial benefit driver of integrated OEHs followed by avoided CO<sub>2</sub> emissions

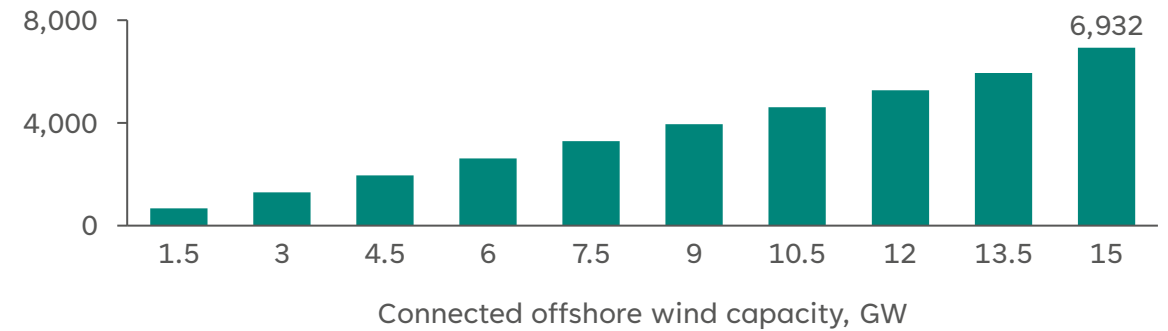
## B2. Transmission losses reduction

Cumulative discounted NPV, £m



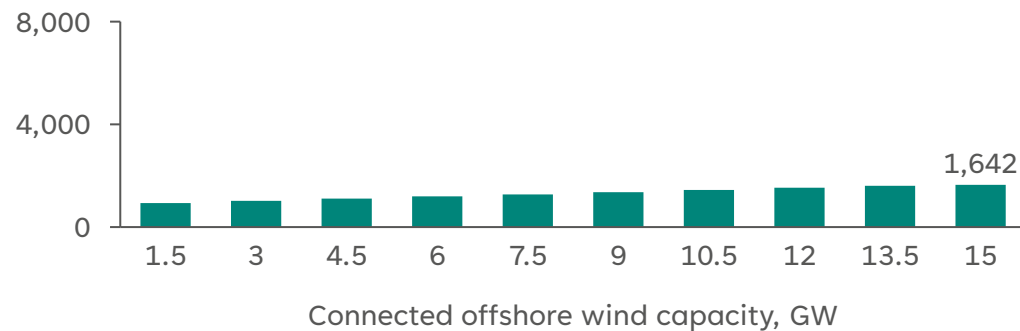
## B3. Infrastructure optimisation

Cumulative discounted NPV, £m



## BE1. & BE 2. Avoided indirect CO<sub>2</sub> Emissions - Monetised

Cumulative discounted NPV, £m



## B1. Curtailment reduction

Cumulative discounted NPV, £m

643

## B4. Avoided asset decommissioning

Cumulative discounted NPV, £m

48

**Reminder:** Curtailment reduction and avoided asset decommissioning are independent of connected capacity. Hydrogen production is also included in the counterfactual and 1.5 GW of connected capacity being enough to electrify 10 O&G offshore platforms in proximity (electrification of more platforms can be technologically challenging). For avoided asset decommissioning, one O&G offshore platform would be used for the injection of CO<sub>2</sub>.

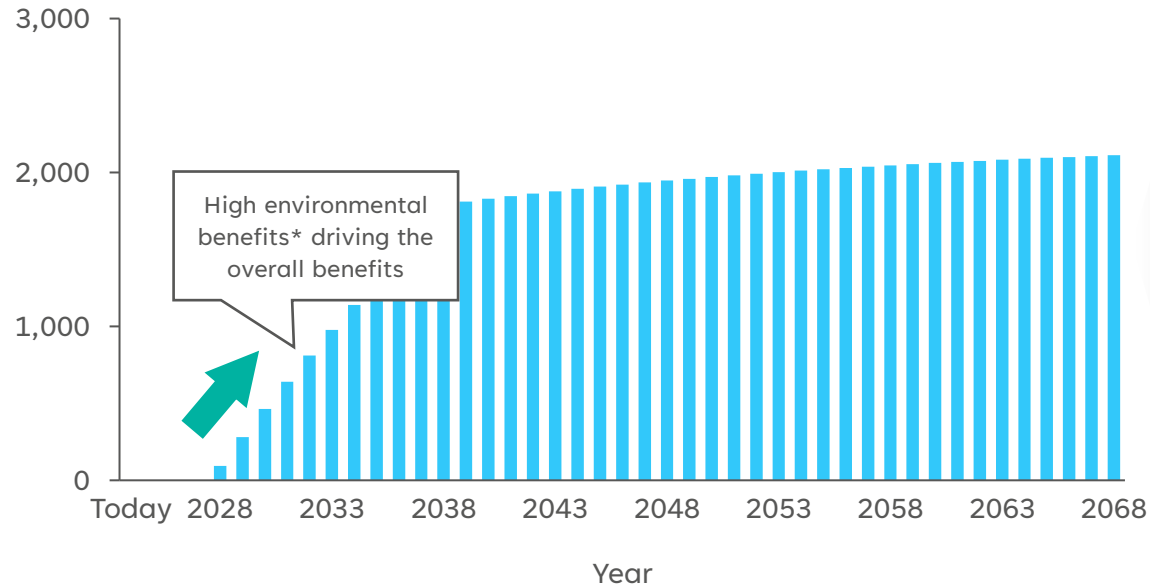
# Closer proximity to shore characterised by 'Zone B' reduces OEHs benefits but still results in positive gains

## Key takeaways

At lower connected capacities, 'Zone B' demonstrates similar cumulative discounted financial benefits in comparison to 'Zone A'. However, as more offshore wind is connected, the demonstrated benefits are almost **1.5x lower**, this is due to 'Zone B' being located closer to the shore (90 km), where 'Zone A' distance is 180 km. Due to this, the infrastructure optimisation benefits become smaller, and as these benefits are the biggest ones, they result in **overall benefits being significantly lower**.

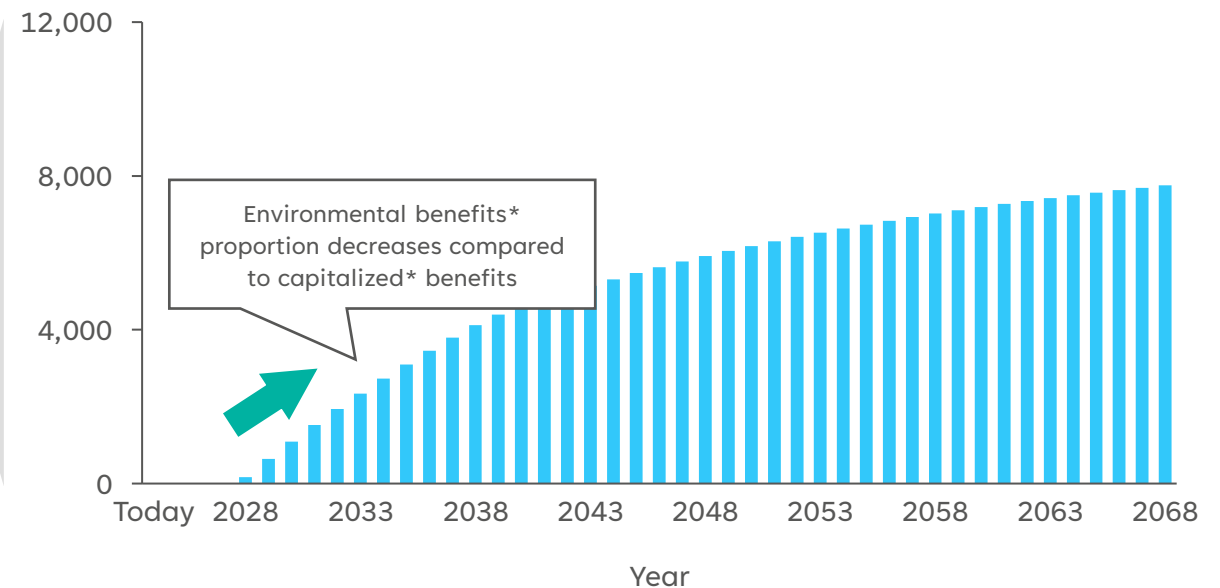
### Cumulative discounted net financial benefits—1.5 GW of connected offshore wind

Discounted NPV for an Offshore Energy Hub with 1.5 GW offshore wind, £m



### Cumulative discounted net financial benefits—15 GW of connected offshore wind

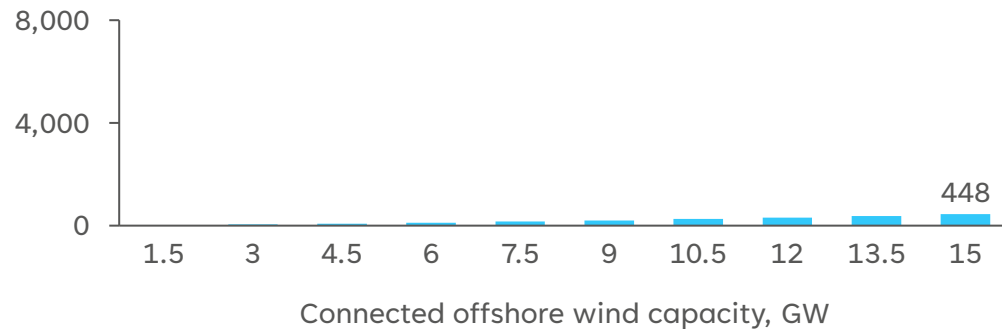
Discounted NPV for an Offshore Energy Hub with 15 GW offshore wind, £m



# In this case, the share of infrastructure optimisation in total savings reduces but remains dominant

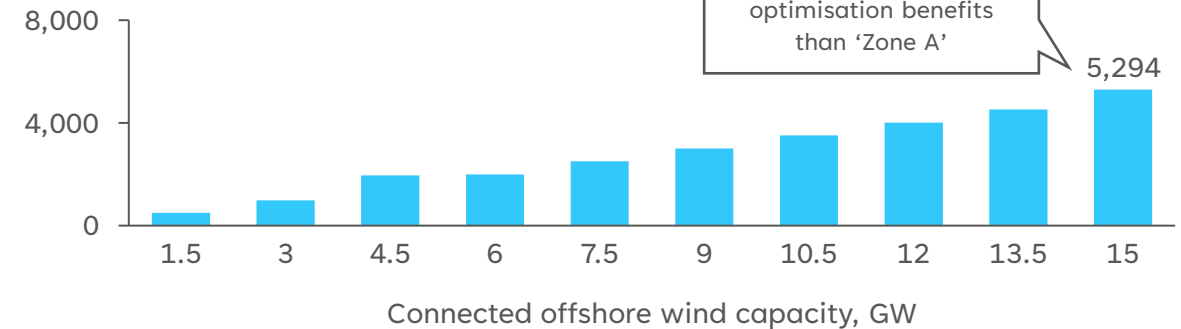
## B2. Transmission losses reduction

Cumulative discounted NPV, £m



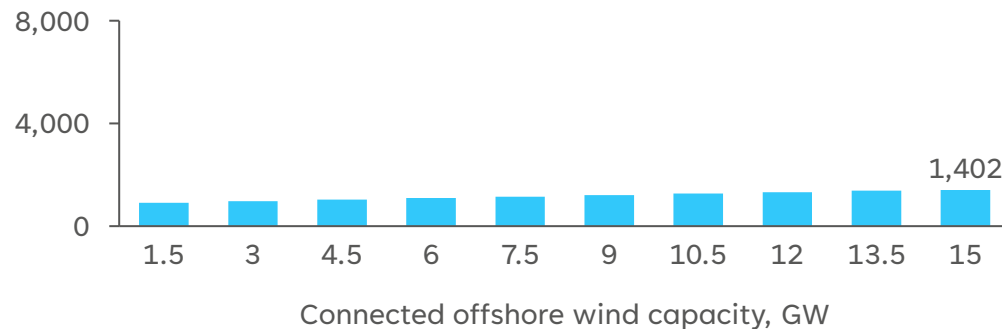
## B3. Infrastructure optimisation

Cumulative discounted NPV, £m



## BE1. & BE 2. Avoided indirect CO<sub>2</sub> Emissions - Monetised

Cumulative discounted NPV, £m



## B1. Curtailment reduction

Cumulative discounted NPV, £m

643

## B4. Avoided asset decommissioning

Cumulative discounted NPV, £m

48

**Reminder:** Curtailment reduction and avoided asset decommissioning are independent of connected capacity. Hydrogen production is also included in the counterfactual and 1.5 GW of connected capacity being enough to electrify 10 O&G offshore platforms in proximity (electrification of more platforms can be technologically challenging). For avoided asset decommissioning, one O&G offshore platform would be used for the injection of CO<sub>2</sub>.

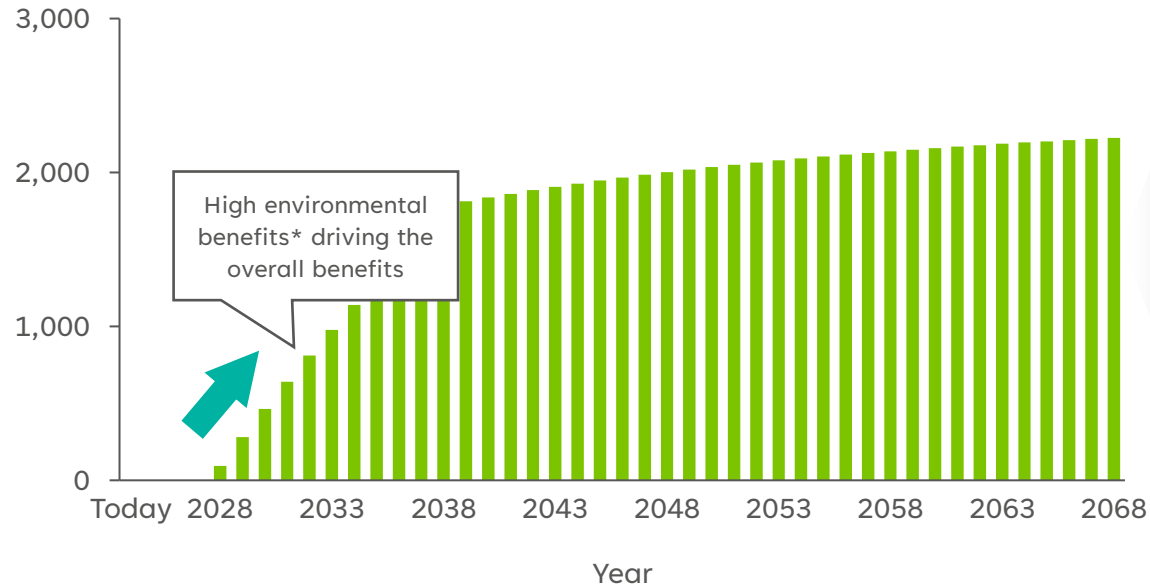
# Benefits of 'Zone C' are driven by reduced expenditure in interconnection with Europe

## Key takeaways

At higher connected capacities, 'Zone C' proves to be more beneficial than 'Zone B' due to its **closer distance to the shore of continental Europe** (120km vs. 230km), requiring less investment in electricity interconnectors. The only reason 'Zone C' shows **lower cumulative discounted financial benefits** than 'Zone B' is due to **less avoided CO<sub>2</sub> emissions** benefits, due to the electricity cable distance being shorter than 'Zone B' in both factual and counterfactual, resulting in fewer emissions.

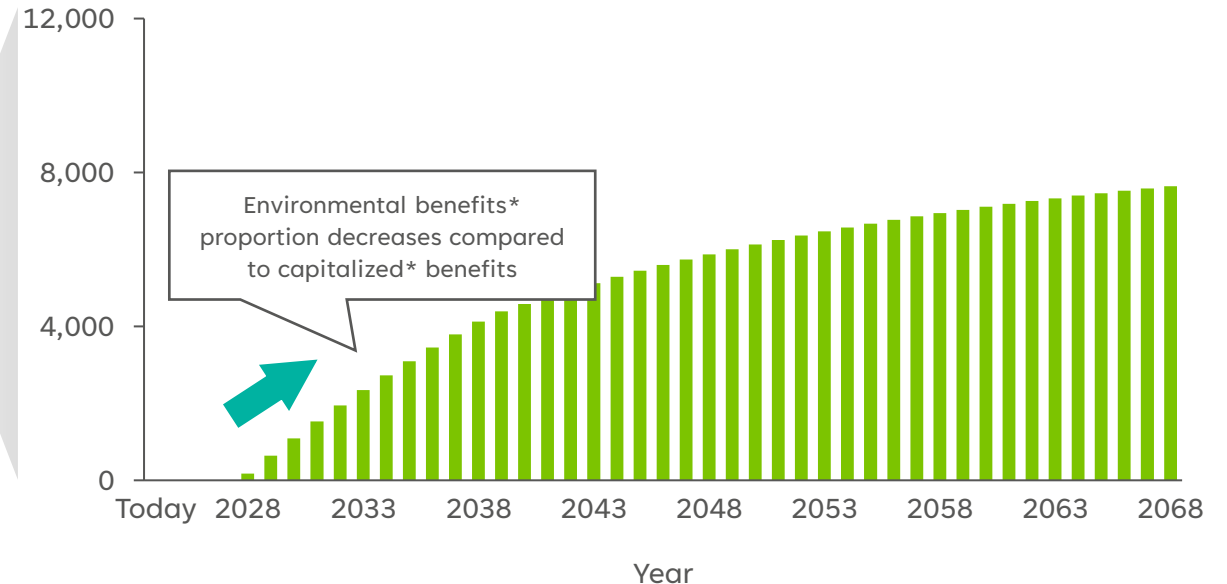
### Cumulative discounted net financial benefits—1.5 GW of connected offshore wind

Discounted NPV for an Offshore Energy Hub with 1.5 GW offshore wind, £m



### Cumulative discounted net financial benefits—15 GW of connected offshore wind

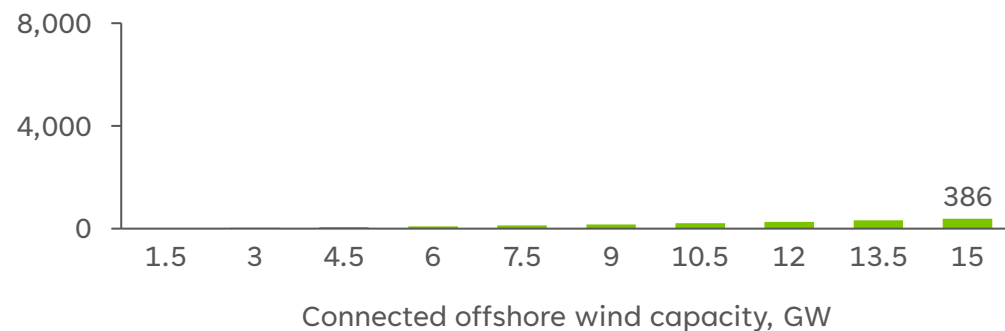
Discounted NPV for an Offshore Energy Hub with 15 GW offshore wind, £m



# ‘Zone C’ benefits resemble those in ‘Zone B’, but with lower avoided CO<sub>2</sub> emissions, due to less infrastructure required

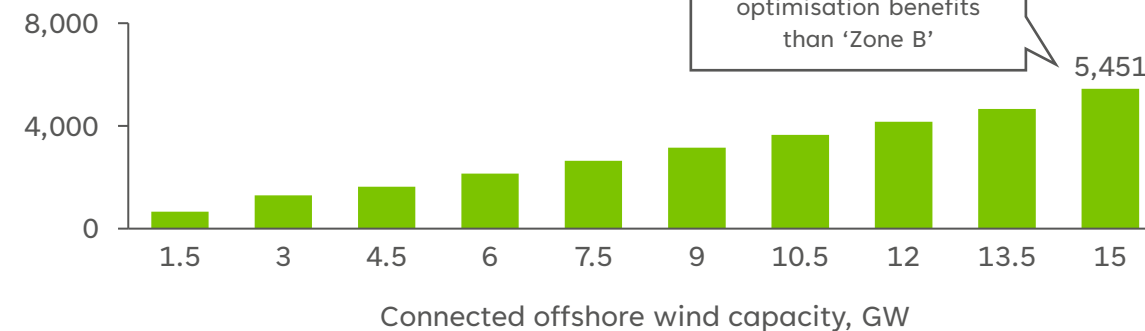
## B2. Transmission losses reduction

Cumulative discounted NPV, £m



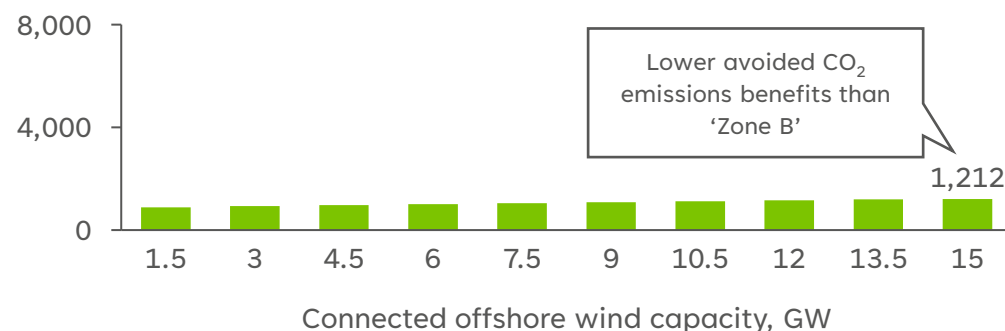
## B3. Infrastructure optimisation

Cumulative discounted NPV, £m



## BE1. & BE 2. Avoided indirect CO<sub>2</sub> Emissions - Monetized

Cumulative discounted NPV, £m



## B1. Curtailment reduction

Cumulative discounted NPV, £m

643

## B4. Avoided asset decommissioning

Cumulative discounted NPV, £m

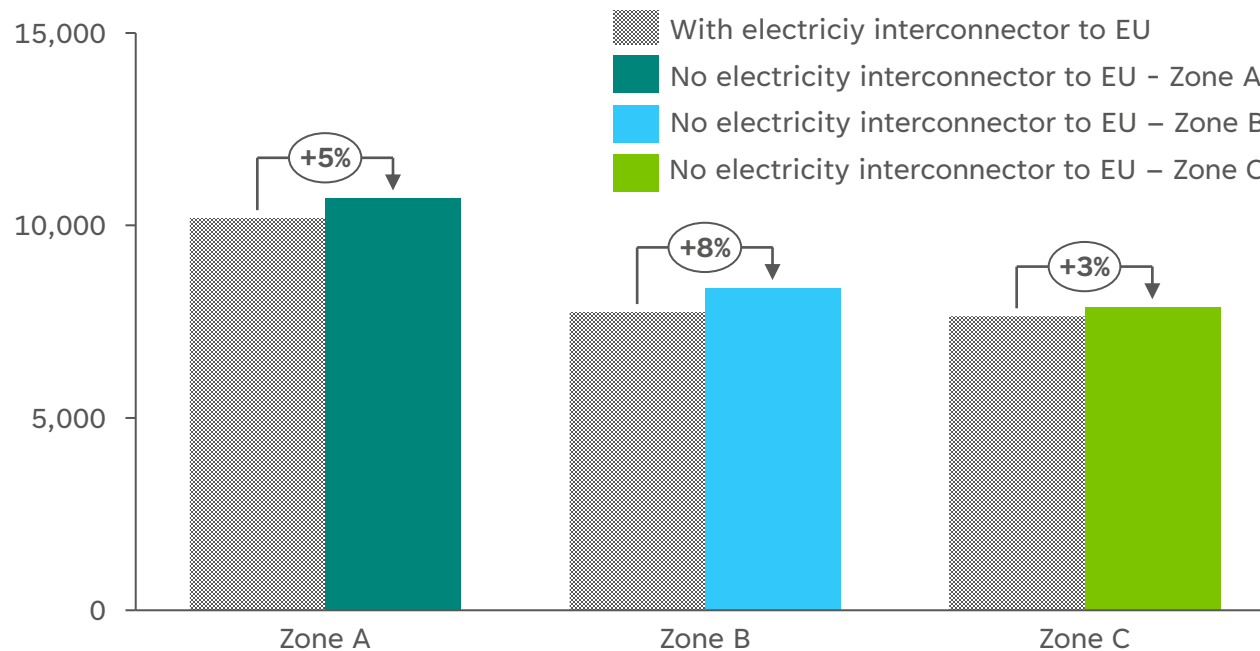
48

**Reminder:** Curtailment reduction and avoided asset decommissioning are independent of connected capacity. Hydrogen production is also included in the counterfactual and 1.5 GW of connected capacity being enough to electrify 10 O&G offshore platforms in proximity (electrification of more platforms can be technologically challenging). For avoided asset decommissioning, one O&G offshore platform would be used for the injection of CO<sub>2</sub>.

# Further analysis is required to understand the impact that interconnectors with OEHs will have on GB consumers

## Cumulative discounted net financial benefits – 15 GW of connected offshore wind

Cumulative discounted NPV for an Offshore Energy Hub at various capacities, £m

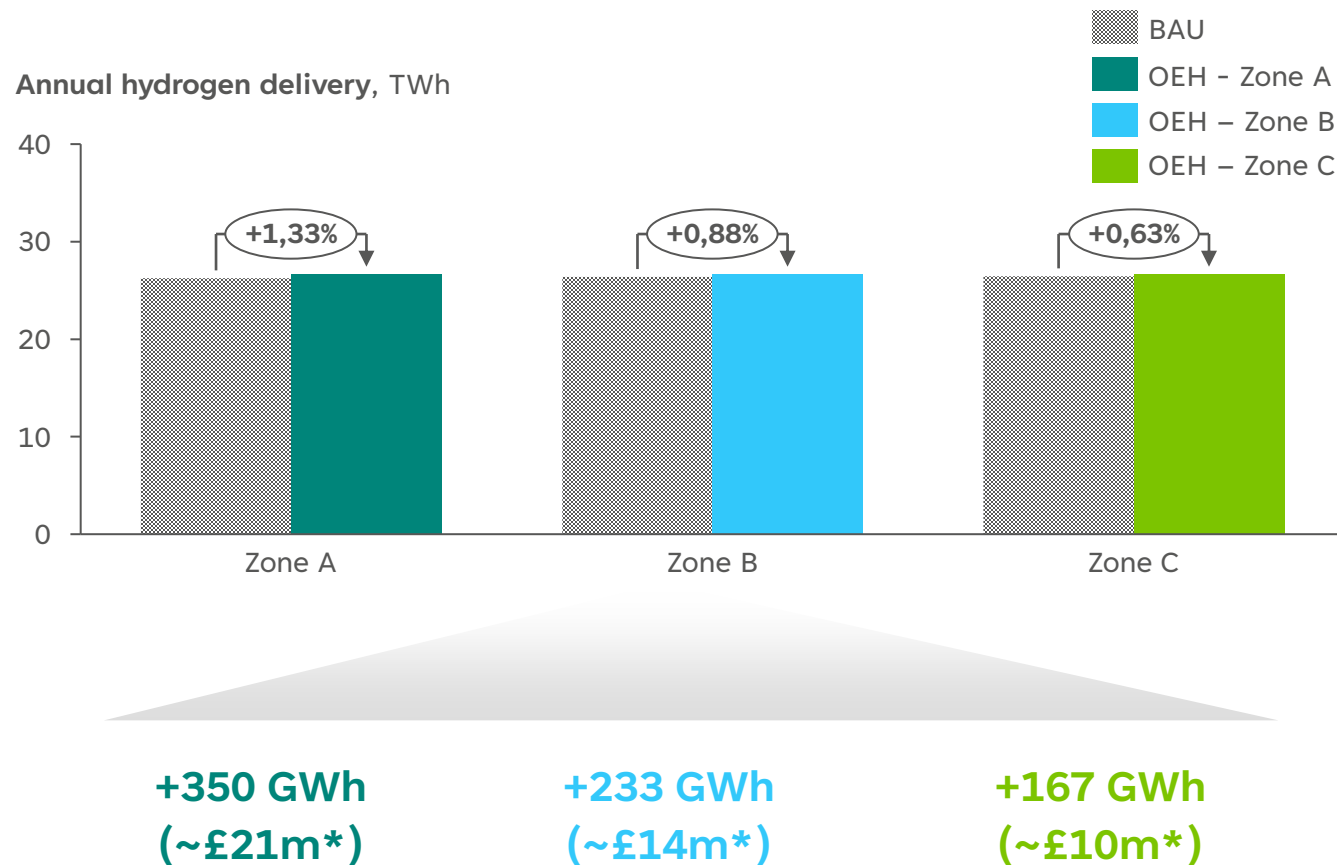


## Key takeaways

- Today, interconnectors provide significant benefits to the European power system **by enabling cross-border power trading**, resulting in greater system flexibility. The flexibility lowers price volatility in single markets and reduces curtailment.
- The concept of Offshore Energy Hubs explored in this study **also provide greater system flexibility**, mainly through adding demand-side load co-located with intermittent offshore wind generation, thus reducing curtailment.
- With this duplication of flexibility benefits, it is **unclear whether interconnectors can still justify the cost** to GB consumers under certain economic licences (i.e., cap & floor) as well as the onshore network reinforcement costs that they trigger (also paid by consumers).
- This analysis shows that it is key to consider the role of interconnectors in a future energy system with offshore energy hubs. It might be that interconnectors do provide most benefits when they are an isolated assets. **Further analysis, including a detailed CBA study with a full operability assessment is required to determine the above.**

# Offshore hydrogen production leads to more hydrogen being injected into the network, resulting in avoided losses benefits

## Annual hydrogen delivery – 15 GW of connected offshore wind



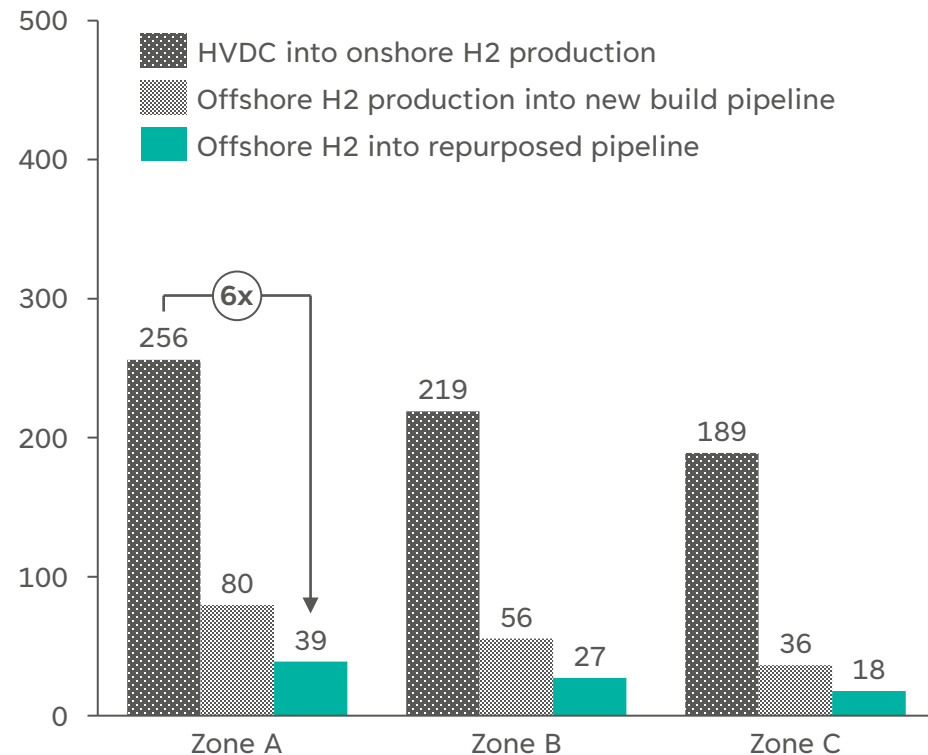
## Key takeaways

- Avoided losses benefits consider additional electricity and hydrogen that can be supplied into the network, **through minimised losses from delivering both to the shore**
- OEH offshore hydrogen production and transport to shore enables a greater volume of **hydrogen produced for the same production capacities** when compared to the BAU. This is due to the greater efficiency of hydrogen pipelines over HVDC cables.
- It should be noted that offshore colocation could also provide operational efficiency through more efficient wholesale market bidding behaviour. These benefits are hard to quantify and not captured here.
- The benefits are greatest at 15 GW of connected offshore wind capacity – ‘Zone A’, due to the location being furthest from the shore. Annually, this amounts to 350 GWh more hydrogen into the network, equating to roughly **10 TWh over the lifetime of the project**.
- At the price of hydrogen at £63 per MWh (see offshore hydrogen commercial case section), the annual pre-discounted savings are ~£22m and **~£661m** over the lifetime of the project.

# Additionally, offshore production proves to be the most cost-efficient solution when leveraging repurposed pipelines

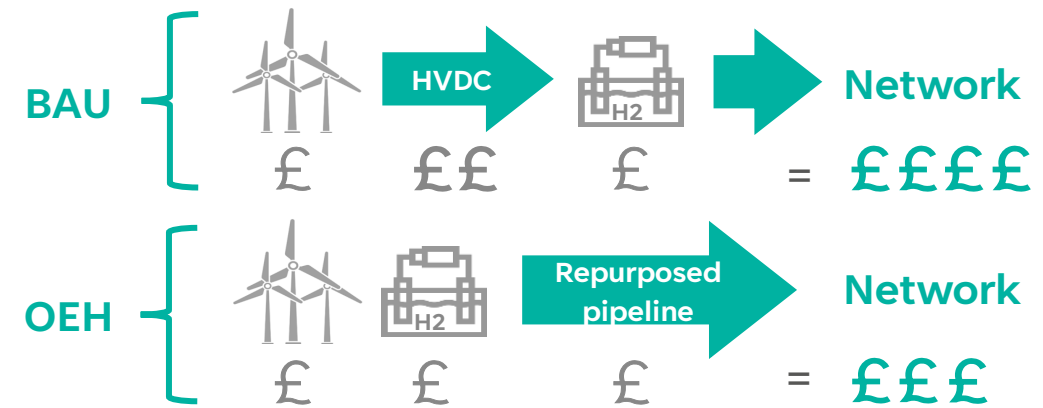
## Cost of energy transport – 15 GW of connected offshore wind

### Cost of transporting 1 TWh of hydrogen into the network\*, £m



## Key takeaways

- Offshore hydrogen pipelines can help deliver more affordable hydrogen to the market by reducing the cost of energy transportation.
- For the same quantity of hydrogen, the OEH is able to leverage hydrogen pipeline only through colocation with offshore wind, and thus save on the high costs of HVDC cables.
- Although there are benefits to retaining electricity infrastructure to the hub, the comparison of cost of energy transport for hydrogen delivered in the onshore network clearly shows that hydrogen pipeline are significantly more affordable. This makes the case for non-grid connected offshore wind electrolysis, which should be explored further in other innovation project or developers' R&D.





# Offshore hydrogen production also enables greater CO<sub>2</sub> savings from additional clean energy injected as well as land savings

## Key takeaways

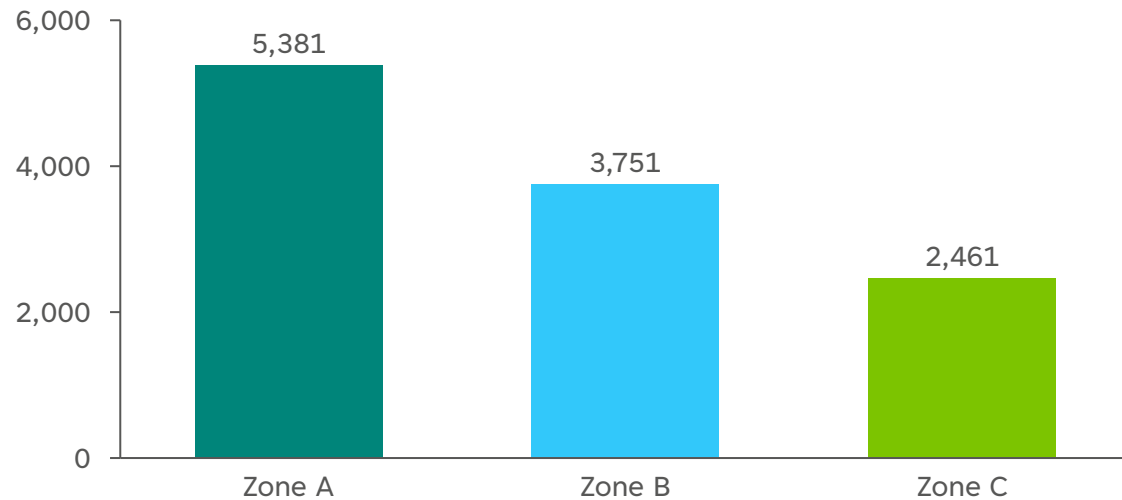
As more hydrogen is injected into the network, more natural gas is displaced and its associated emissions. Most hydrogen is delivered at 15 GW of connected offshore wind in 'Zone A', resulting in the largest CO<sub>2</sub> reduction – **5,381 ktCO<sub>2</sub>**

## Key takeaways

Moving hydrogen production offshore enables onshore land saving. At 15 GW of connected offshore wind at all zones, ~ 4 GW of PEM electrolyzers are installed – equaling **57,000 m<sup>2</sup> (5.7 ha)\***. The UK, and particularly England, is one of the most densely populated country in the world, making land savings particularly valuable.

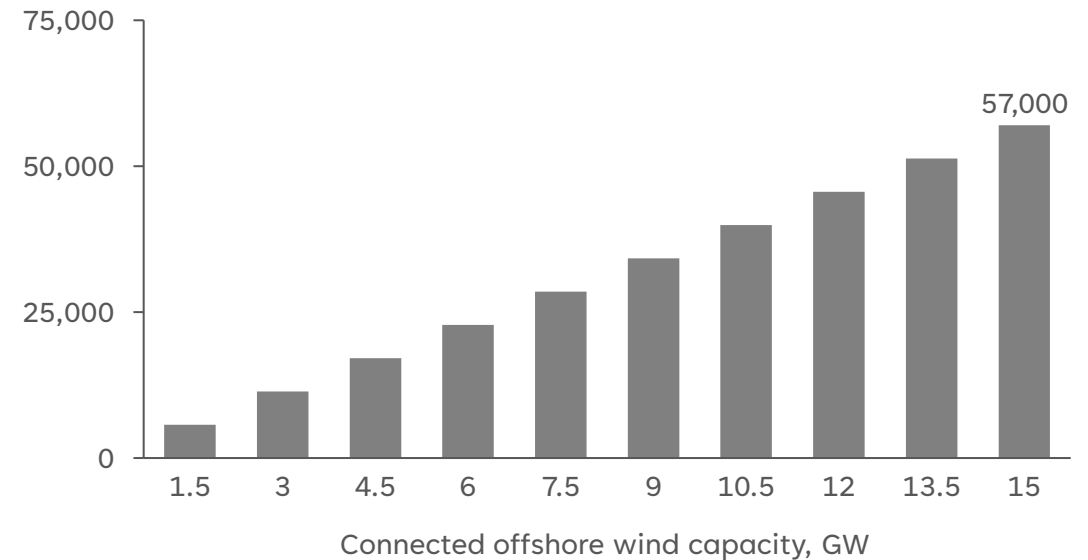
## CO<sub>2</sub> avoided – 15 GW of connected offshore wind

Cumulative avoided CO<sub>2</sub> emissions, ktCO<sub>2</sub>



## Land saved – various connected offshore wind capacities

Land saved, m<sup>2</sup>



# OEHS could also create significant environmental and social benefits

## Health & Safety

3 Good Health & Well Being



OEHS **reduce CO<sub>2</sub> emissions** by displacing emission intensive fuels and **therefore impact health outcomes**, through improved air quality. According to the National Library of Medicine<sup>1</sup>, 4,434 tCO<sub>2</sub> causes one excess death globally over a 80-year period.

## Biodiversity

15 Life On Land



Moving hydrogen production offshore would **prevent electrolyser development onshore** and therefore would **reduce land use**. However, there could be a risk to ocean biodiversity that needs to be investigated further.

## Operational Integration

11 Sustainable Cities & Communities



By reducing transmission infrastructure requirements, OEHS **enable more efficient uses of resources**, reducing reliance on critical minerals and increasing supply chain resilience

## Avoid CO<sub>2</sub> Intensive General Reinforcement

9 Industry, Innovation & Infrastructure



OEHS **reduce the reliance on electricity infrastructure**, leading to the **reduction in costs** to operate electricity networks, realising cost savings to energy bills. Additionally, OEHS provide **direct emissions savings** from minimising construction works.

## Supporting Clean Energy Access

7 Affordable & Clean Energy



OEH approach should maximise the value of electricity and gas infrastructure, **lower the levelised cost of electricity**, and accelerate the hydrogen economy by delivering more affordable green hydrogen.

## Green Job Creation and Economic Growth

8 Decent Work & Economic Growth



**Creation of new jobs** for operating, servicing, and construction of the offshore hub. This would be through direct construction of the facility and indirectly through the supply chain. Additionally, jobs on existing O&G platforms are maintained through CO<sub>2</sub> injection. As a result, enhancing the **economic growth of these local areas**.

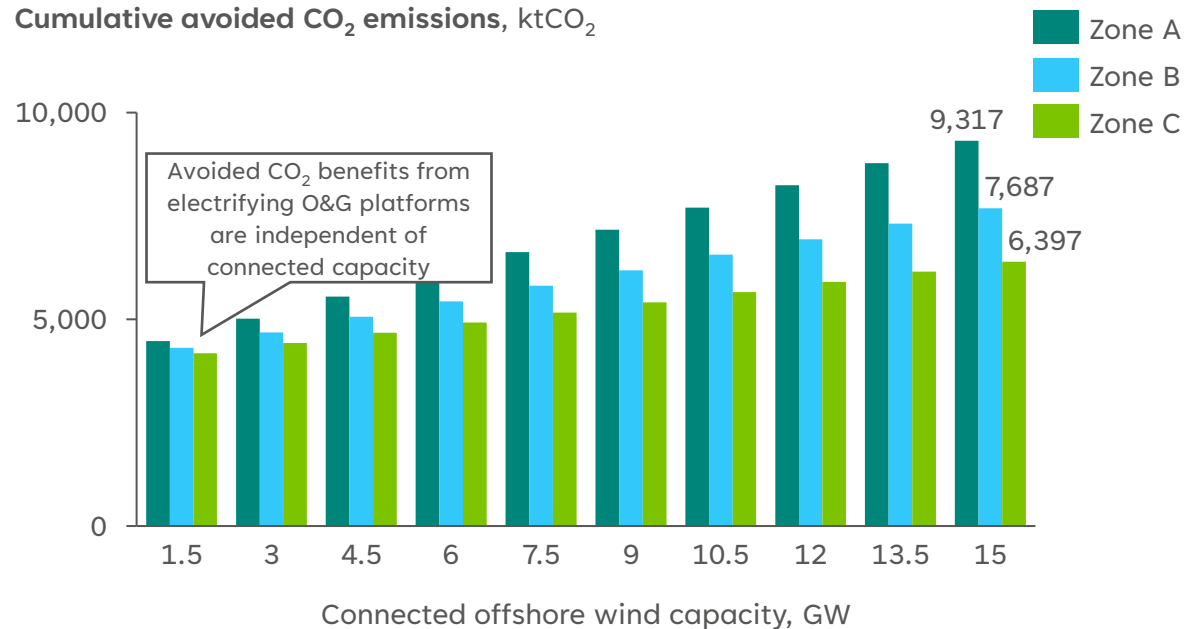
# Avoided indirect CO<sub>2</sub> emissions and jobs maintained/created are highly driven by connected offshore wind capacity

## Key takeaways

The initial benefits are due to electrification of O&G platforms, independent of connected capacity, resulting in more benefits at 1.5 GW. The avoided losses are linear with connected capacity, resulting in a linear increase of avoided CO<sub>2</sub> emissions. The highest CO<sub>2</sub> reduction is achieved at **Zone A 15 GW – 9,317 ktCO<sub>2</sub>**

## BE1. & BE 2. Avoided indirect CO<sub>2</sub> Emissions – non-monetized

Cumulative avoided CO<sub>2</sub> emissions, ktCO<sub>2</sub>

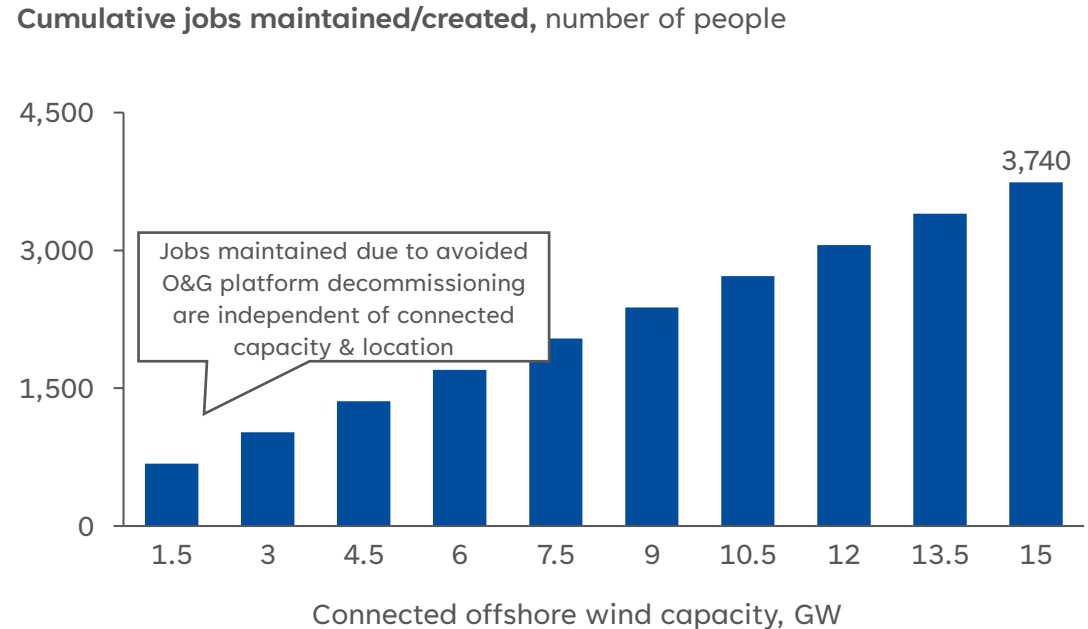


## Key takeaways

One O&G platform is used for CO<sub>2</sub> injection - maintaining the jobs related to it, therefore being independent of connected capacity and location. The jobs created relate to constructed platforms for electrolyser co-location, increasing linearly with connected capacity. Maximum benefits are achieved at **15 GW – 3,740 people**

## BS1. Direct jobs maintained/created

Cumulative jobs maintained/created, number of people

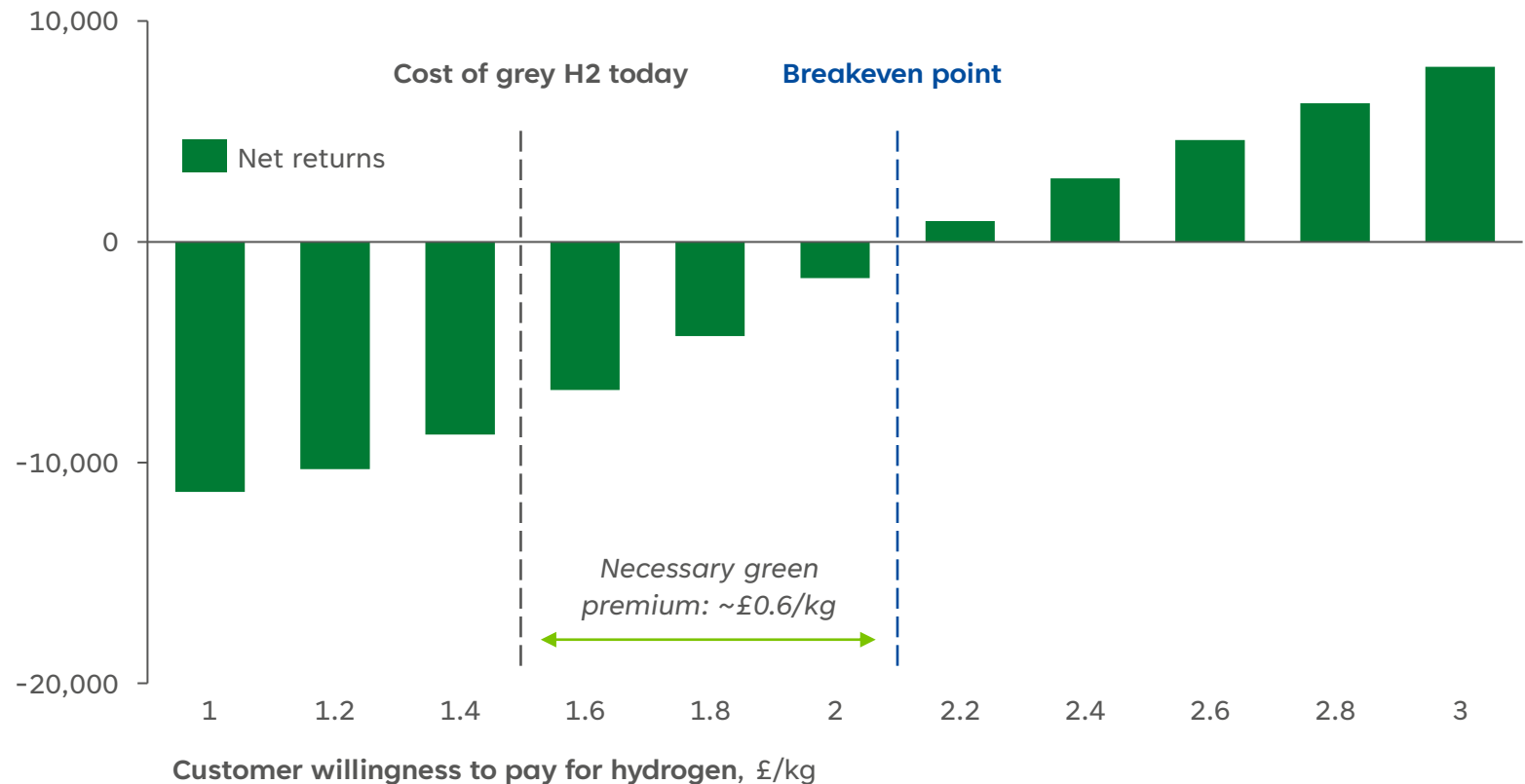


# Offshore hydrogen commercial case

# For OEHs to be developed and deliver system benefits, the business case must be attractive for each individual developers

H2 market prices must be at least ~£21/kg (£63/MWh) for the Offshore Energy Hub partners to break-even

Estimated net present value return for a 3GW offshore electrolyser plant located in zone A in 2050, £M



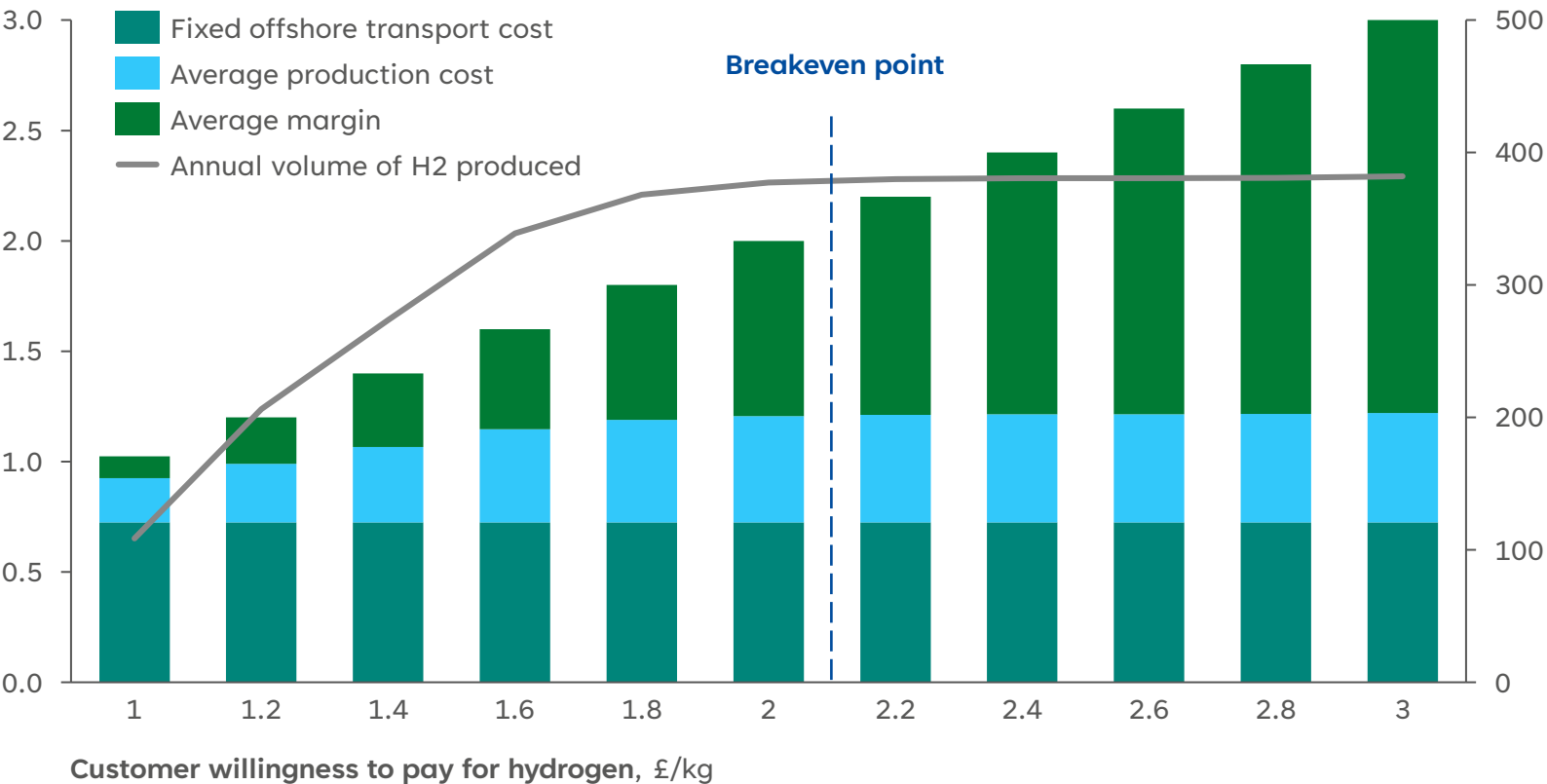
## Key takeaway

- In this simple example, the lowest price of hydrogen the developer will be able to sell its production to **breakeven is £21/kg (£63/MWh) in 2050**. This price remains significantly more expensive than the benchmark cost of grey hydrogen (defined as pre-energy crisis).
- This create a so-called green premium which is uncertain the market is going to accept.
- The breakeven point would be much higher in 2040 and 2030, which in turns increases the green premium in early market development.

# Offshore transportation is the largest share of costs at relatively low H2 prices. It holds most levers to bridge the premium gap.

Offshore transportation accounts for 35% of the costs and margins required to reach breakeven (£2.1/kg)

Cost breakdown for a 3GW offshore electrolyser in zone A in 2050, £/kgH2    Annual H2 volume produced, kt of H2



Key takeaway

- The estimated offshore transportation cost for ‘Zone A’ is **£0.72/kg**, approximately half of the total price of grey H2 today<sup>1</sup> (pre-energy crisis).
- Offshore transportation costs represent **35% of the cost of delivering hydrogen to shore**, including the margins required for the hub to turn a profit.
- As such, **more innovation** is required to reduce the cost of offshore hydrogen transportation and bridge the premium gap.
- Ensuring offshore hydrogen competitive and delivering the system benefits provided by offshore energy hub will require **supporting innovation to drive offshore hydrogen transportation costs down**.

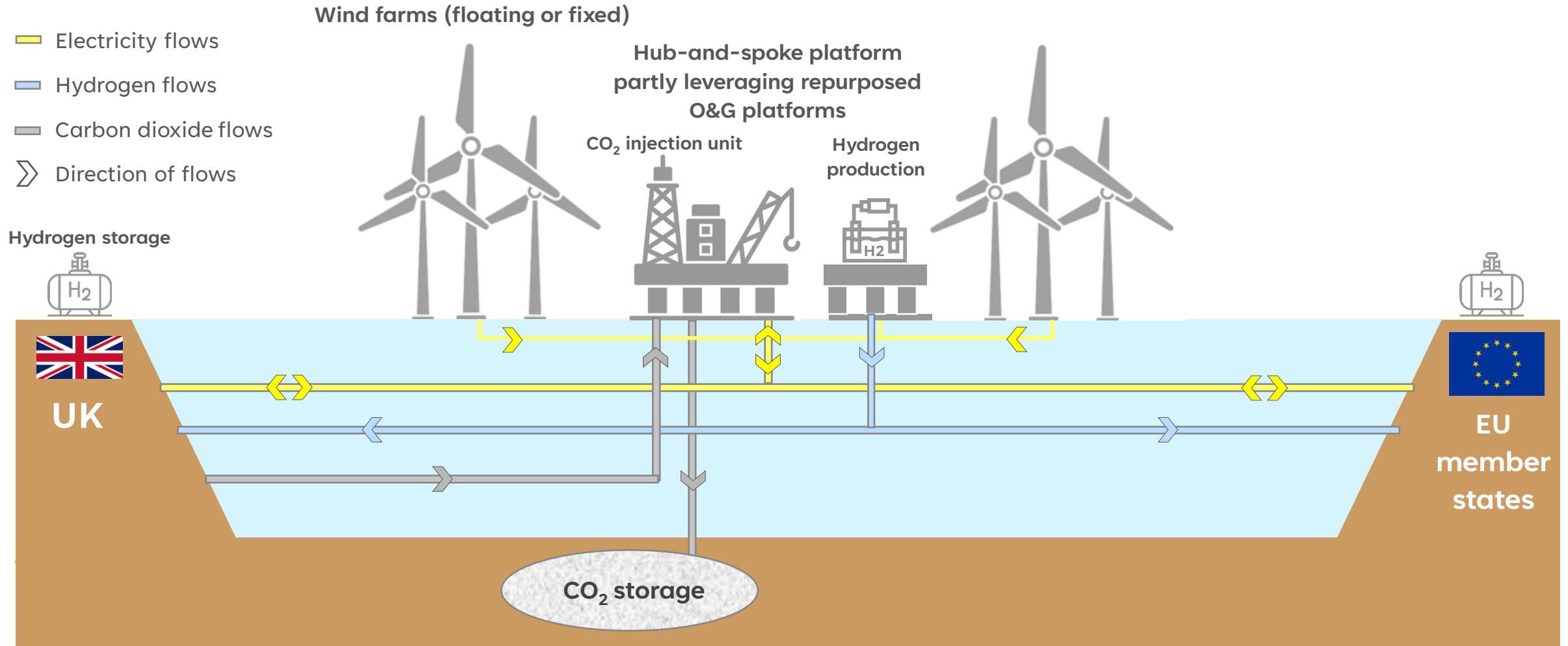
# 4. Regulatory, policy and market codes gaps

Work Package 4

# 4.1 Introduction



# High-level Offshore Energy Hub (OEH) concept of LookNorthH2 representing an integrated system, connected to the UK and EU

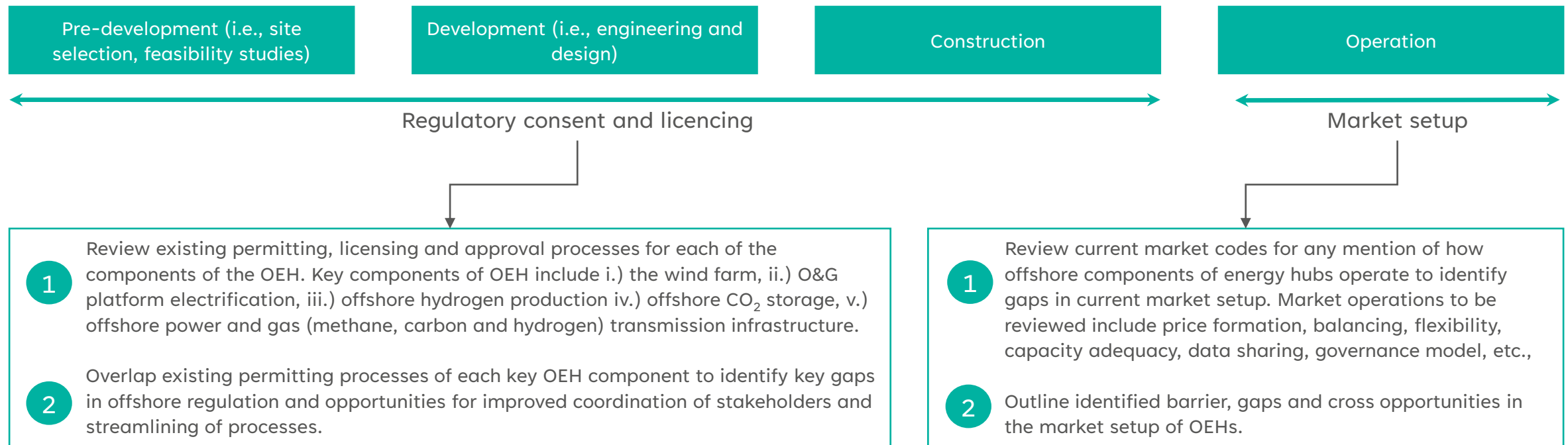


# We analysed existing regulatory processes and market codes to uncover gaps and barriers hindering OEH development

**Goal**

Identify existing barriers and potential enablers for offshore energy hubs developers to reach commercial scale project FID

## Phases in the OEH development cycle



# We have worked with the (N)ESO and regulators to solidify our analysis and confirm our insights



Goal

Identify existing barriers and potential enablers for offshore energy hubs developers to reach commercial scale project FID

## Phases in the OEH development cycle



## Stakeholders to be engaged in later phases:

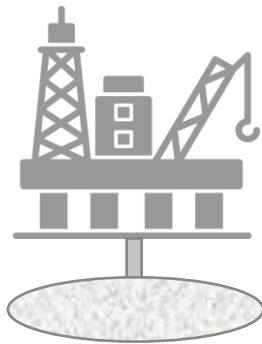


# Appropriate regulatory, commercial and market framework should enable investments from all industry stakeholders

1. Offshore wind developers



2. Offshore CO<sub>2</sub> transport & storage developers



3. Hydrogen production developers



4. Offshore electricity transmission networks



5. Offshore hydrogen transmission networks



We have worked with organisations in each stakeholder group to better understand their vision of offshore energy hubs and gather insights on specific barriers, but also opportunities, they foresee in the development of offshore energy hubs

## 4.2 Regulatory gaps

# OEH regulations should create an enabling landscape for investment while protecting the environment and consumers

## The regulatory framework for offshore energy hubs should:

- 1 Foster development of diversified energy infrastructure within offshore energy hubs to enhance resilience against supply disruptions
- 2 Improve investor confidence in renewable energy infrastructure which promotes long-term energy independence
- 3 Ensure minimal impact on marine ecosystems through strict regulations on emissions, waste disposal and habitat preservation
- 4 Enforce safety standards to minimise the risk of accidents, substance spills and other hazardous incidents

## Regulatory framework objectives

Energy security

Environmental protection

Consumer safety

# However, the current regulatory consenting regime is fragmented with multiple regulators, creating uncertainty



The key problem faced by the development of OEH lies in the fragmentation of regulations, where siloed frameworks and processes across different sectors impede system integration projects.

This challenge has been reported by industry players and acknowledged by the regulators...

- Misalignment of approval timings for OSW farm and O&G electrification, coupled with a lack clarity on timing of certain regulatory decisions (e.g., environmental statement decision) from stakeholders.
- Restrictive regulations such as the AR6 subsidy round not being available to hybrid wind farms and current CfD agreement for offshore wind developers restricting supply of electricity to O&G platforms
- The economic licence for offshore CO<sub>2</sub> storage currently only enables regulated commercial models due to the initial natural monopoly nature of the value chain. However, as the market develops and CO<sub>2</sub> becomes traded beyond borders, new merchant business models should be introduced under the economic licence.



... with several implications to offshore system integration projects



## Technical

- There is no incentive for offshore wind farms to be integrated to other offshore assets and land, so a true form of offshore system integration cannot be implemented.



## Economic

- Regulatory fragmentation creates uncertainty in project planning, which could reduce investor confidence and hinder the economic viability of OEHs. This leads to OEH developers being unable to reach FID.



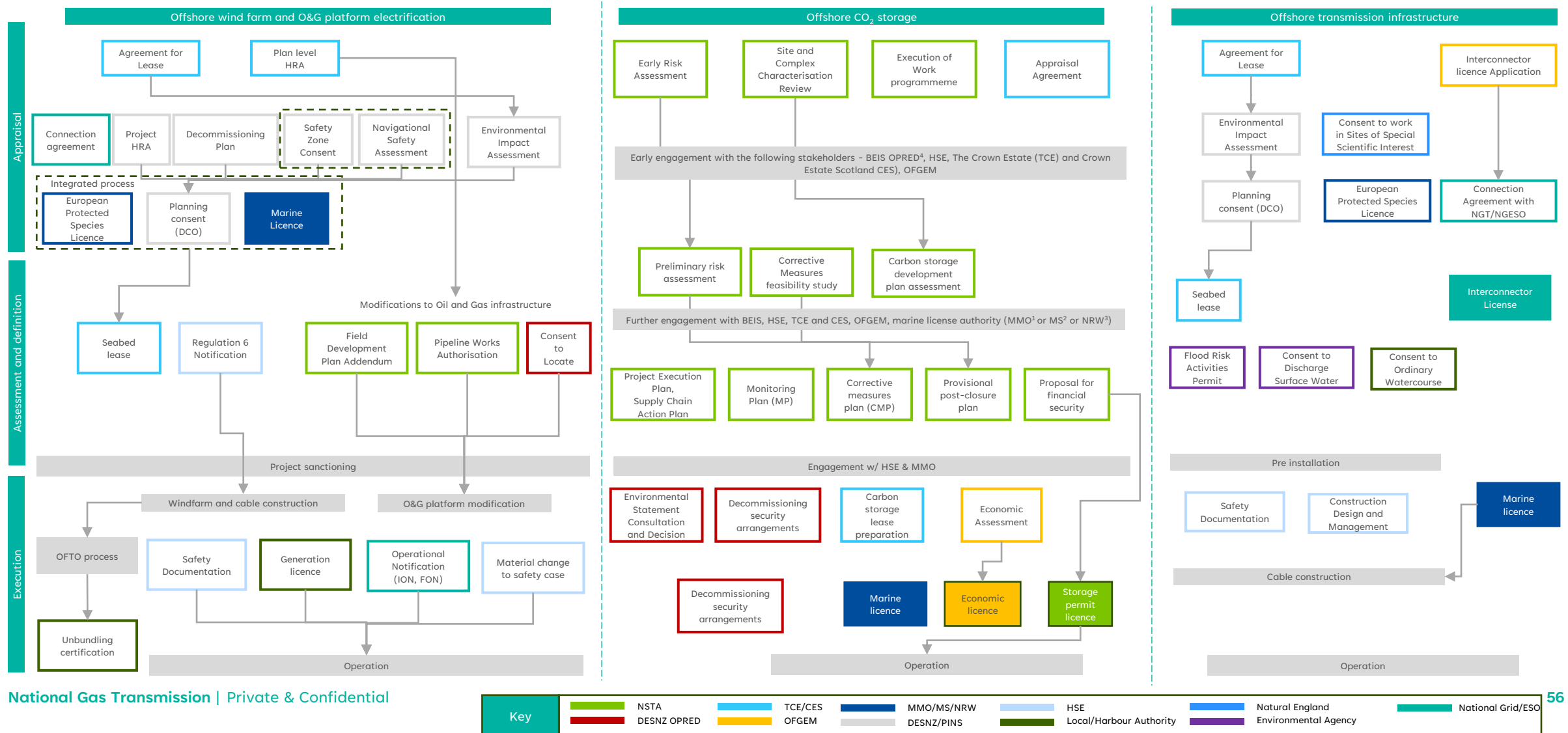
## Collaboration

- This also slows down progress to establish alignment with prospective EU partners currently developing offshore projects.



# Streamlining and reducing the complexity of the OEH regulatory landscape is a pre-requisite to their development

Indicative





# Opportunities to simplify and streamline regulations without compromising their purpose exists

Although there is ongoing work being undertaken by various organisations...



## Colocation Forum

- The Colocation Forum, led by The Crown Estate (TCE) is currently examining colocation between carbon storage facilities and wind farms, aiming to pre-empt operational hurdles.
- This entails navigating spatial constraints to prevent interference between critical infrastructure. For instance, how do we effectively manage a CO<sub>2</sub> site underneath a wind turbine?



## Government and Regulators Electrification Group (GREG)

- Efforts by GREG seek to improve the regulatory process with support from industry stakeholders.



## Technology advancements from Industry

- Technology advancements from industry players to mitigate operational challenges inherent in offshore system integration.



...there are still several streamlining and collaboration opportunities that can be identified

1

Clarity on the different regulatory boundaries governed by each stakeholder to ensure industry players have adequate guidance and information on appropriate licences and the relevant stakeholders.

2

Taking a phased approach to regulatory approvals can facilitate integration projects by allowing consent for different phases. This could include creating a regulatory sandbox or pathfinder to enable early-stage projects to progress.

3

Placing time stamps on all regulatory approval processes involved in developing offshore energy hubs so the developers can plan adequately.

4

Possibly harmonising regulatory regimes and frameworks to ensure consistent standards and approvals for OEH projects.

# The next stage of work would first align with existing working group and provide an independent overview of current state

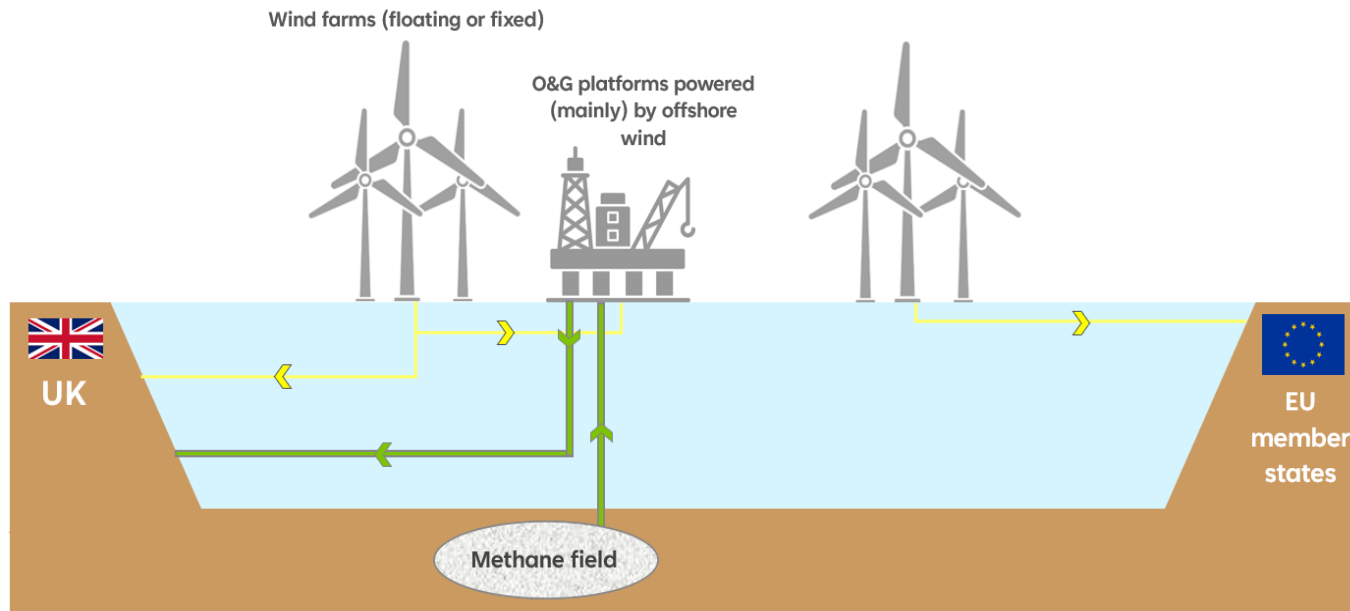
## Why work is needed on the offshore regulatory landscape

- 1** The current economic policy and regulations are hindering the integration of offshore wind with other offshore assets.
- 2** The current offshore infrastructure regulatory landscape is fragmented with many regulators, making it complex and slow.
- 3** Regulators are keen to collaborate and improve processes but are unclear on the exact boundaries of their respective regulatory remit.
- 4** Regulators highlighted that a mindset shift beyond focusing on sectoral interests is needed to ensure that long-term benefits are realised for GB consumers.

## What is needed to resolve these challenges

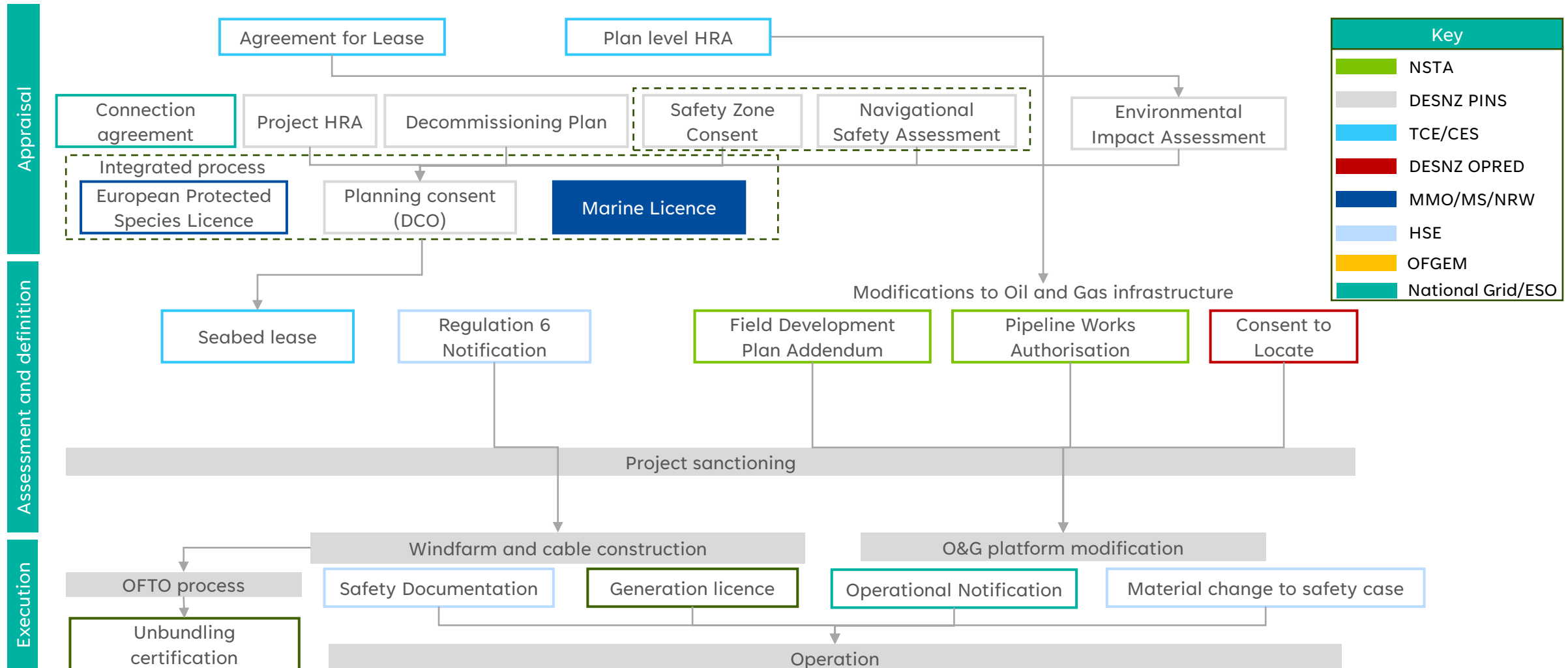
- 1 – Receive support from regulators** ✓  
Confirm the regulatory challenges highlighted and the work needed to solve some of these challenges.
- 2 – Engage policy makers for official buy-in**  
Engage DESNZ and the NESO to receive official buy-in to assess regulations through an independent perspective.
- 3 – Define ways of working with the GREG**  
Recognising that some work has been conducted by the Government and Regulators Electrification Group (GREG), it is important to define ways of working with the group.
- 4 – Independent regulatory deep-dive**  
As a first state, define current state and clearly outline each existing regulatory remit. Based on industry feedback, explore what regulatory processes can be streamlined without losing their initial intent and robustness. Test with regulators and industry and iterate.

# O&G electrification



# O&G electrification coupled with offshore wind requires permits for various stakeholders

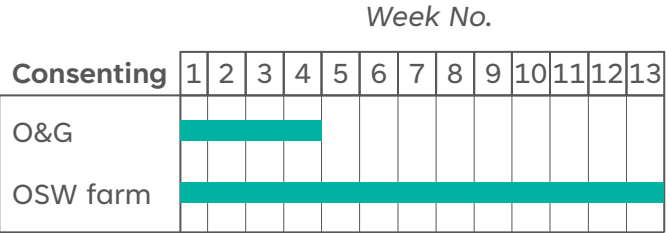
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# O&G electrification challenges revolve around approval timings, improved coordination and restrictive contracts

## Misalignment of OSW farm and O&G platform electrification timing

- Long windfarm consenting, planning and licensing timelines could make joint projects with O&G difficult. Also, various regulators for different parts risks one part being consented and the other, not.



- While licensing for platform electrification from the NSTA takes 28 days, consenting for an OSW farm from MMO can take up to 13 weeks.

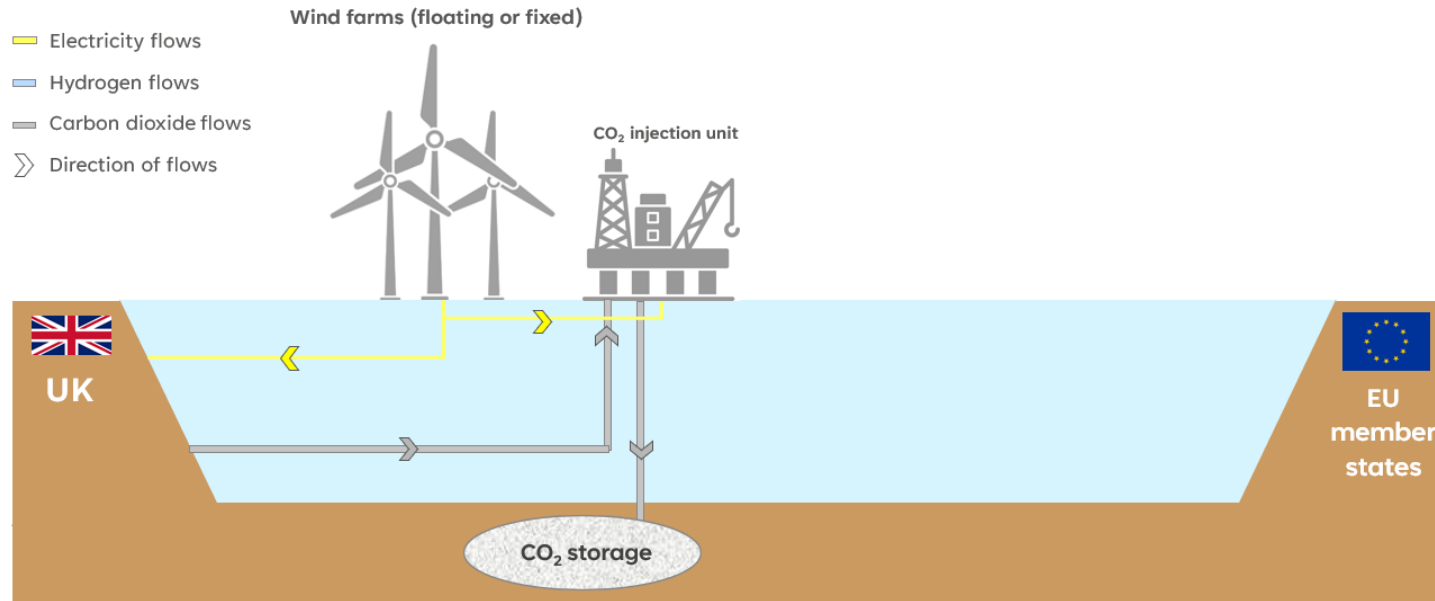
## Need for improved coordination of environmental assessments for O&G and OSW farm in the same areas

- Both offshore O&G platforms and offshore wind farms may cause similar disruption to marine ecosystems through noise pollution, habitat alteration, etc...
  - When developing integrated projects, evaluating the combined effects could lead to a more comprehensive assessment. This would speed up developments, reduce costs, as well as ensuring the publication of a more complete environmental impact assessment review.

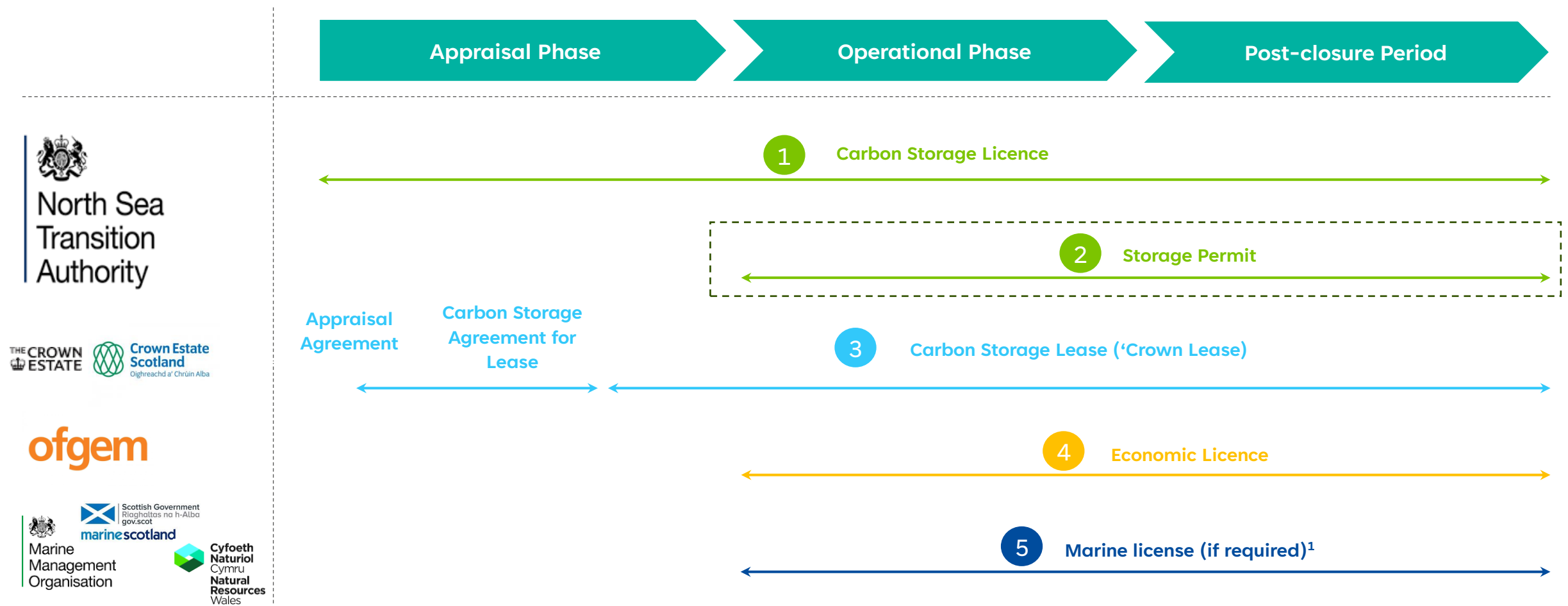
## Contract for Difference do not incentivise or directly block offshore energy infrastructure integration

- Offshore wind developers are currently not permitted to provide power both to the grid and to other offshore assets such as O&G platform under the Contract for Difference (CfD) Allocation Round 6. The government argues that this decision avoids a new cost burden on consumers.
  - However, this decision prevents the electrification and thus the decarbonisation of O&G activities in the UK which represented 10.9 MtCO<sub>2e</sub> emissions in 2023.
- This decision also prevent the integration of offshore energy infrastructure, which would potentially reduce curtailed power – ultimately reducing system costs (which are also passed through to consumers)

# Offshore CO<sub>2</sub> storage

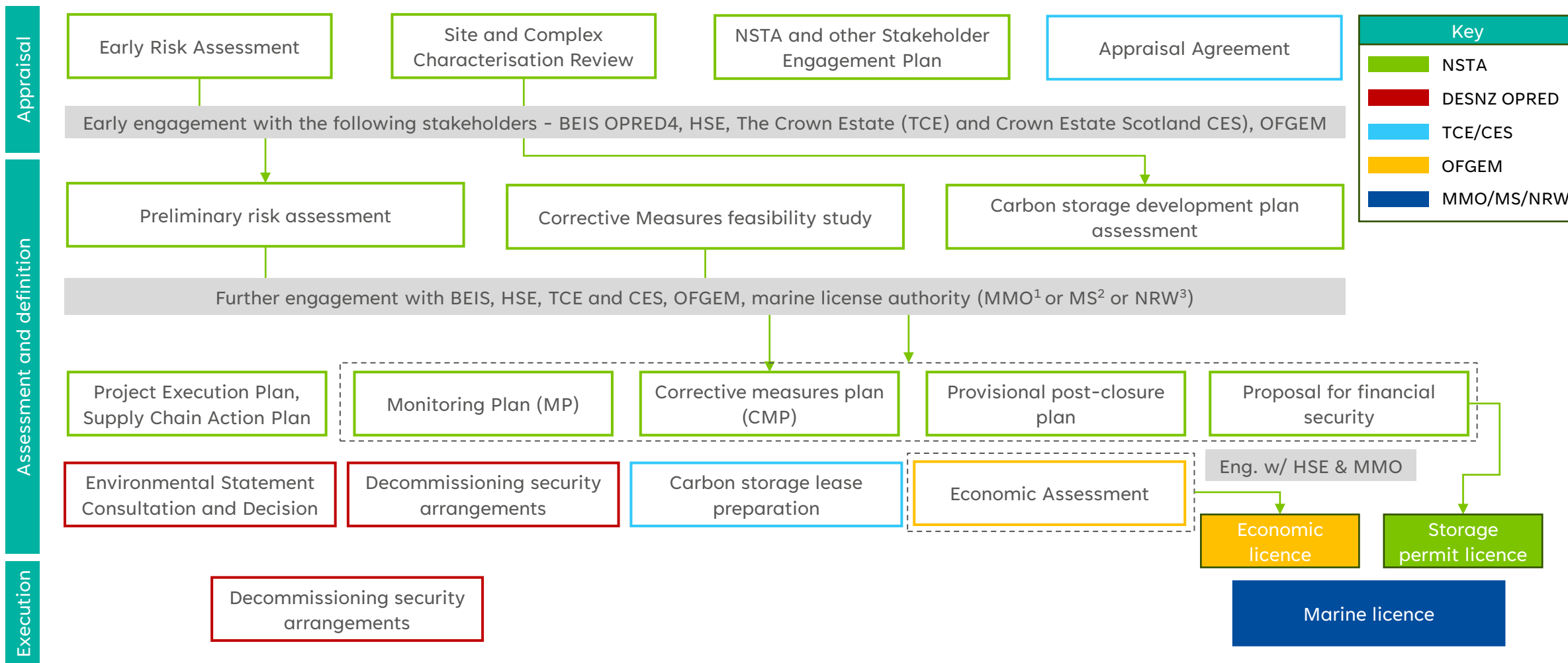


# Offshore CO<sub>2</sub> storage requires 5 main licences, issued across a few organisations



# Obtaining a storage permit requires phased engagements with the NSTA and other stakeholders

Indicative





# Offshore CO<sub>2</sub> storage developers encounter regulatory timing, licencing and approval issues

## Unclear timing for regulatory decisions

- Each of the elements of an offshore energy hub will require an Environmental Statement (ES) including the CO<sub>2</sub> storage component. However, the timing of regulatory decisions on ES can be uncertain which poses challenges for project developers planning.

## Lack of clarity on what some mandatory licences entail

- The Crown Estate has stated that drilling a borehole requires some form of consent. However, there is no information about what the consent process entails and who has the authority to grant it. This is because a new regime is set to be implemented. This create further uncertainty for developers.

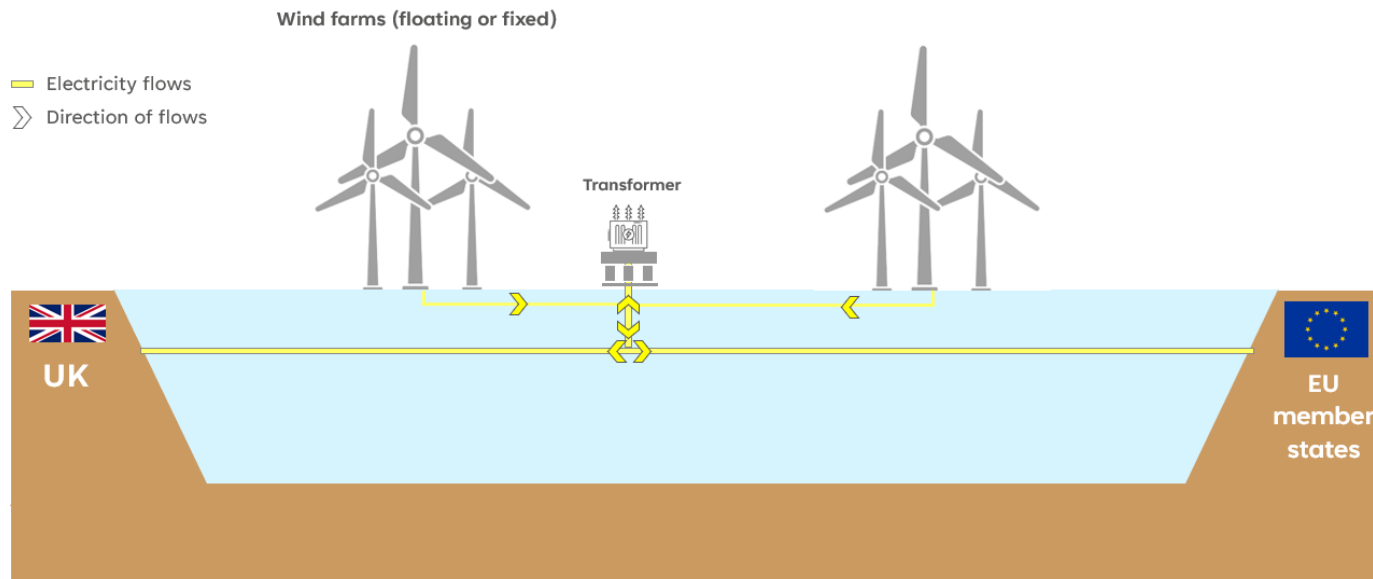
## Current regulation does not make provision for other types of business models

- The current economic licence provided by Ofgem only cover regulated CCS activities (operating under a regulated assess base (RAB) model).
- However, for a large scale, cross-border CCUS market to be developed, developers argue that that the economic licence needs to include fully commercial activity. This would be particularly important for offshore energy hubs where the CO<sub>2</sub> storage facility might be developed without specific customers in mind.

## Lack of clarity on approvals from all stakeholders required at each project phase

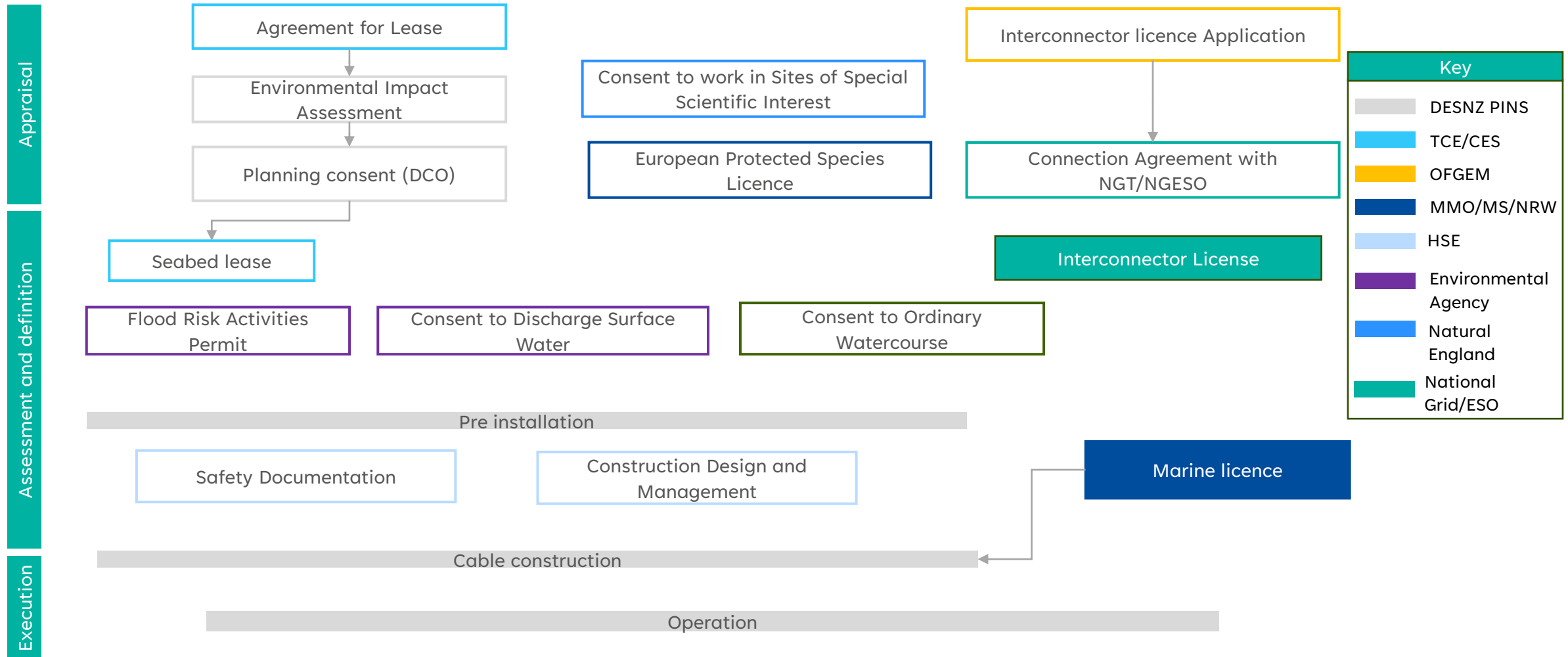
- To obtain a carbon storage licence, a work programme must be submitted to the NSTA for approval. This programme should outline any exploratory and appraisal activities that will be carried out. After receiving this licence, developers will still need another approval for any survey activity that interacts with the seabed, such as shallow sediment sampling. This approval must be obtained from TCE. The duplication of regulatory approvals increases the process complexity which increases cost and slows down development

# Multipurpose interconnectors



# Current regulatory process for interconnectors requires multiple consents required for execution

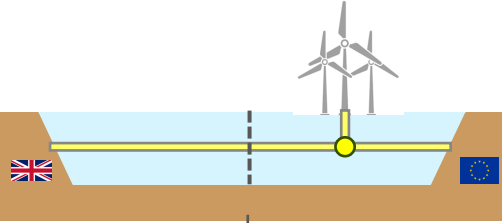
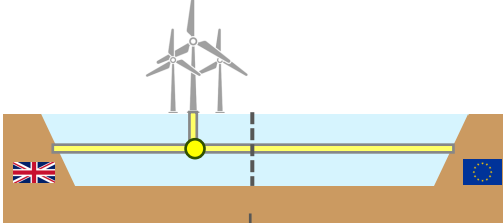
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# The economic licensing regime is still being discussed and will be complex due to costs and benefits sharing uncertainties

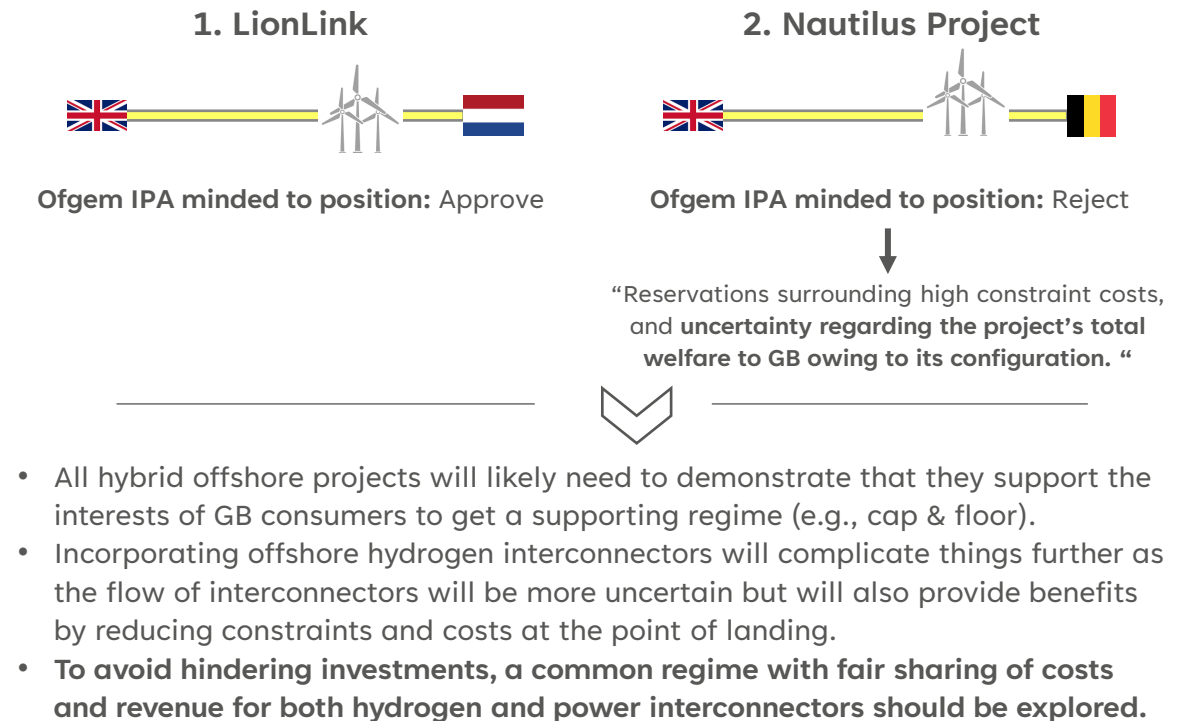
Ofgem is currently consulting on the type of a new type of interconnector license for **Offshore Hybrid Assets (OHAs)** - interconnectors connected to an offshore wind farm; A pilot program for this is in progress.

## Offshore Hybrid Assets (OHAs)

| Category 1 – Non-Standard Interconnectors   | Category 2 - Multi-purpose interconnectors  |
|---|---|
| <ul style="list-style-type: none"> <li>Non-GB connected offshore generator</li> <li>Conducting only interconnection activity in GB</li> </ul> | <ul style="list-style-type: none"> <li>GB connected offshore generator</li> <li>Conducting dual activity of both interconnection and offshore transmission in GB</li> </ul> |
|   |    |
| Standard Interconnector Licence (with amendments)   | Multipurpose Interconnector Licence   |

The Initial Project Assessment (IPA) pilot for OHAs has revealed **structural challenges in being awarded a cap and floor regime** which are set to be relevant consideration for Offshore Energy Hubs.

## Two projects were assessed in the IPA pilot



# In addition, the governance structure for offshore transmission operations in the UK is fragmented with multiple actors

In the UK, multiple stakeholders can be responsible for developing offshore electricity transmission assets. Unbundling of owner was created to incentivise competition. All stakeholders are regulated by Ofgem.



| Stakeholder Group                      | Key organisation   |
|--|--|
| 1 Offshore transmission Owners (OFTOs) | Transmission Capital Partners<br>Diamond Transmission Partners |
| 2 Electricity interconnector owners    | nationalgrid   |
| 3 Offshore grid owners                 | nationalgrid<br>Electricity Transmission                       |
| 4 Offshore grid operator               | SP ENERGY NETWORKS<br>ESO                                      |

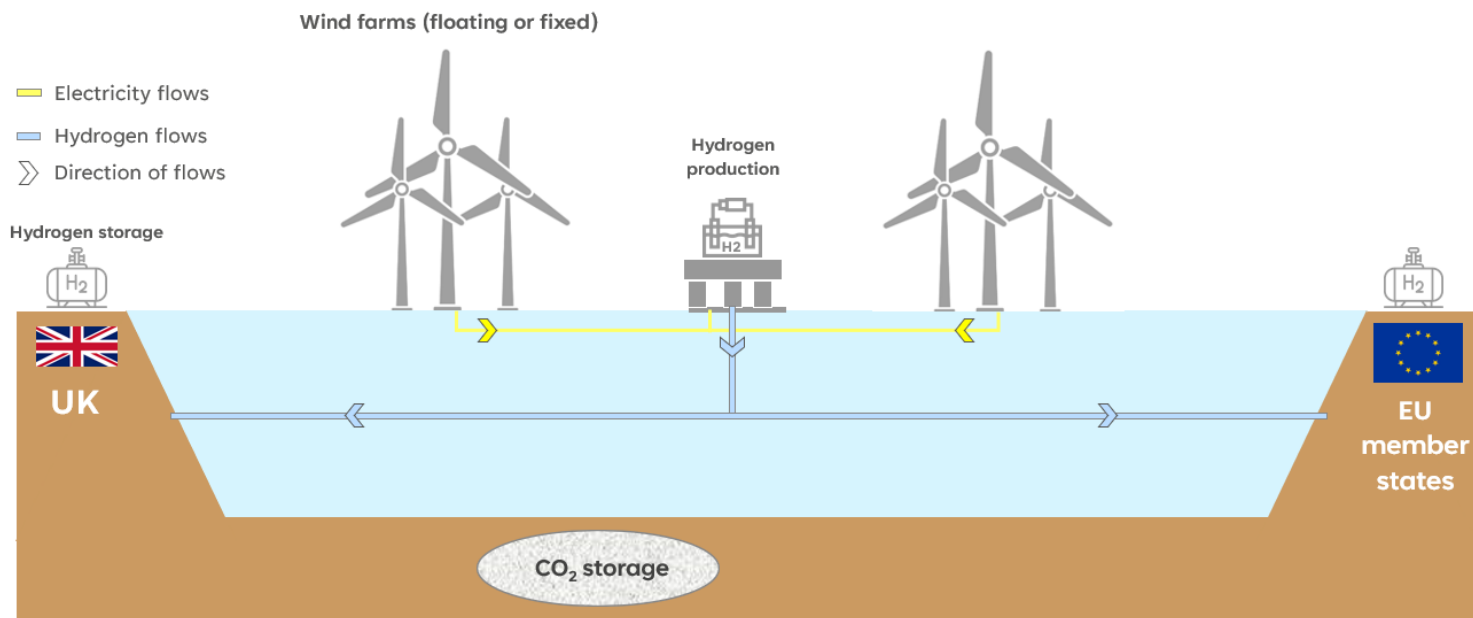
In The Netherlands, Tennet has being designated as The Netherlands’s offshore electricity transmission owner and operator, enabling greater coordination of offshore infrastructure development.



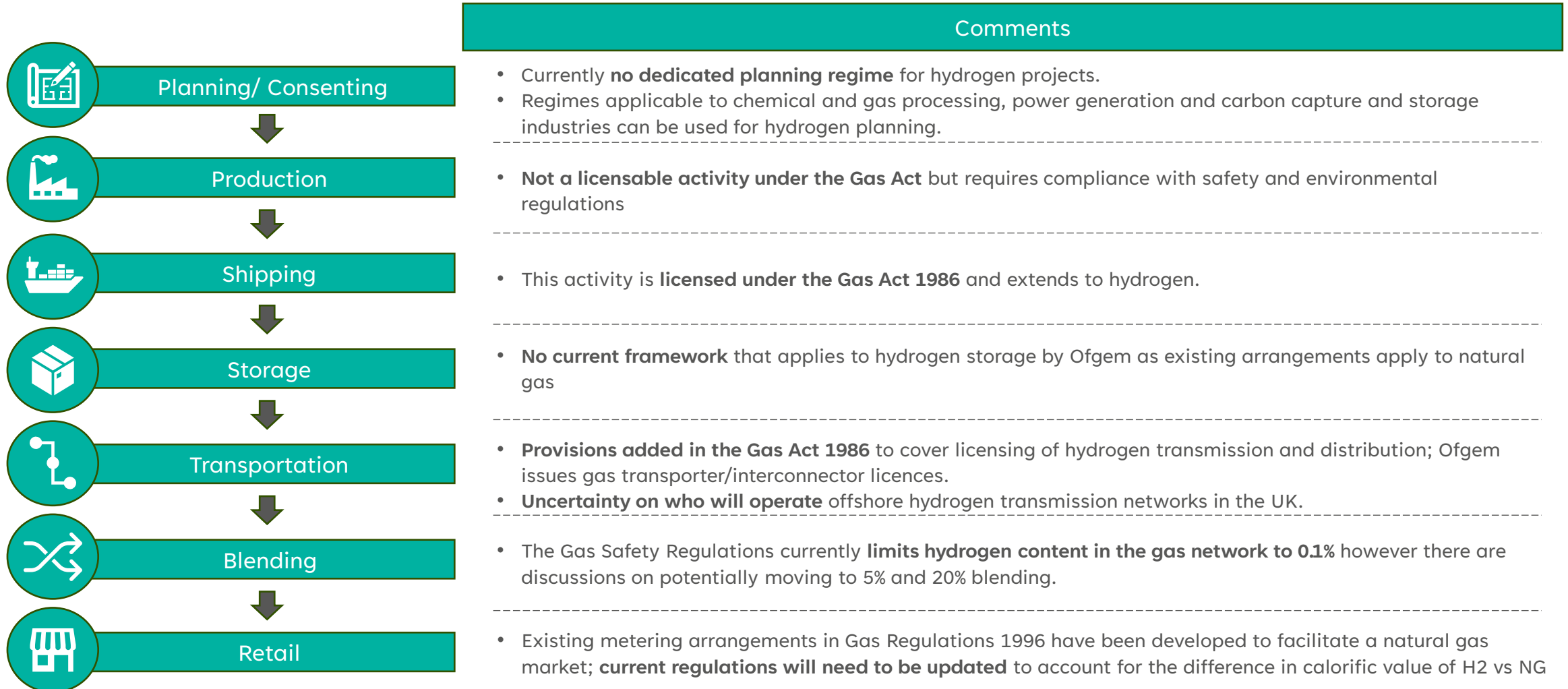
Gasunie, the Dutch gas transmission system operator, is expected to soon become the offshore hydrogen transmission operator and owner.

However, the UK has not yet addressed the issue of governance for offshore hydrogen infrastructure. It is essential to have clarity on future responsibilities to efficiently design Offshore Energy Hub.

# Offshore hydrogen production



# Given the nascent hydrogen landscape, licensing along value chain remains unclear



# Market Design gaps



# A coherent market design for offshore energy hub should provide transparency and clarity to stakeholders

## The market design for offshore energy hubs should:

- 1 Deliver clear market signals for offshore infrastructure investments
- 2 Provide additional revenue stream to reward system integration services provided to the system by offshore energy hubs market participants
- 3 Drive competitive and efficient dispatch behaviours of power and hydrogen offshore across bidding zones.
- 4 Ensure consumers directly benefit from offshore energy hubs development through more affordable and cleaner energy

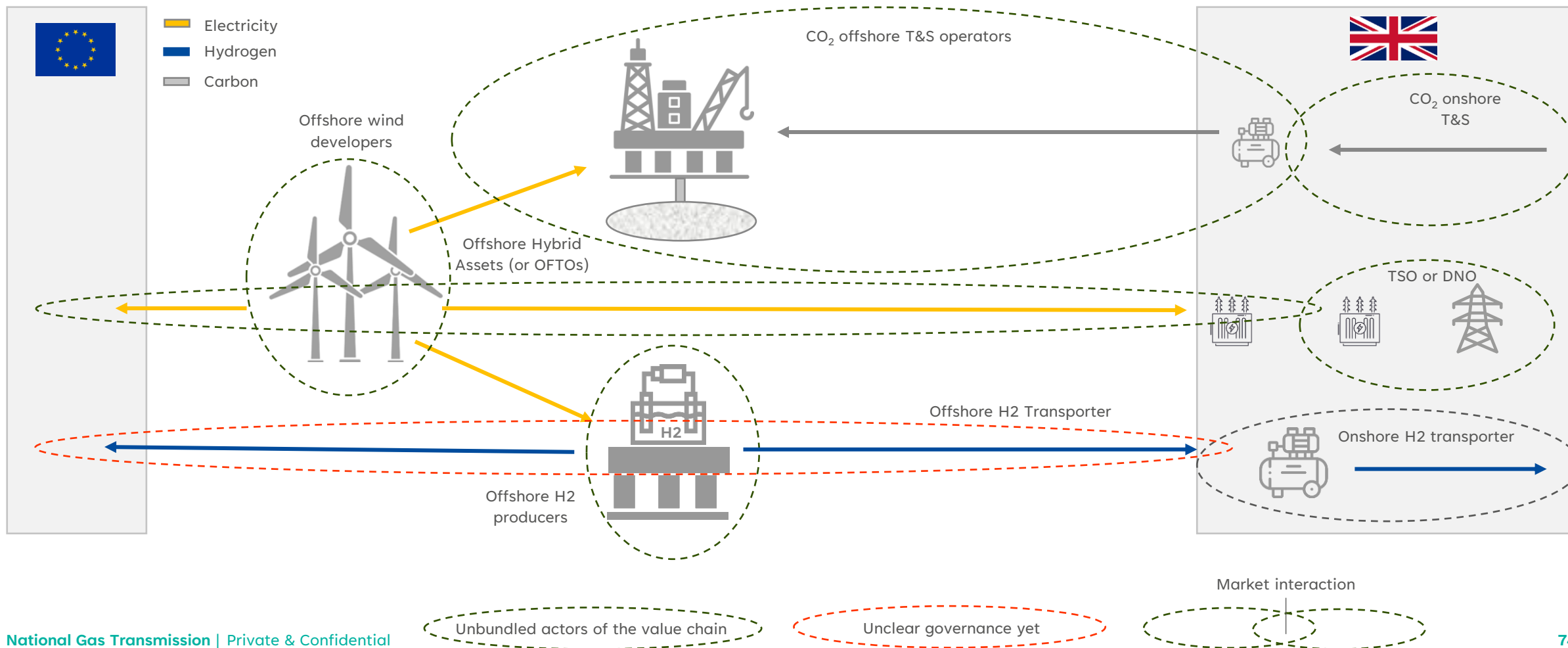
## Market design objectives

Efficient investment

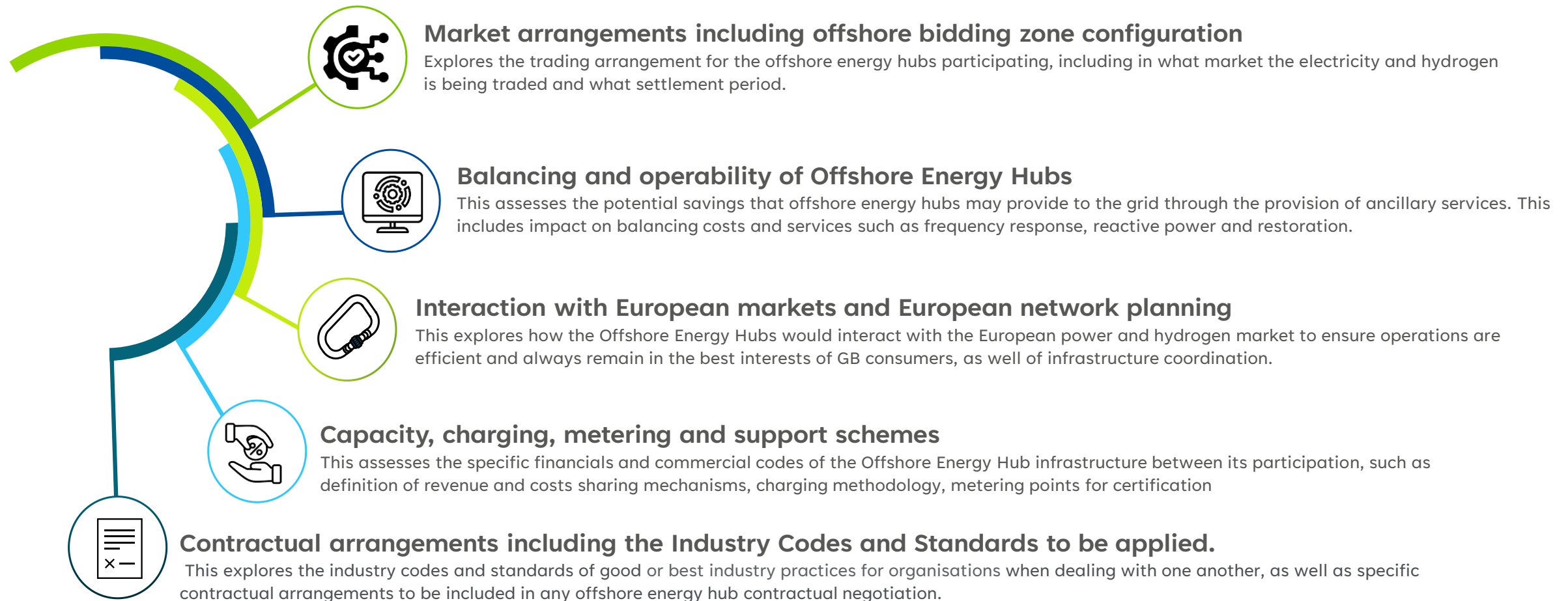
Efficient market behaviours

Value for Money

# Policy and regulations set the offshore value chain governance; market design should ensure efficient investment & behaviours



# To achieve market design objectives, the ESO, Ofgem, DESNZ and the industry should explore options in multiple areas

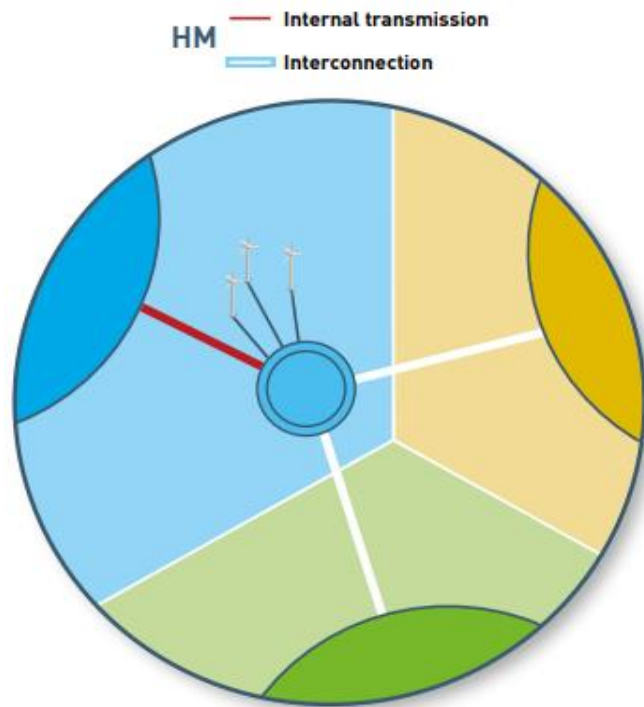




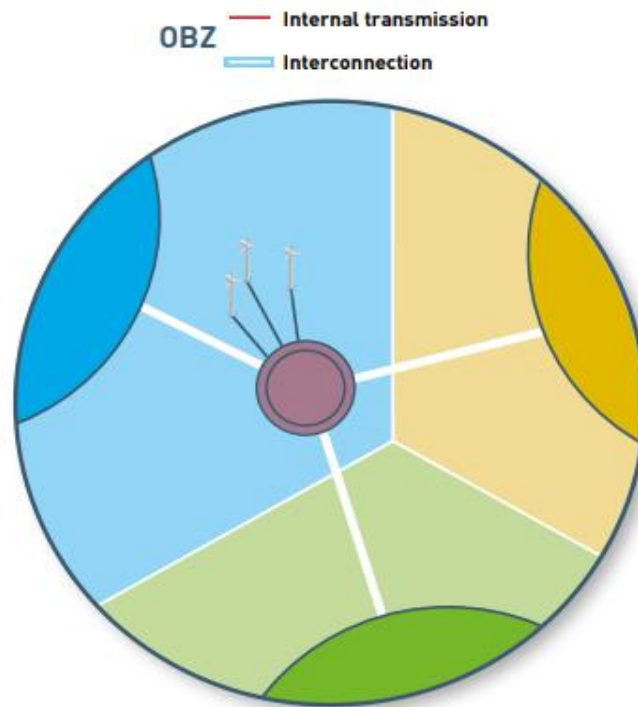
# Carefully designing market arrangement is key to ensure efficient offshore energy hub dispatch behaviours

Two offshore market setups are considered and explored at the European level

## 1. Home Market (HM)



## 2. Offshore Bidding Zone (OBZ)



## Key takeaways

### Home Market design

The offshore wind farm bids and dispatches to the UK national or zonal bidding zone and receives the corresponding electricity price. The cable between the hub and the UK is a hybrid asset, operated by an OFTOs whereas the cables between the hub and the other countries' bidding zone are cross-border interconnection.

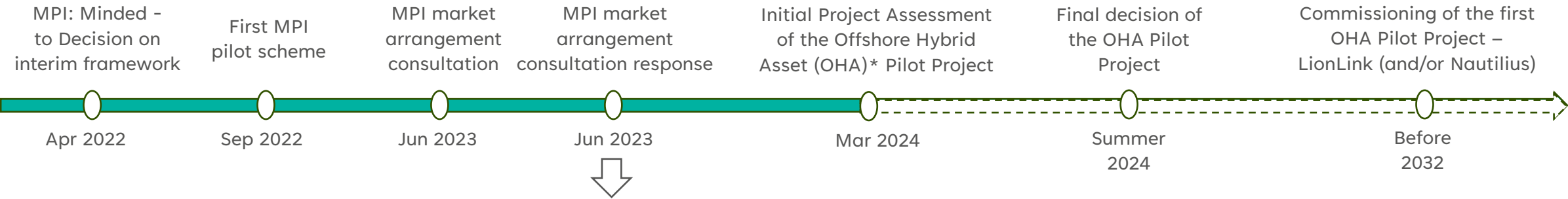
### Offshore Bidding Zone design

The hub forms a separate offshore bidding zone, in which the offshore wind farms submit bids and are dispatched. Via market coupling, the offshore generation is matched with onshore demand. The electricity price within the offshore bidding zone is the result of market coupling and is equal to the electricity price of the bidding zone connected by uncongested cross-border interconnection.



# OBZ with implicit trading market arrangements is currently the preferred options for multi-purpose interconnectors (MPI)

Ofgem has been consulting on market arrangements for multi-purpose interconnectors (interconnectors directly connected to offshore wind assets):





Based on preliminary engagement from Ofgem with stakeholders, **implicit trading arrangements was deemed better optimised** to delivering efficient markets and **OBZ was proposed as being the configuration more optimised** to trading under such arrangements.

1

| Options proposed to stakeholders |  |
|----------------------------------|--|
| Implicit trading & OBZ           | Combines the benefits of implicit trading (selling capacity on the interconnector and electricity together) and OBZ configuration (separate bidding zone created for the MPI and OSW farm(s)). |
| Implicit trading & HM            | Captures the benefits of implicit trading, but inefficiencies and challenges of HM configuration (trade as part of domestic market zone) remain, influencing the overall design.               |
| Explicit trading & OBZ           | A 'fallback arrangement' in the 'status quo' scenario where there is no implicit trading available. (post- EU-exit: capacity and electricity sold separately)                                  |
| Explicit trading & HM            | Operational complexities and inefficiencies of explicit trading are potentially exacerbated under the OBZ configuration.   |



# More work is required to conclude whether this market arrangement is well suited when including offshore offtakers

|  <b>Price risks</b>  |   |  <b>Volume risks</b>  |  |
|---|---|--|--|
| Developer risks   | Offtaker risks  | Developer risks  | Offtaker risks   |
| <ul style="list-style-type: none"> <li>Connectivity to bidding zone in different countries might <b>complicate the establishment of subsidy regimes</b> (e.g., Contract for Difference (CfDs)), as these are decided at a national level. It also might <b>complicate the establishment of a PPA</b>, if physical flows to a bidding zone in a specific contractual requirement.</li> </ul> | <ul style="list-style-type: none"> <li>Although an offshore off-taker may have access to direct co-location and multiple bidding zones, it <b>might not benefit from it if actors prefer to sign CfD contracts</b> (seen as potentially less risky).</li> <li>With developers having access to multiple PPA markets, demand competition might result in <b>increased PPA contract price</b>.</li> </ul> | <ul style="list-style-type: none"> <li>Competition through market coupling algorithms and onshore capacity constraints may <b>limit the amount of electricity the developer can sell</b>, reducing market access and potential revenue.</li> <li>Sensitivity to reductions in grid capacity availability can lead to <b>severe limitations on transmission</b>, causing operational inefficiencies.</li> </ul> | <ul style="list-style-type: none"> <li>The offshore offtaker faces <b>inconsistent electricity supply</b> due to interconnector and onshore grid competition, as well as reductions in grid capacity availability.</li> <li>These volume risks lead to <b>potential production disruptions, increased operational costs, difficulty in meeting hydrogen demand</b>, and challenges in fulfilling supply agreements.</li> </ul> |

## Opportunity to reduce risks

### Reducing price risk:

- A Cross-border subsidy regime between the UK and European countries might need to be established to enable development of OEHs
- Appropriate regulatory designs enabling cross-zonal PPAs to be considered as a physical PPA.

### Reducing volume risk:

- Offshore wind and interconnector cannot both benefit from a non-integrated, competing subsidy regime. Instead, fully merchant interconnectors should be considered.



# The impact of OEH on system balancing is a key element to consider to ensuring grid stability and reliability



## System constraints and renewable energy curtailment

**Constraints:** Given the finite capacity of the transmission system, actions are employed to ensure it is adequately balanced at each point in time. Balancing actions often take the form of payments to generators such as OSW farm developers. Transmission system constraints can occur in two situations:

- **Import:** when energy demand cannot be met by localised generation and the flow into the relevant area is limited by circuit capacity
- **Export:** happens when supply in the area is more than localised demand and outflow is limited by circuit capacity

**Development of offshore assets could increase constraint costs or require further network reinforcements, without the integration of H<sub>2</sub>**

**Curtailment** refers to an activity carried out to reduce output from a generation unit connected to the system, thus improving operational balancing. On the transmission grid, flexible solutions such as demand-side response, storage, interconnectors, etc., are often used to avoid curtailment

Thus, OEHs could help reduce curtailment of renewable energy supply thanks to the flexibility they provide through interconnectors and co-located H<sub>2</sub> electrolysis



## Grid ancillary services

System operators procure a range of services to ensure optimal stability and operability of the grid. Three of such services are discussed below:

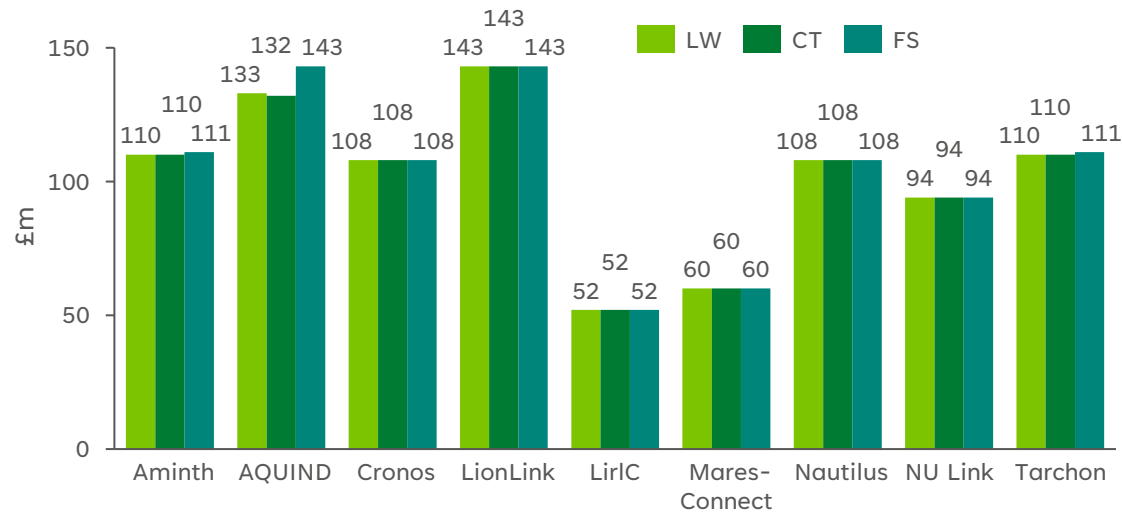
- **Frequency response/reserve:** services necessary to ensure that UK system frequency remains at 50Hz, the standard for all UK appliances.
- **Reactive power support:** services that are used to maintain the voltage on the transmission system within a given range
- **Restoration:** services that can be procured to ensure system restoration in the event of a partial or total shutdown

**OEHs are expected to use Voltage Source Converter (VSC) technology which allows for the provision of reactive power, thereby assisting in frequency and voltage control**



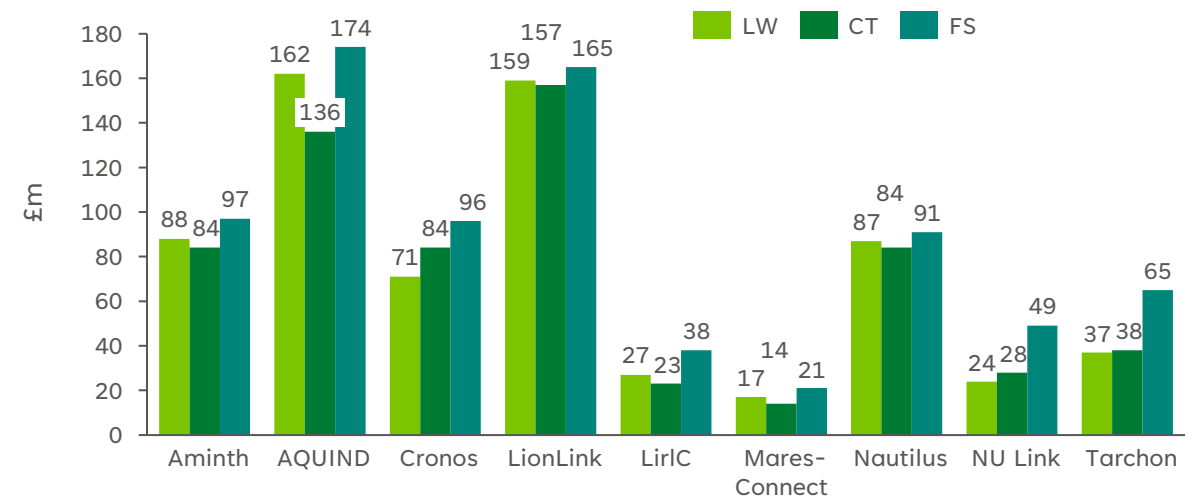
# OHAs are set to provide extensive cost savings through ancillary services as expected

Reactive power savings of each interconnector and OHAs for the First Additional case, present value, 25 years, real 2022, £m.



- ESO estimates that OHAs could deliver between £108m–£143m in savings over 25 years, stemming from reactive support benefits that assume the presence of Voltage Source Converter (VSC) based technology.
- **However, interconnectors are often located on the periphery of the network which may not be the optimal location for providing these reactive power services. Further work is needed on the best locations for OHAs**

Frequency Response savings for all interconnectors and OHAs for First Additional case, present value 25-year, real 2022, £m.



- The ESO roughly estimates that OHAs, LionLink and Nautilus could provide frequency response savings of up to £174m over the period.
- **To ensure these savings are realised, technical, regulatory and commercial challenges must be overcome. These include ensuring effective energy transfer settlement and adequate alignment on frequency rules with other connected systems.**

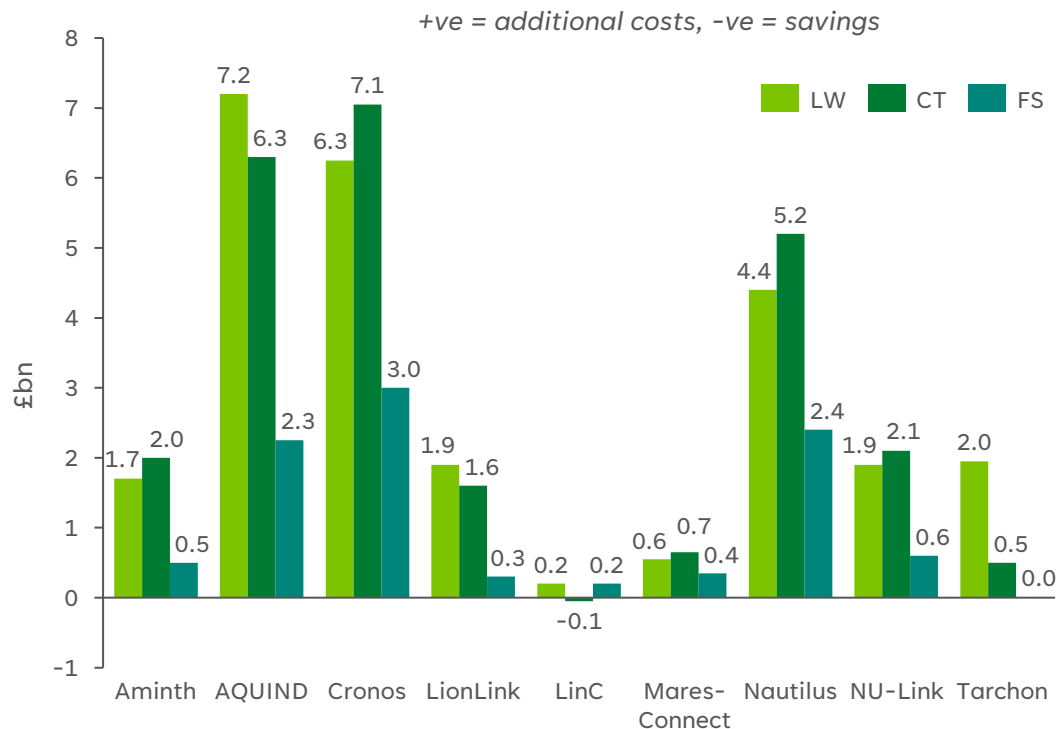




# However, OHAs could increase network constraints costs across the network depending on their locations

## OHAs could increase balancing costs without H<sub>2</sub> integration

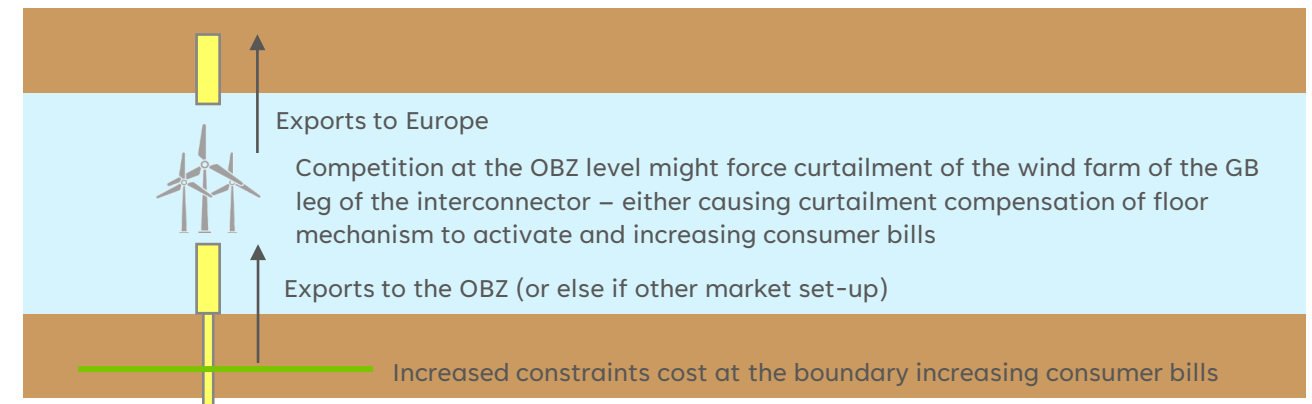
Change in constraint costs due to the addition of each interconnector and OHA for the First Additional case, PV, 25 years, real 2022, £bn.



## Key takeaways

- The modelling conducted by the ESO shows that combined multi-purpose interconnectors (without demand flexibility provided by offshore energy hubs) are likely to increase balancing costs by up to £26 billion over the 25-year modelled. The constraint costs increase on most interconnectors are primarily due to the volume of electricity generation in GB that would be exported from North to South to respond to demand signal for exports to Europe at the interconnector level.
- Any interconnector or OHA that connects in the Midlands or southern England and that is exporting for most of the time is likely to lead to increased constraint costs as more balancing actions will need to be taken to relieve constraints across various boundaries.

### High-level schematic of potential challenges:



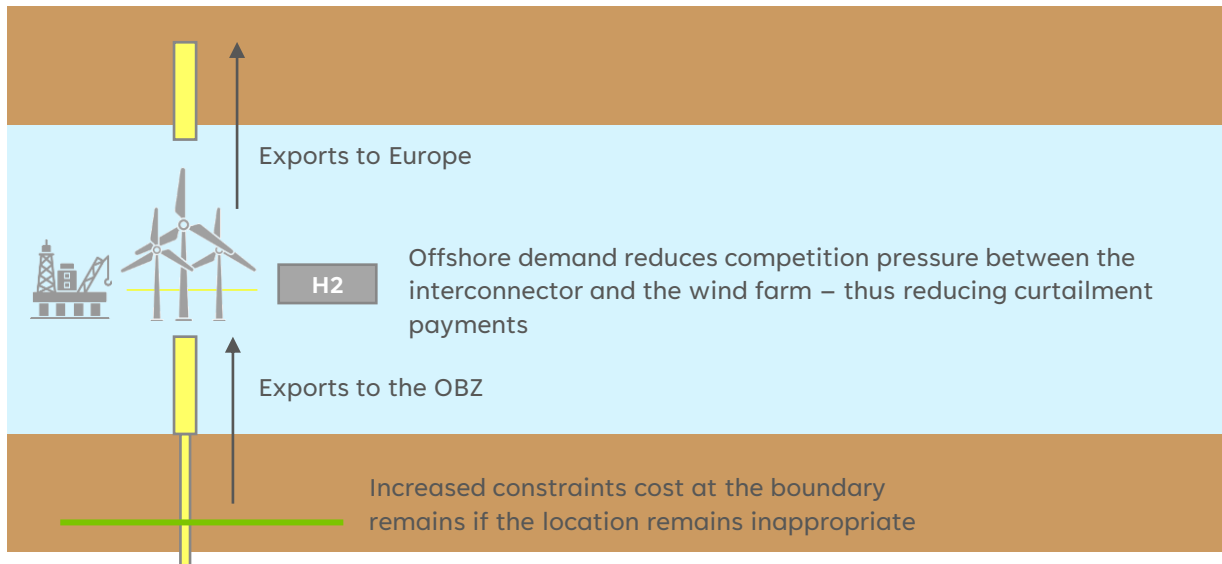


# In addition, there could be flexibility gains from other parts of the offshore energy hubs, besides interconnectors

## Offshore bidding zone flexibility

**Export constraints definition:** The generation in the area is not offset by the localised demand and the flow on the circuits out of the area is limited by the capacity of the circuits.

**Offshore Energy Hubs contribution:** By creating demand at the OBZ level, Offshore Energy Hubs reduce the risk of export constraint at the OBZ level, hence reducing curtailment payments.



## Key takeaways

- Offshore energy hubs could significantly help reduce network constraints by reducing curtailment through offshore hydrogen production. A full network load analysis should be performed in this set-up to better understand the full benefits.
- However, appropriate contractual arrangements and revenue-sharing mechanisms are required for this flexibility to be rewarded and incentivise offshore hydrogen investments.
- Most of the system flexibility is provided by the offshore H<sub>2</sub> developer, who could fluctuate its outputs based on demand signals. However, there might be little incentives for the hydrogen developers to do so under given the high CAPEX and risks associated with offshore infrastructure investments.
- The flexibility provided by the offshore hydrogen developer in the OBZ needs to be appropriately rewarded by the ESO. This could be done through the BM or, better, through a fixed stable long-term capacity payment to provide investor revenue visibility and reduce the cost of capital.

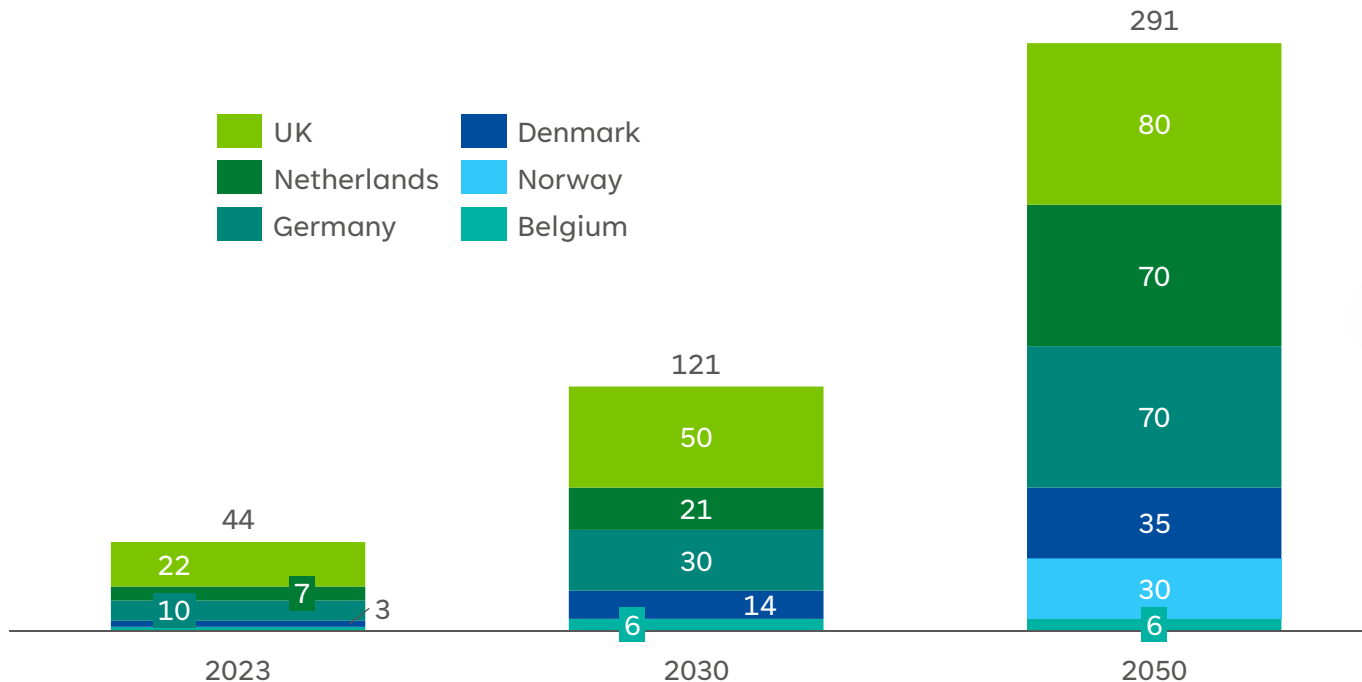


# North Sea countries have a combined target for offshore wind of over 290 GW by 2050

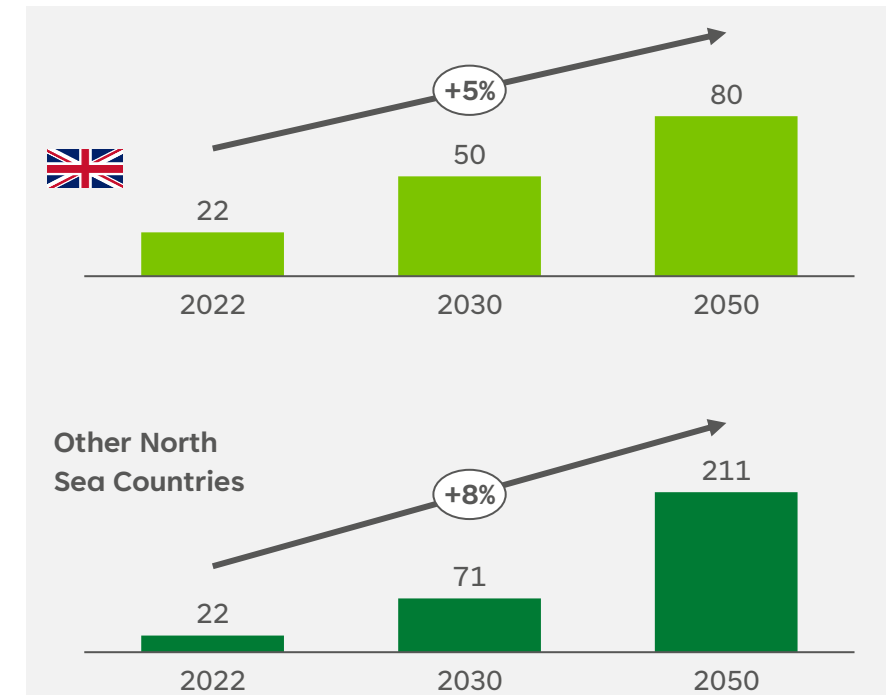
2050 offshore wind targets of the UK and other North sea countries expected to see a more than 10X increase from today's installed capacity...

...demanding an accelerated build out for all North Sea countries.

Total offshore wind installed capacity for 2023 and 2050 by North Sea country, GW



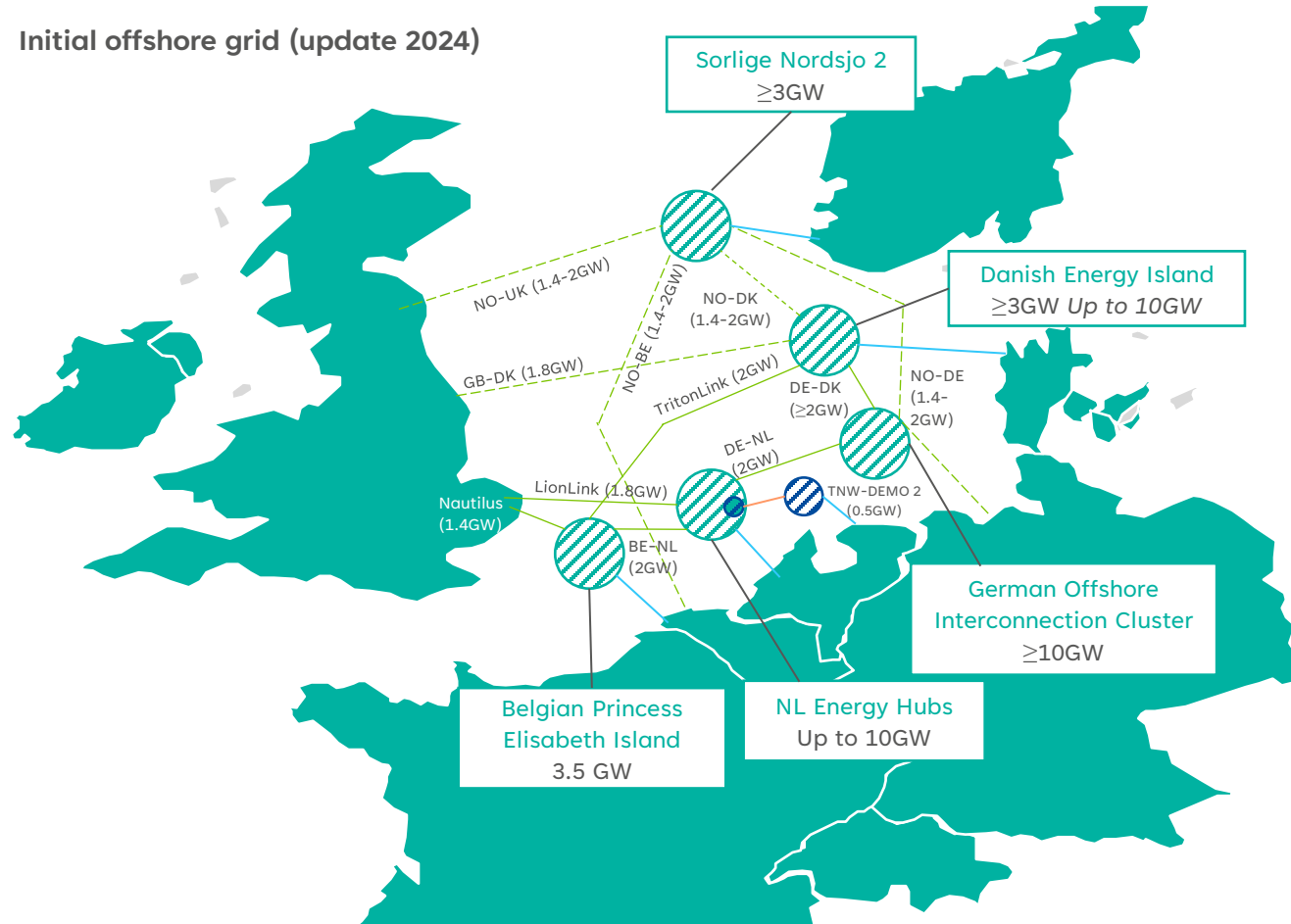
Offshore wind capacity for 2022, 2030 and 2050, GW





# An offshore grid has been recommended by all North Sea TSOs as the most efficient way to meet offshore wind targets

Initial offshore grid (update 2024)



## Key

- Offshore wind area with radial connections, hybrid interconnectors and energy hubs
- Offshore hydrogen demonstration project
- Hydrogen and electricity hub
- Connection to shore
- MOU<sup>1</sup> for interconnectors
- MOU for investigation of different options
- Hydrogen pipeline

Several projects, either in construction or assessment phases are expected to form the foundation for an offshore grid in the North Sea.

These projects include:

1. Energy hubs such as Princess Elisabeth Island (BE), Danish Energy Island, NL Energy Hub, German Offshore Interconnection Cluster
2. Hybrid interconnectors like Nautilus (UK+BE), TritonLink (BE+DE), LionLink
3. Hydrogen pipeline such as the TNW-Demo 2 (NL) located in the Dutch EEZ



# The UK also has reiterated its willingness to collaborate with EU and North Seas countries on offshore system integration

“

Germany and the UK are close partners in fostering the energy transition, renewable energy, and hydrogen development...We have agreed on a feasibility study for H<sub>2</sub> exports from the UK to Germany... we will cooperate to produce renewable energy from the North Sea, including offshore wind and renewable hydrogen to secure our off-shore critical infrastructure.



*UK Prime Minister, Rishi Sunak, 24/04/2024*

“

This fulfils commitments in the UK-EU Trade and Cooperation Agreement (TCA), enabling the UK to work with NSEC members to develop renewables projects in the North Seas - specifically projects linking electricity interconnectors and windfarms...

*DESNZ (then BEIS), 18/12/2022*

“

The two countries (Norway and UK) will "continue their close collaboration for the longer-term sustainable and efficient utilisation of the North Sea, co-operate on green and low-emissions technology such as offshore wind, offshore grid networks and the potential of hybrid projects"

*Norwegian Prime minister, Jonas Gahr Støre, 13/05/2022*

“

The development of renewables in the North Seas is critical for accelerating our clean transition and boosting energy security for the UK and our European neighbours.

*UK Minister of State for Energy and Climate, Graham Stuart, 18/12/2022*

“

The Memorandum signed today provides the NSEC members and the UK with a basis to cooperate on offshore energy. Given the significant potential of offshore renewable energy in the North Seas, this cooperation is important to help achieve our joint renewable offshore ambitions.

*EU Energy Commissioner, Kadri Simson, 18/12/2022*



# However, divergence between the UK and European policy makers could complicate cross-border interactions

## Context



Post-Brexit, the UK and EU signed a free trade agreement, **EU–UK Trade and Cooperation Agreement (TCA)** to govern relationship between the two governments.

While the TCA ensures some broad alignment of rules, **differences in market design elements and divergence in organisation** makes the business case for an interconnected energy hub more difficult.

## 1 Trading arrangements

- Post TCA, the UK lost access to implicit day-ahead and intraday market coupling arrangement on GB electricity interconnectors, meaning that capacity on interconnectors will no longer be procured together with electricity. If unresolved, the less efficient ‘explicit’ trading arrangement **could complicate trading from the OEH to either the EU or the UK. Current EU-UK agreements lean towards the Multi-Region Loose Volume Coupling (MRLVC) market coupling method**, which is a challenging solution from a CBA perspective. **How can the two governments enable market coupling?**
- Also, for short-term capacity calculation, the EU uses flow-based capacity calculation, whereas GB uses the net transfer capacity (NTC) calculation. With this difference in capacity allocation calculations, there is a **lack of clarity on how much capacity would be available for trade. Is there an alternative arrangement that could work for both markets?**

## 2 Potential EU bidding zone splits

- Ongoing work in the EU could see a **change in configuration of current bidding zone, which will impact OEH assets**. A close watch on the outcome of the EU bidding zone review is therefore important **to identify and resolve any potential challenges early on**.

## 3 Carbon border adjustment mechanisms (CBAMs)

- The EU CBAM is levying a tax equal to the difference in carbon prices on imports including electricity. This presents **a significant challenge for North Sea investment** leading to both potentially **serious administrative and tariff barriers for clean electricity trading between GB and the EU**.



# Supplementary agreements and combined resources from relevant parties are required to realise this collaboration

## Agree on cost and benefit sharing rules in OBZs

- Establishing fair mechanisms for sharing costs and revenues for OHAs and OBZs is crucial for commercial parties and national authorities involved in offshore energy projects.
- Agreeing on these rules will ensure clarity and avoid potential project deadlocks.

## Linking national and regional trading schemes

- Discussions on linking the EU and UK Emissions Trading Systems (ETS) is essential in preventing any negative impact of the CBAM on clean electricity trading after 2026.
- In the short term, the UK and EU should collaborate on practical improvements to the EU CBAM design, e.g., developing an improved methodology for assessing carbon content of UK electricity imports by recognizing the UK ETS already paid domestically.

## Setting up new common funding mechanisms

- In addition to dedicated funds provided by the EU and national institutions, establishing a dedicated fund at the sea basin level for the implementation of the initial offshore grid in the North Seas is crucial.
- This will facilitate the development of OEH and promote collaboration among North Sea countries.

## Creation of EU-UK hydrogen rules

- Given that the (TCA) does not address hydrogen, establishing common market rules is essential. This includes rules for certificate trading and addressing questions related to oversight and governance.
- Creating clear regulations will facilitate the development of a robust EU-UK hydrogen market.

### Key Takeaways

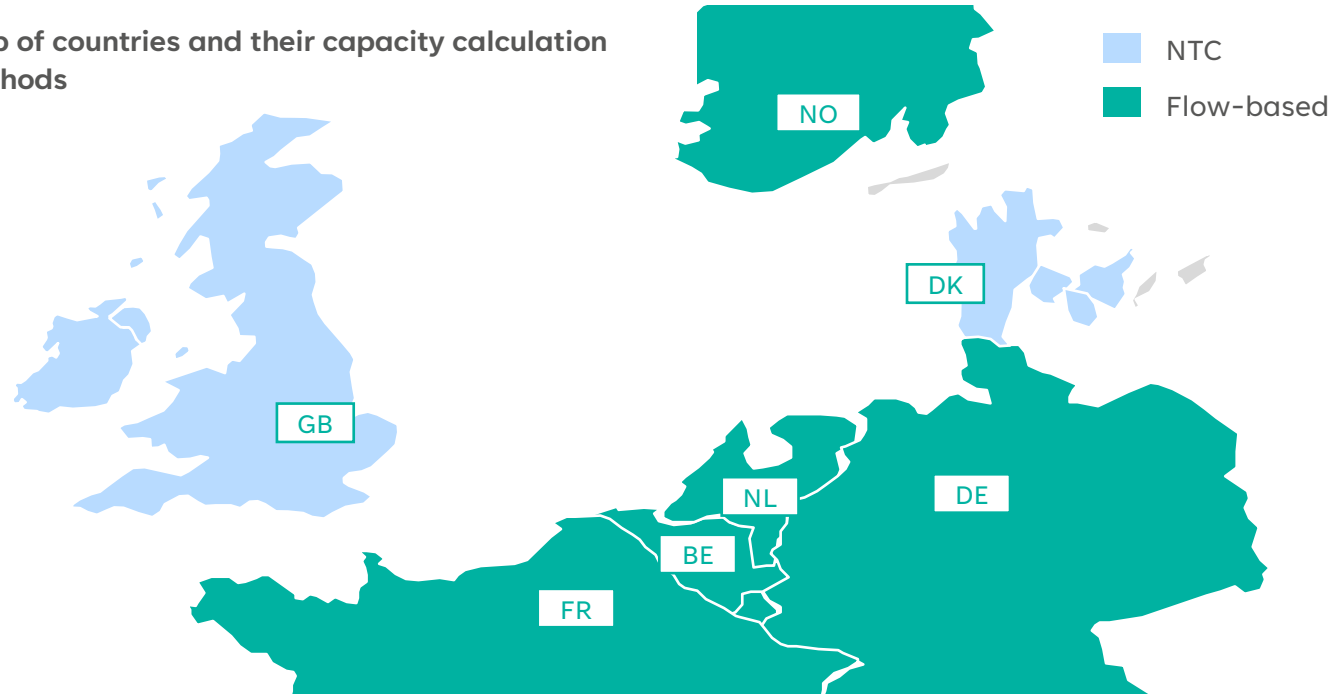
- For the UK, enhanced collaboration with the EU is essential, despite potential challenges in decoupling. Diplomatic efforts must reconcile conflicting interests and ensure that policy decisions foster collaboration with EU countries.
- A suitable revenue-sharing mechanism must also be developed to ensure that all connected countries' consumers benefit from offshore integration.
- The UK Transmission System Operators for both electricity and gas must establish working groups with their EU counterparts to facilitate collaboration. Additionally, funding this form of network innovation, in which new collaborations and interactions are formulated, is vital to increasing energy security in Europe.





# Capacity – In an OEH context, UK interconnectors may need to be adapted to fit EU flow-based target model

Map of countries and their capacity calculation methods



Two approaches to **capacity allocation and calculations**.

- The **net transfer capacity (NTC)** process calculates the maximum import/export capacities that an interconnector can release to the market; it is calculated independently for each flow direction and time.
- **Flow-based (FB)** means that capacity is calculated and allocated considering the meshed nature of the transmission network and all possible paths through which electricity is flowing in it. It is preferable for short-term capacity calculation in highly meshed and highly interdependent grids.

## Key takeaways

To facilitate the commercial exchange of electricity across zonal borders, available capacities are calculated in a coordinated way.

- Coordination regarding capacity calculation will be required among all the relevant system operators, particularly in cases when one region applies the FB and the other NTC based calculations.
- Currently, the UK interconnectors operate on the NTC-based and the EU is moving towards a flow-based target model. With the OEH concepts and North Sea integration demanding increasing connectivity and interdependency, this would warrant a common capacity calculation method.

## H<sub>2</sub> considerations

- Would hydrogen interconnectors follow a similar methodology to gas interconnectors (daily trading), or could zonal capacity allocation also play a role given the more intermittent nature of future hydrogen supply?
- Also, broad alignment will be required for the hydrogen markets; will connected markets require a single trading settlement period?





# Support schemes – CfDs remain the preferred compensation approach, given the complex nature of revenue re-distribution

For GB offshore assets, there are two main approaches to compensate developers for projected lower revenues that could be earned under an OBZ market configuration

## Redistribution of congestion revenues and income

Two methods could be taken to share congestion revenues –

- Use of preferential Financial Transmission Rights (FTRs) to effect ex-ante redistribution. FTRs occur which market participants are compensated for any price risks of delivering energy to the transmission system.
- Ex-post redistribution of revenues

However, this still impacts the risk profile of such OSW project as revenues are not forecasted easily, making new project less bankable.

## Amending Contracts for Differences scheme

Various amendments to the current CfD scheme have been proposed including:

- Establishing an OBZ reference price and avoiding subsidisation of electricity sold in another country. This other country would be responsible for signing its own support scheme with the wind farm (see next slide).
- Capacity-based CfD, enabling offshore wind farm to sign an additional PPA with an offshore offtaker to cover risks.
- Aligning the duration of the project life of an OHA (25-30 years) and the 15-year CfD duration.

However, this still adds additional complexity to such OSW project.

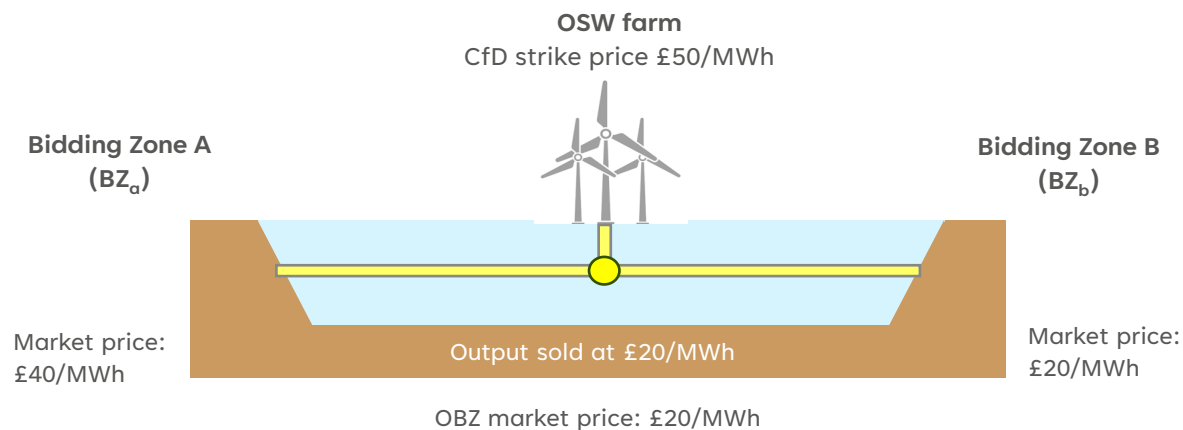
## Key takeaways

- The current market decision is skewed towards amending the CfD scheme, citing issues for redistributing congestion revenues such as:
  - **Increased complexity:** The use of preferential FTRs has been highlighted as being too complicated and to the detriment of market participants.
  - **Conflict with other regulation:** Ex-post distribution options suffering shortcomings given its incompatibility with electricity regulation that restricts the use of congestion revenue from interconnectors to only specific purposes.
- While the CfD amendment remains the preferred choice, challenges still exist on the eligibility of participants under current scheme rules with its restrictive nature on OSW farm supplying electricity to O&G platforms and loss of revenue for OSW farm in the OBZ scenario when importing.
- DESNZ on-going Review of Electricity Market Arrangement (REMA) is assessing amendments to the CfD regime in the UK, with Deemed CfD and capacity-based CfD considered. However, OBZ are not in scope of REMA and CfD design choice is considered without OBZ in mind.



# Support schemes – The OBZ market price should be taken as the CfD reference price and formed by implicit price coupling

Without taking the OBZ market price as the CfD reference price, OSW farm would be subject to significant price risk as OBZ will set on the market price of the lowest neighbouring bidding zone



## Approach 1: CfD paid with reference to BZ<sub>a</sub>

- CfD top-up is calculated as £50 (strike price) - £40 (BZ<sub>a</sub> price) = £10/MWh
- But OSW farm will not have received BZ<sub>a</sub> market price and will have instead been paid the OBZ price (£20/MWh)
- Remuneration = £20 (OBZ price) + £10 (calculated top-up) = £30/MWh
- This falls below expected revenues of £50/MWh

## Approach 2: CfD paid with reference to OBZ price

- CfD top-up is therefore £50 (strike price) - £20 (OBZ price) = £30/MWh
- Remuneration = £20 (OBZ price) + £30 (calculated top-up) = £50/MWh
- OSW farm is paid strike price in full

## Key takeaways

The establishment of a reference price prompts other considerations.

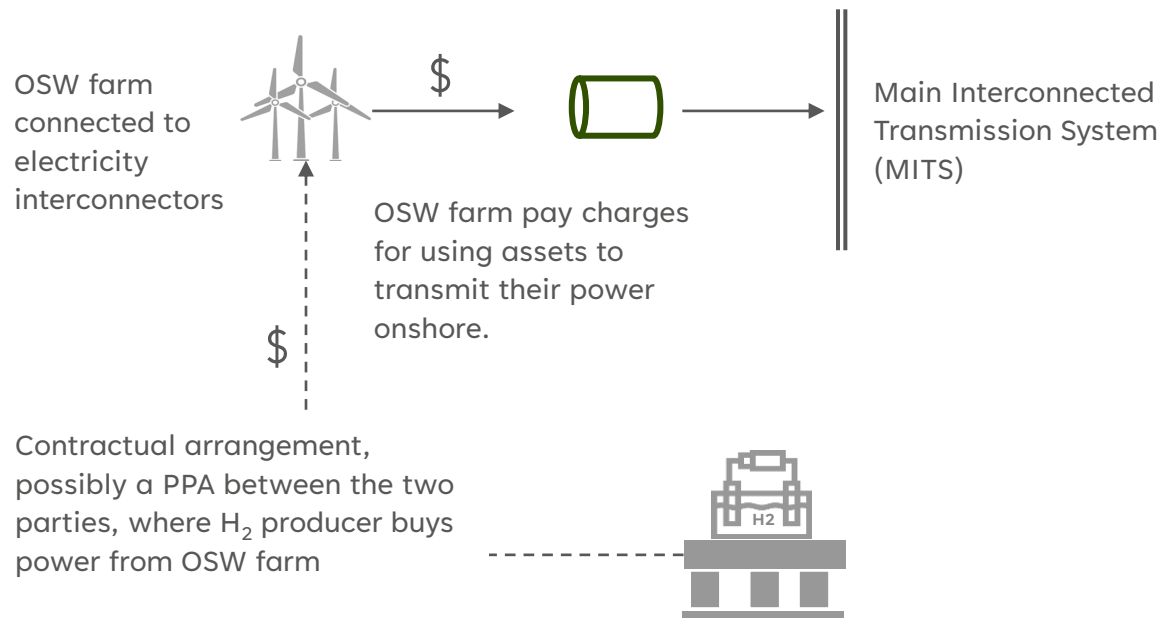
- If the OBZ strike price does include the cost of offshore electricity transportation (priced in by cross-market traders), offshore H<sub>2</sub> offtakers may not fully exploit the benefits of colocation as the OBZ price would be the same as onshore.
- If offshore wind farms can secure a direct PPA with an offshore offtaker at a more advantageous price than the CfD, they should be able to do so under a OBZ model. This could release additional CfD capacity for new OSW projects. This question is also important for alternative options being considered in REMA, such as Deemed CfDs or capacity-based CfDs.



# Charging – Charging methodology must ensure that there is sufficient incentive for developers to develop offshore

Currently, users of electricity interconnectors are charged a transmission fee by regulated networks and OFTOs

High level schematic of charging for electricity network users and operators



## Key takeaways

### Electricity Interconnectors

- OSW farms pay transmission charges to OFTOs for connection to the MITS onshore, this falls under the Transmission Network Use of System (TNUoS) regime.
- TNUoS charges apply to OSW farms that currently have priority access to GB wholesale markets and often do not have other offtakers (per the CfD restrictions).
- But OSW farms operating under OBZ arrangements, who don't have dedicated access to sell their power in GB markets and don't have ongoing access to the onshore transmission system, are not liable for TNUoS charges, under the regime.
- For OSW farms operating in a zonal market, congestion revenues between two zones reflect the cost of transmitting within the network. This would also inform the charges to be paid by OSW farms.
- However, for developers to operate offshore, charging methodologies must ensure that there is sufficient incentive (i.e., cheaper to operate than current status quo).

### Guaranteed offtaker entrant

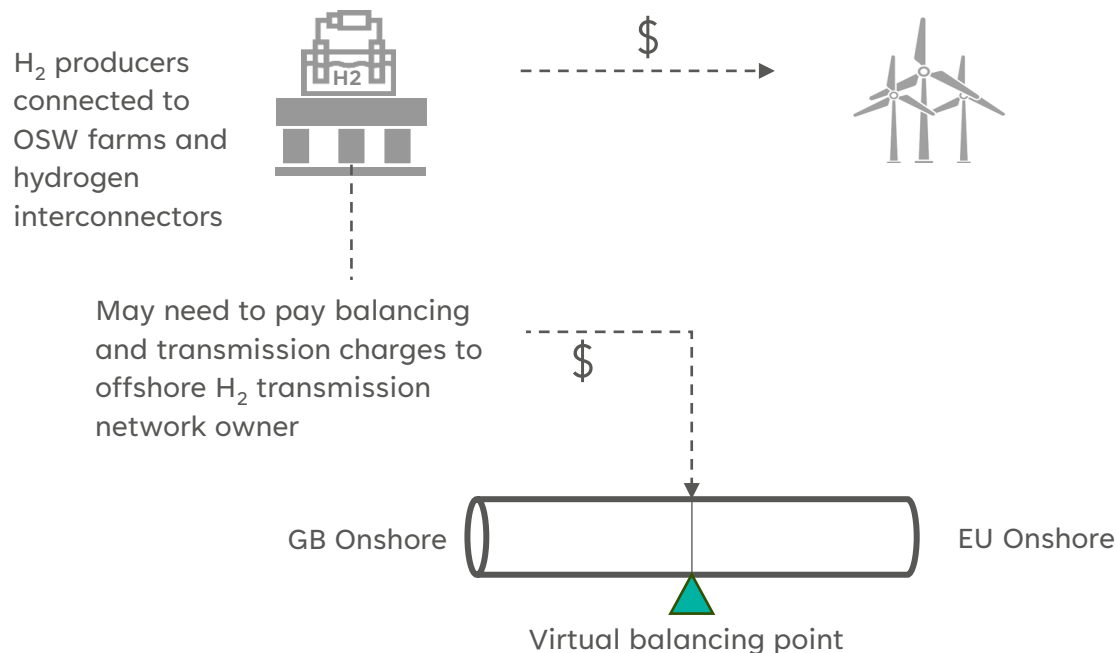
- If a guaranteed offtaker like the co-located H<sub>2</sub> producer in an OEH enters the picture, how will this affect OSW farm developer incentives?



# Charging – Similar to current interconnectors, offshore H<sub>2</sub> networks will have to operate under a low-risk profile

In OEHs, hydrogen producers may need to pay charges to the offshore hydrogen transmission owner.

High level schematic of charging for hydrogen network users and operators



## Key takeaways

Current gas interconnector charging methodologies may apply to hydrogen, however given the nascent nature of the market, careful consideration should be given to designing a methodology that unlocks the hydrogen market in GB.

- **What are the costs of constructing and operating?**
  - Charges should be designed to recover costs of building, operating and maintaining the H<sub>2</sub> interconnector. A reasonable ROI for the operators to encourage development and ensure FID can be reached. What reasonable may mean will be defined by market participants.
- **What type of tariff structure is optimal for cost recovery?**
  - Tariffs could be based on capacity reservation rather than actual usage to mitigate revenue risk for interconnector operators.
- **How can cross-border coordination be ensured?**
  - Interconnector charges may need to be harmonized with neighbouring markets to facilitate cross-border hydrogen trade.
- **What stakeholders must be engaged?**
  - Engage with stakeholders, including hydrogen producers, consumers, and other regulatory bodies

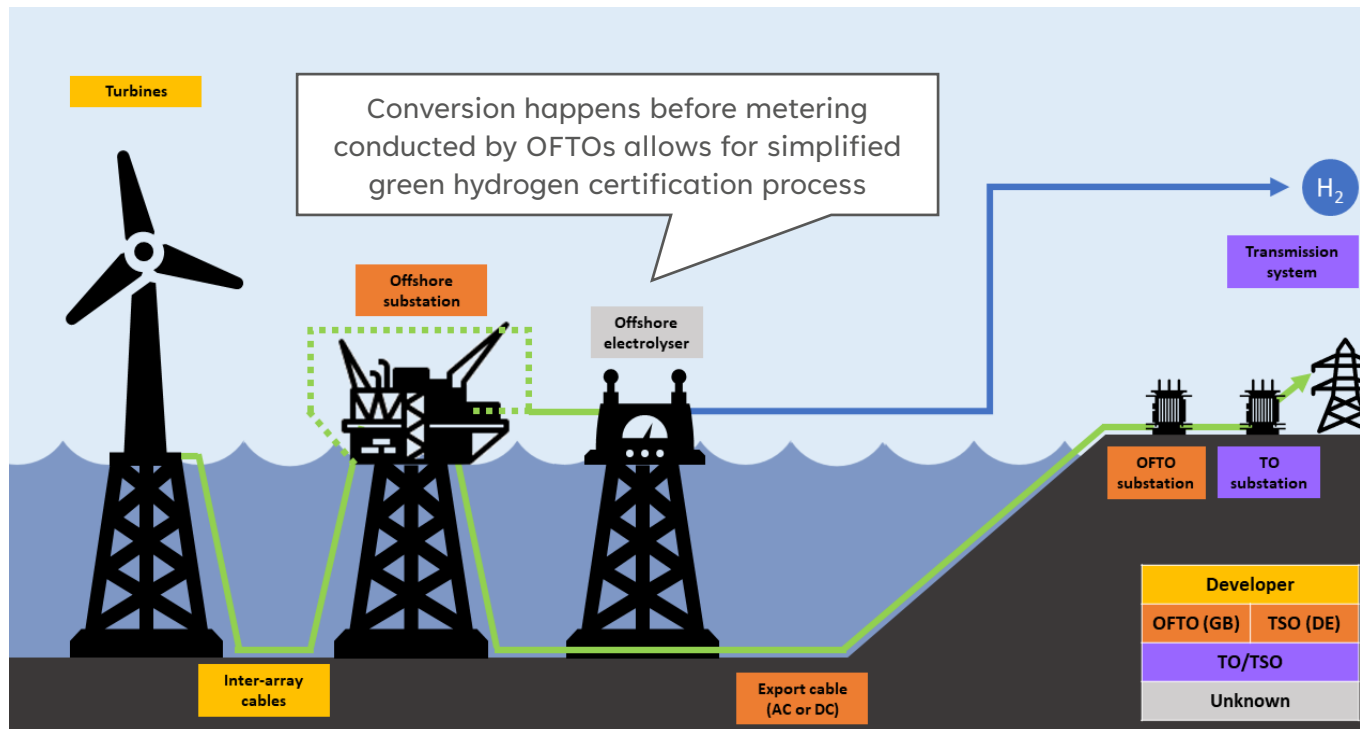
In conclusion, if regulated entities are to be involved in any offshore infrastructure, such as offshore hydrogen transmission networks, they will have to be incentivised to produce and transport by operating under low-risk revenue profiles and favourable charging methodologies.



# Metering – Offshore H<sub>2</sub> production facilitates Guarantee of Origin (GO) certification as producers can be considered BTM

Offshore hydrogen production can be considered behind the meter in GB

Offshore energy hub metering schematic



## Key takeaways

- Projects that convert offshore wind power to onshore hydrogen can encounter metering problems in the current GB metering design that hinders their development.
- This happens because the metering is conducted by the Offshore Transmission Owner (OFTO) before the conversion process. As a result, hydrogen production would be classified as Front of the Meter (FTM), which creates challenges in easily categorising it as green hydrogen. In comparison, hydrogen production that occurs offshore could be considered truly Behind-The-Meter (BTM), which simplifies the classification of offshore produced hydrogen as green hydrogen.
- The metering constitute a natural advantage and incentives for offshore hydrogen development. **To ensure this remains true in the context of offshore energy hub, the metering needs to be appropriately considered so that grid-imported electricity is metered differently from the one produced by the offshore wind farm.**



# Contractual arrangements – Additions and changes to codes and contracts may be required to include new OEH interactions

Codes and contractual arrangement form the basis by which parties within the energy market can operate. Additions may be required to incorporate the new interactions and arrangements brought about by OEHs



## Codes

Current industry codes form the foundation of the electricity and gas markets.

### Electricity codes

- Connection and Use of System Code (CUSC)
- Grid Code (GC)
- Balancing and Settlement Code (BSC)

### Gas codes

- Uniform Network Code (UNC)
- Independent Gas Transporter UNC (iGT UNC)

What new codes or changes are required to ensure OEH assets (e.g., H<sub>2</sub> assets) are covered?



## Contracts

Given the various parties involved in OEHs, contracts are crucial. PPAs are a common contract type between developers.

- PPAs are long-term contracts (10-20 years) between renewable energy (RE) suppliers and buyers, ensuring a stable energy source and investment. PPAs offer price certainty, either physically integrating renewable energy into the buyer's mix or financially securing forecasted generation.

Should offshore PPAs be considered the only truly physical PPAs linked to an OSW?

Careful consideration must be made when introducing changes to current industry codes or contracts on OEH infrastructure to the electricity and gas markets

- 1 Regulatory compliance:** New changes must comply with existing national industry codes and regulations for safety, technical and operational standards.
- 2 Synergy :** Codes should facilitate synergy between different energy vectors (electricity, hydrogen, CO<sub>2</sub>) and with onshore and offshore infrastructure. Ensuring standardisation of interfaces and protocols will lead better integration and operation.
- 3 Risk allocation:** Codes and contracts should clearly allocate liabilities between the different parties. Financial instruments may be used to mitigate risks in a new market. Risks and incentives should be handled by those who can control it.
- 4 International coordination:** Coordinate with international players and comply with cross-border regulations to facilitate smooth operation of commercial exchange.

# 5. Appendix

# Appendix A – OEH location and configurations

1 – Concept configuration

2 – Assumptions



# Every zone has its own benefits and challenges, driven by selected parameters and their importance

| Zone | General   |
|------|---|
| A    | <p><b>Benefits:</b> The area in question is an excellent location for maximizing power generation. It benefits from high potential wind speeds, the greatest number of oil platforms, and the largest potential for CO<sub>2</sub> storage. Additionally, there is already existing infrastructure for electricity and gas that can be repurposed. Furthermore, there are plans for a hydrogen pipeline that would connect Scotland and continental Europe, providing additional benefits for the area.</p> <p><b>Challenges:</b> The downside of the zone is its deep waters and long distance from the shore, most likely resulting in higher capital and operational expenditure.</p>  |
| B    | <p><b>Benefits:</b> This zone which hosts the majority of the GB's offshore wind production is currently the preferred zone for this industry. This location is preferred due to its shallow waters, which is also beneficial for the offshore hub concept. There are various advantageous factors for the hub's development, such as the presence of numerous gas platforms, the potential for CO<sub>2</sub> storage, and the proximity of existing electricity and gas connections. This zone is also located near existing offshore gas storage facilities (e.g., Rough storage operated by Centrica) that potentially could be repurposed to hydrogen at a later date.</p> <p><b>Challenges:</b> This zone does not have many downsides for offshore development but could be potentially constrained by space in the long term.</p> |
| C    | <p><b>Benefits:</b> This zone offers several advantages, including its proximity to the EU's offshore hubs and shallow waters. Its excellent connectivity with both Europe and the GB makes it ideal for multi-purpose interconnectors.</p> <p><b>Challenges:</b> This zone has a relatively average annual mean wind speed potential compared to the rest of the North Sea and could also be constrained by space in the long term. For this study, it is assumed that the existing gas network in the area is not repurposed due to strategic importance, serving as a link between GB and Netherlands/Belgium. Therefore, newly built hydrogen infrastructure is considered.</p>   |

# Characteristics of each zone have a direct impact on the configuration of LookNorthH2, making each configuration unique

## Important to note



Every zone has its characteristics; therefore, the design of an offshore energy hub would be dependent on the location and therefore the list of components required would be different. For example, Zone A has deep waters and therefore floating offshore wind is considered. The complexity level represents the complexity level of installing offshore energy hubs at specific zones, despite the zone potentially being very beneficial.

1

### Zone A

#### Components:

**Electric interconnection:** HVDC  
**Offshore wind platform:** Floating  
**Hub platform:** Partly repurposed oil platform  
**CO<sub>2</sub> storage:** Yes  
**Offshore Hydrogen production:** Yes  
**Offshore hydrogen storage:** No

2

### Zone B

#### Components:

**Electric interconnection:** HVAC  
**Offshore wind platform:** Fixed  
**Hub platform:** Partly repurposed gas platform  
**CO<sub>2</sub> storage:** Yes  
**Offshore Hydrogen production:** Yes  
**Offshore hydrogen storage:** Yes

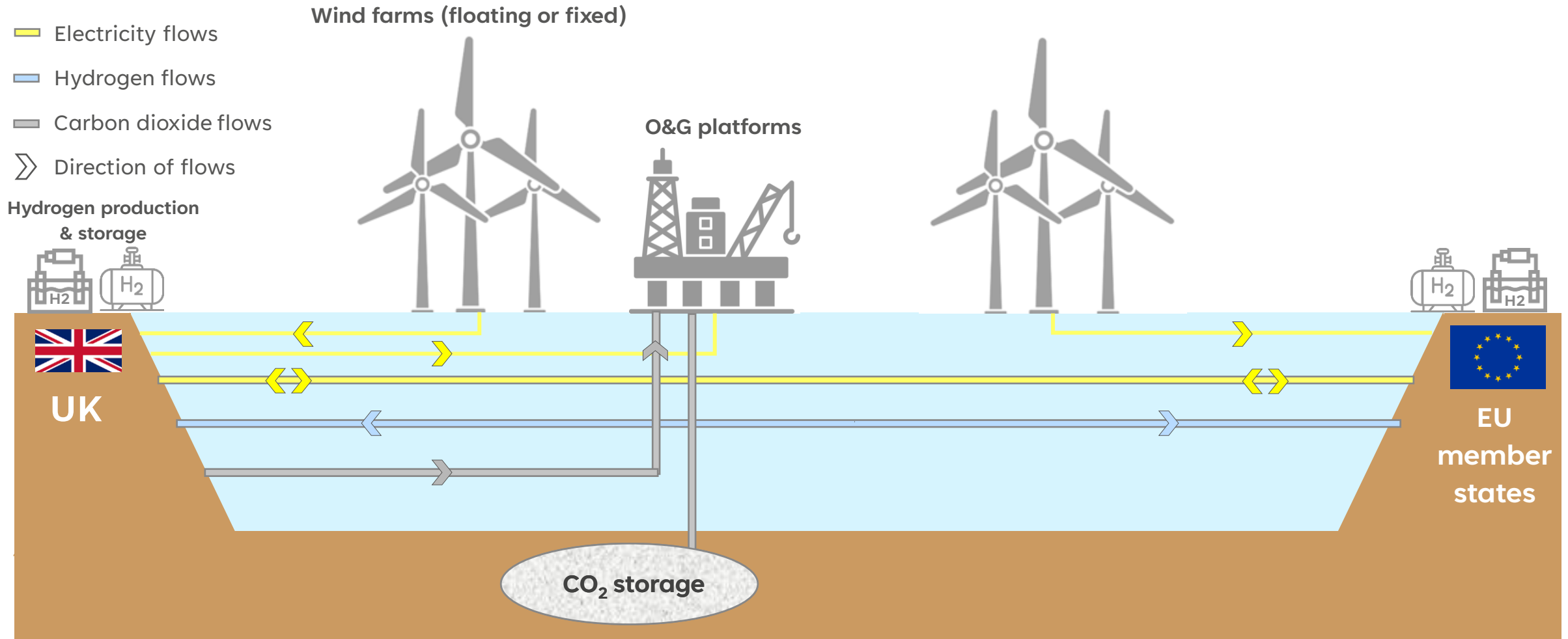
3

### Zone C

#### Components:

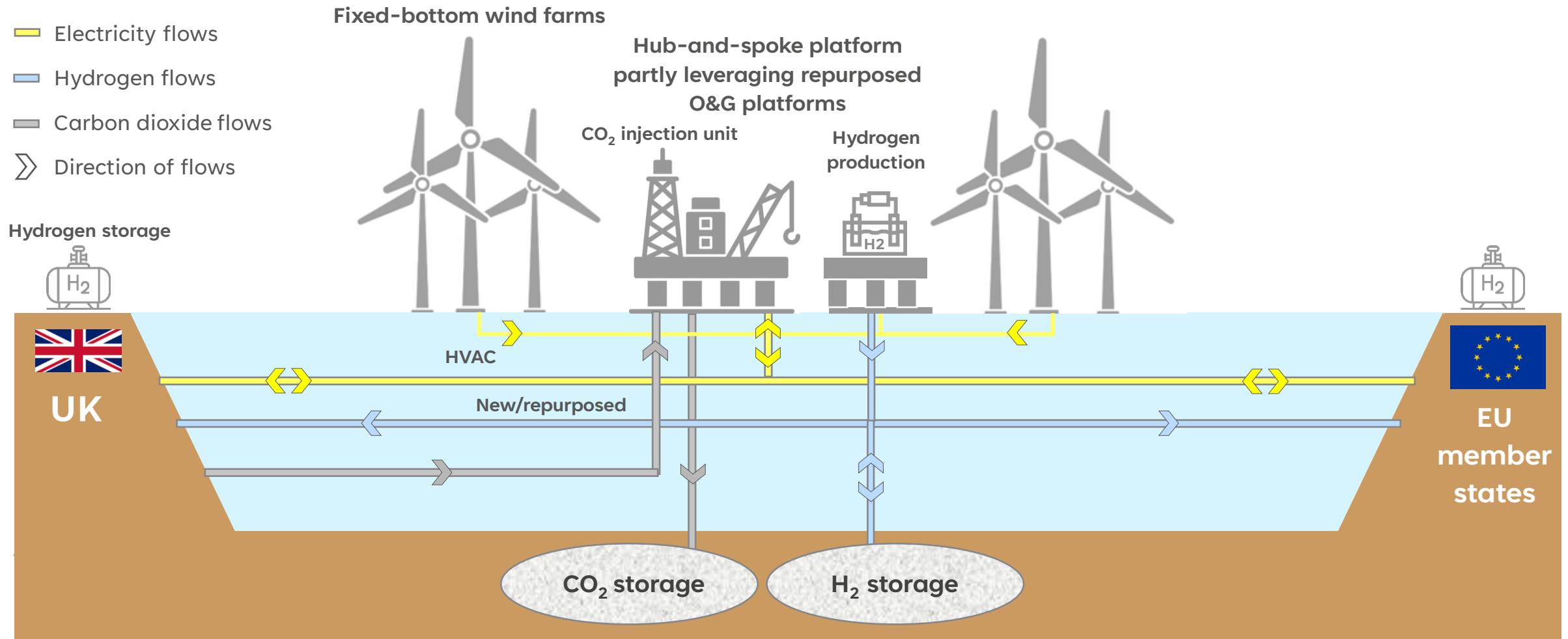
**Electric interconnection:** HVDC  
**Offshore wind platform:** Fixed  
**Hub platform:** Fully new built platform  
**CO<sub>2</sub> storage:** Yes  
**Offshore Hydrogen production:** Yes  
**Offshore hydrogen storage:** No

# Counterfactual - decentralised offshore electricity production, bringing electricity to the shore for hydrogen production

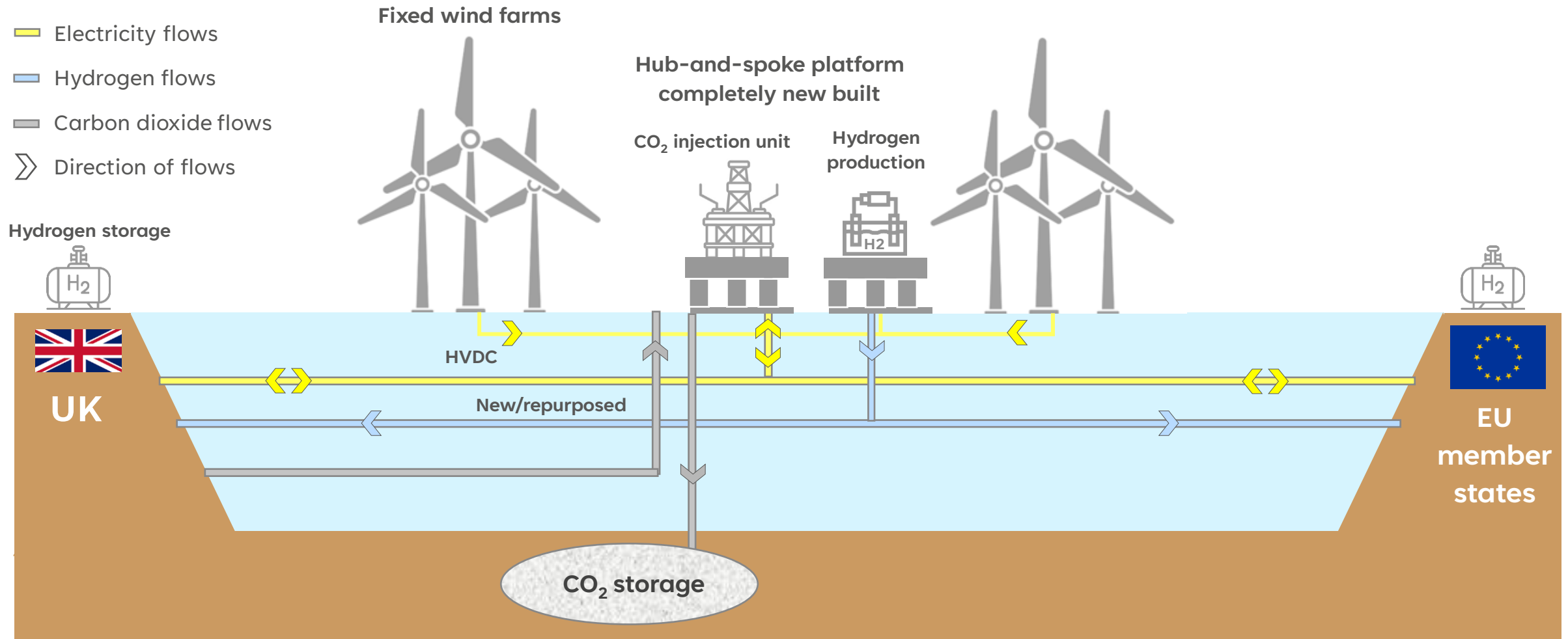




# Zone B – centralised electricity and hydrogen production via fixed wind on repurposed gas platforms with CO<sub>2</sub> storage



# Zone C - centralised electricity and hydrogen production via floating wind on newly built platforms with no CO<sub>2</sub> storage



# Benefits of the innovation are measured across economic, environmental and social variables

1

Economic (£)

**Description:**

Economic benefits are a key metric as they directly translate into financial savings on consumer energy bills. In this project, we expect these economic benefits to come from multiple variables, including a reduction in the cost of operating the network thanks to reduced curtailment payments, a reduction in energy losses and the buildout of more efficient infrastructure which would reduce the levelised cost of electricity and hydrogen, thus lowering consumer bills.

**Included benefits streams:**

- B1. Curtailment reduction - £/year
- B2. Energy transmission losses reduction - £/year
- B3. Infrastructure optimisation savings - £
- B4. Avoided cost of asset decommissioning - £

2

Environmental (tonnes of CO<sub>2</sub>)**Description:**

The UK is committed to achieving a net-zero power system by 2035 and a net-zero economy by 2050. The primary environmental goal of this effort is to reduce CO<sub>2</sub> emissions. The majority of the CO<sub>2</sub> reduction is expected to be indirect, through the conservation of energy. This conservation of energy will come primarily from avoided curtailment and reduced energy transmission losses.

**Included benefits streams:**

- BE1\*. Indirect CO<sub>2</sub> emission reduction from additional green energy production (linked to avoided curtailment) - CO<sub>2</sub>e/year
- BE2\*. Indirect CO<sub>2</sub> emission reduction from additional green energy delivered (link to reduced energy transmission losses) - CO<sub>2</sub>e/year

3

Social (number of jobs)

**Description:**

Social benefits includes the number of jobs that can be saved and created thanks to offshore energy hubs. The direct social benefit relates to jobs created by offshore platform operations. In the UK, the O&G industry employs thousands of people with expertise in offshore operations that can be leveraged in this project. Additionally, there are indirect and induced job creation from the economic benefits identified in the first pillar, however, this will be explored in the Alpha phase.

**Included benefits streams:**

- BS1. Direct job saving and creation from preserving offshore platform operation

# CBA Assumptions (1/4)

| Input  | Values       | Unit                 | Source   | Note  |
|--|--------------|----------------------|--|---|
| Hydrogen onshore cost                        | 535          | £/MW-km              | <a href="#">European Hydrogen Backbone 2023</a>                                    | Assume 10 GW pipeline   |
| Hydrogen offshore cost                       | 910          | £/MW-km              | <a href="#">European Hydrogen Backbone 2023</a>                                    | Assume 10 GW pipeline   |
| Hydrogen repurposed onshore cost             | 149          | £/MW-km              | <a href="#">European Hydrogen Backbone 2023</a>                                    | Assume 10 GW pipeline   |
| Hydrogen repurposed offshore cost            | 349          | £/MW-km              | <a href="#">NZTTP Hydrogen Backbone</a>  | Based on the 10 GW pipeline, where the initial cost of 279 is increased by 20% (to account for sizing |
| Hydrogen OPEX cost                           | 0.01         | % of CAPEX           | <a href="#">European Hydrogen Backbone 2023</a>                                    | Assumes that OPEX to be proportional to the CAPEX   |
| HVAC fixed cost                              | - 141,000    | £/MW                 | <a href="#">Offshore wind system integration 2030-2040</a>                         | Includes HVAC platform  |
| HVAC variable cost                           | - 2,000      | £/MW-km              | <a href="#">Offshore wind system integration 2030-2040</a>                         | Includes HVAC cable   |
| HVDC platform cost                           | - 300,000    | £/MW                 | <a href="#">Offshore wind system integration 2030-2040</a>                         | Includes HVDC platform  |
| HVDC converter cost                          | - 250,000    | £/MW                 | <a href="#">Offshore wind system integration 2030-2040</a>                         | Includes 2 HVDC converters of 125000 each   |
| HVDC variable cost                           | - 1,100      | £/MW-km              | <a href="#">Offshore wind system integration 2030-2040</a>                         | Includes HVDC cable   |
| Assumed AC Line losses                       | 0.09         | % per 1,000km        | <a href="#">Offshore wind system integration 2030-2040</a>                         | HVAC cables result in high losses   |
| Assumed DC Line losses                       | 0.03         | % per 1,000km        | <a href="#">Offshore wind system integration 2030-2040</a>                         | HVDC cables result in lower losses  |
| Assumed H2 pipe losses                       | 0.001        | % per 1,000km        | <a href="#">European Hydrogen Backbone 2023</a>                                    | Negligible losses for H2 pipeline   |
| Assumed AC Line losses                       | 0.09         | % per 1,000km        | <a href="#">Offshore wind system integration 2030-2040</a>                         | HVAC cables result in high losses   |
| Assumed DC Line losses                       | 0.03         | % per 1,000km        | <a href="#">Offshore wind system integration 2030-2040</a>                         | HVDC cables result in lower losses  |
| Assumed H2 pipe losses                       | 0.001        | % per 1,000km        | <a href="#">European Hydrogen Backbone 2023</a>                                    | Negligible losses for H2 pipeline   |
| Platform cost (no equipment)                 | - 80,000,000 | £                    | <a href="#">Offshore Energy Mag 2021</a>   | Average cost of new O&G platform with no equipment  |
| Decommissioning cost                         | - 80,000,000 | £                    | <a href="#">Think Geoenergy - Decommissioning North Sea O&amp;G platforms 2021</a> | Assumes the cost to be identical to building a new one  |
| Platform size (surface area)                 | 6,300        | m <sup>2</sup>       | <a href="#">Nesfircroft</a>  | Assume largest existing O&G offshore platform   |
| Electrolyser size (1 MW)                     | 13           | m <sup>2</sup>       | <a href="#">Nel Hydrogen</a>   | Fits in 20 ft container   |
| Electricity emission factor (generation/kwh) | 0.2          | kg CO <sub>2</sub> e | <a href="#">UK Government Emissions Factors</a>                                    | Based on 2021 grid mix data   |
| Natural gas emission factor (generation/kwh) | 0.18         | kg CO <sub>2</sub> e | <a href="#">UK Government Emissions Factors</a>                                    | Based on 2023 data  |
| Number of existing oil & gas offshore jobs   | 200,800      | people               | <a href="#">OE UK</a>  | Based on 2022 data, total jobs in offshore platforms in the North Sea                                 |



# CBA Assumptions (2/4)

| Input   | Values    | Unit         | Source   | Note   |
|---|-----------|--------------|--|--|
| Number of existing oil & gas offshore jobs    | 200,800   | people       | <a href="#">OE UK</a>                                      | Based on 2022 data, total jobs in offshore platforms in the North Sea                          |
| Number of oil & gas platforms                 | 590       | platforms    | <a href="#">Marine Policy</a>                              | Based on 2023 data, total number of offshore platforms in the North Sea                        |
| Offshore wind curtailment                     | 20%       | %            | <a href="#">Carbon Tracker</a>                             | The energy wasted equates to roughly 20%   |
| Revenue from Hydrogen                         | 60        | £/mwh        | <a href="#">BEIS Hydrogen production costs 2021</a>        | Assume dedicated production in 2040  |
| Revenue from Electricity                      | 50        | £/mwh        | <a href="#">Sustainability by numbers</a>                  | Assume the wholesale electricity price to be roughly £20 higher than the levelised cost of £30 |
| Offshore wind load factor (2024)              | 47%       | %            | <a href="#">SPG Global</a>                                 | Average load factor for all offshore wind projects in the UK                                   |
| Offshore wind load factor (2030)              | 57%       | %            | <a href="#">SPG Global</a>                                 | Average load factor for all offshore wind projects in the UK                                   |
| Offshore wind load factor (2040)              | 63%       | %            | <a href="#">SPG Global</a>                                 | Average load factor for all offshore wind projects in the UK                                   |
| Electricity cable lifetime                    | 30        | years        | <a href="#">Offshore wind system integration 2030-2040</a> | Assume to be 40 years in the current study   |
| Hydrogen pipeline lifetime                    | 30        | years        | <a href="#">Hydrogen Backbone</a>                          | Assume to be 40 years in the current study   |
| Onshore PEM electrolyser Capex (2024)         | - 730,000 | £/MW H2      | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser Capex (2030)         | - 562,000 | £/MW H2      | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser Capex (2040)         | - 477,000 | £/MW H2      | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser Capex (2050)         | - 458,000 | £/MW H2      | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser fixed Opex (2024)    | - 34,720  | £/MW H2/year | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser fixed Opex (2030)    | - 33,380  | £/MW H2/year | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser fixed Opex (2040)    | - 32,380  | £/MW H2/year | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser fixed Opex (2050)    | - 32,050  | £/MW H2/year | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser variable Opex (2024) | - 4       | £/MWh H2     | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser variable Opex (2030) | - 3       | £/MWh H2     | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser variable Opex (2040) | - 3       | £/MWh H2     | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Onshore PEM electrolyser variable Opex (2050) | - 3       | £/MWh H2     | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking the 'Medium' forecasted scenario  |
| Electrolyser lifetime                         | 30        | years        | <a href="#">BEIS Hydrogen production costs 2021</a>        | Taking system lifetime instead of the stack lifetime   |

# CBA Assumptions (3/4)

| Input                                    | Values      | Unit  | Source  | Note  |
|--|-------------|-------|---|---|
| Electrolyser capacity factor             | 98%         | %     | <a href="#">BEIS Hydrogen production costs 2021</a>                         | The remaining 2% represent the O&M downtime |
| Electrolyser efficiency PEM (2024)       | 77%         | %     | <a href="#">BEIS Hydrogen production costs 2021</a>                         | Taking the 'Medium' forecasted scenario     |
| Electrolyser efficiency PEM (2030)       | 77%         | %     | <a href="#">BEIS Hydrogen production costs 2021</a>                         | Taking the 'Medium' forecasted scenario     |
| Electrolyser efficiency PEM (2040)       | 83%         | %     | <a href="#">BEIS Hydrogen production costs 2021</a>                         | Taking the 'Medium' forecasted scenario     |
| Electrolyser efficiency PEM (2050)       | 83%         | %     | <a href="#">BEIS Hydrogen production costs 2021</a>                         | Taking the 'Medium' forecasted scenario     |
| Fixed offshore wind CAPEX (2024)         | - 1,275,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind CAPEX (2030)         | - 1,275,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind CAPEX (2040)         | - 1,137,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind CAPEX (2050)         | - 1,061,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind fixed OPEX (2024)    | - 24,019    | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind fixed OPEX (2030)    | - 24,019    | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind fixed OPEX (2040)    | - 20,948    | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind fixed OPEX (2050)    | - 19,452    | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind variable OPEX (2024) | - 3         | £/MWh | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind variable OPEX (2030) | - 3         | £/MWh | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind variable OPEX (2040) | - 3         | £/MWh | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Fixed offshore wind variable OPEX (2050) | - 3         | £/MWh | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Floating offshore wind CAPEX (2024)      | - 1,723,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Floating offshore wind CAPEX (2030)      | - 1,723,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Floating offshore wind CAPEX (2040)      | - 1,535,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Floating offshore wind CAPEX (2050)      | - 1,433,000 | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Floating offshore wind fixed OPEX (2024) | - 32,400    | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |
| Floating offshore wind fixed OPEX (2030) | - 32,400    | £/MW  | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario        |

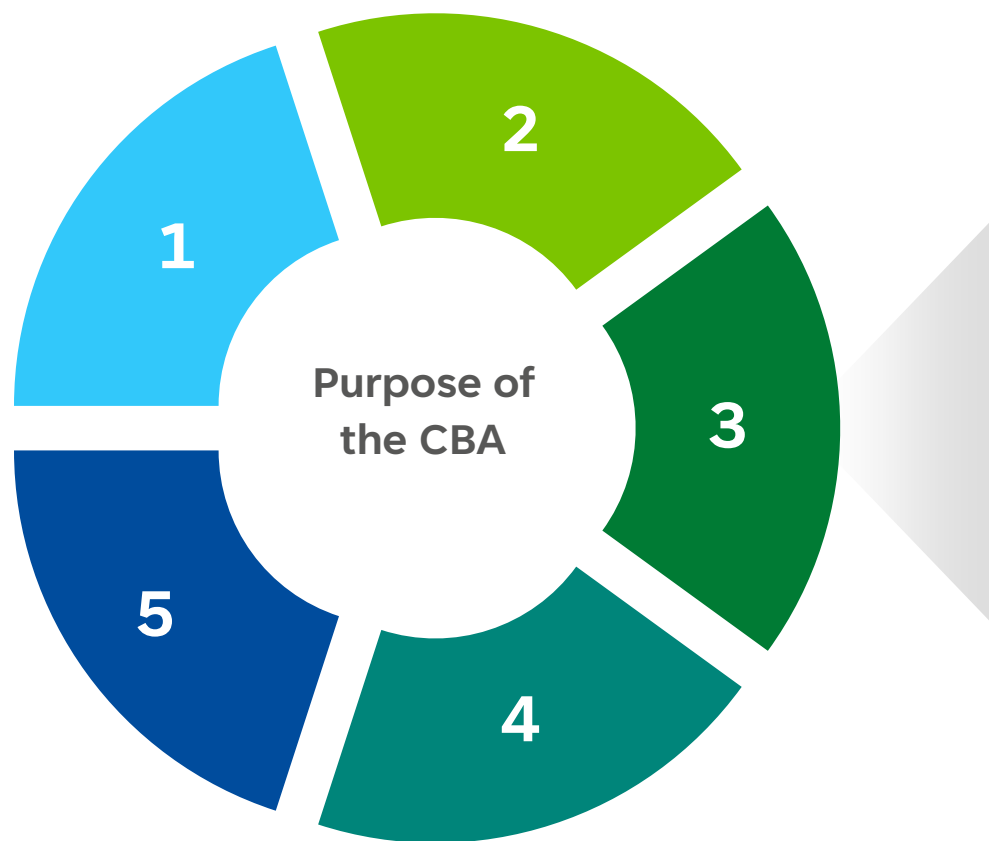
# CBA Assumptions (4/4)

| Input   | Values      | Unit             | Source  | Note  |
|---|-------------|------------------|---|---|
| Floating offshore wind fixed OPEX (2040)        | - 28,260    | £/MW             | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario  |
| Floating offshore wind fixed OPEX (2050)        | - 26,260    | £/MW             | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario  |
| Floating offshore wind variable OPEX (2024)     | - 3         | £/MWh            | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario  |
| Floating offshore wind variable OPEX (2030)     | - 3         | £/MWh            | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario  |
| Floating offshore wind variable OPEX (2040)     | - 3         | £/MWh            | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario  |
| Floating offshore wind variable OPEX (2050)     | - 3         | £/MWh            | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Taking the 'Low' forecasted scenario  |
| Offshore wind turbine lifetime (fixed/floating) | 25          | years            | <a href="#">Danish Energy Agency and Energinet (2020), ENTSO-E/G (2022)</a> | Extending it to 40 years for this study   |
| Saltwater electrolysis efficiency (2039-)       | 83%         | %                | <a href="#">International Journal of Hydrogen Energy</a>                    | Assume to be the same as existing technologies such as PEM used in counterfactual |
| Offshore electrolyser Capex (2040)              | - 477,000   | £/MW H2          | <a href="#">World Economic Forum</a>  | Assumed to be the same as existing technologies such as PEM                       |
| Offshore electrolyser Capex (2050)              | - 458,000   | £/MW H2          | <a href="#">World Economic Forum</a>  | Assumed to be the same as existing technologies such as PEM                       |
| Offshore electrolyser fixed Opex (2040)         | - 32,380    | £/MW H2/year     | <a href="#">World Economic Forum</a>  | Assumed to be the same as existing technologies such as PEM                       |
| Offshore PEM electrolyser fixed Opex (2050)     | - 32,050    | £/MW H2/year     | <a href="#">World Economic Forum</a>  | Assumed to be the same as existing technologies such as PEM                       |
| Offshore PEM electrolyser variable Opex (2040)  | - 3         | £/MWh H2         | <a href="#">World Economic Forum</a>  | Assumed to be the same as existing technologies such as PEM                       |
| Offshore PEM electrolyser variable Opex (2050)  | - 3         | £/MWh H2         | <a href="#">World Economic Forum</a>  | Assumed to be the same as existing technologies such as PEM                       |
| Offshore O&G platform annual consumption        | 16,425      | cubic meters     | <a href="#">ipieca</a>  | Based on the 45 cubic meter daily consumption                                     |
| Natural gas emissions                           | 11.8        | kgCO2/kgH2       | <a href="#">Hydrogen Council</a>  | Taking natural gas emissions associated with grey hydrogen                        |
| Energy content of hydrogen (LHV)                | 33.33       | kwh/kgH2         | <a href="#">Enapter</a>   | Taking LHV  |
| CO2 Injection well cost (per platform) - CAPEX  | 114,000,000 | £m per 1 cluster | <a href="#">Global CCS Institute</a>  | Assumin low cost scenario for offshore storage in depleted O&G fields             |
| CO2 Injection well cost (per platform) - OPEX   | 5,400,000   | £m per 1 cluster | <a href="#">Global CCS Institute</a>  | Assumin low cost scenario for offshore storage in depleted O&G fields             |
| CO2 Injection well lifetime                     | 40          | years            | <a href="#">Global CCS Institute</a>  | Assumin low cost scenario for offshore storage in depleted O&G fields             |
| CO2 Injection well capacity                     | 200         | tCO2             | <a href="#">Global CCS Institute</a>  | Assumin low cost scenario for offshore storage in depleted O&G fields             |
| CO2 Injection well electricity consumption      | 0.3         | MWh/tCO2         | <a href="#">Energies 2019</a>   | Approximated consumption  |
| CO2 emissions per 1 kg of diesel                | 2.56        | kgCO2            | <a href="#">Carbon+Alt+Delete</a>   | Value per liter converted per kg  |

# Appendix B – CBA

- 1 – Purpose of CBA
- 2 – Definition of scope
- 3 – Benefit streams
- 4 – Cost streams
- 5 – Financial comparisons
- 6 – Selection of sensitivities

# The purpose of the CBA is to provide evidence that the proposed innovation will generate more benefits than costs in GB



## The CBA will...

1

Provide an ex-ante indication of the costs and benefits that are associated with the development of multiple offshore energy hubs design in Great Britain (GB).

2

Enable the comparison between multiple offshore energy hub designs and the selection of which locations / configurations can provide the most benefits at the lowest cost.

3

Inform policymakers of the potential added value for GB taxpayers and who are the main beneficiaries. Which would in turn drive a case for adapting policy and regulatory change.

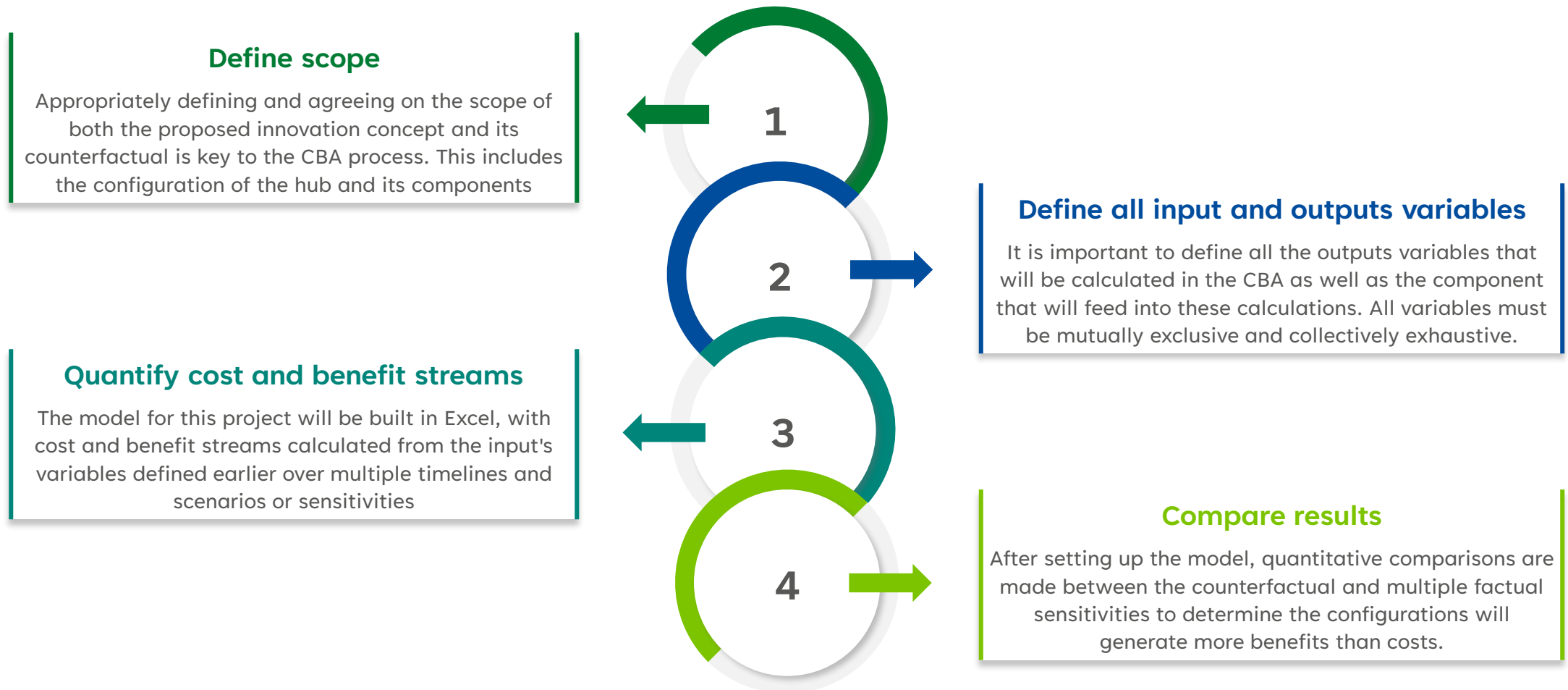
4

Provide evidence to potential project developers on the potential positive business case for developing offshore energy hubs. It also provides insights into the most financially viable technical and commercial configuration of offshore energy hubs

5

Serve as a source of information for subsequent discussions between stakeholders / countries on how costs and benefits potentially need to be re-allocated (i.e., cross-border cost allocation)

# The methodology of CBA involves four crucial stages, beginning with a clear definition of the scope, as done in this report

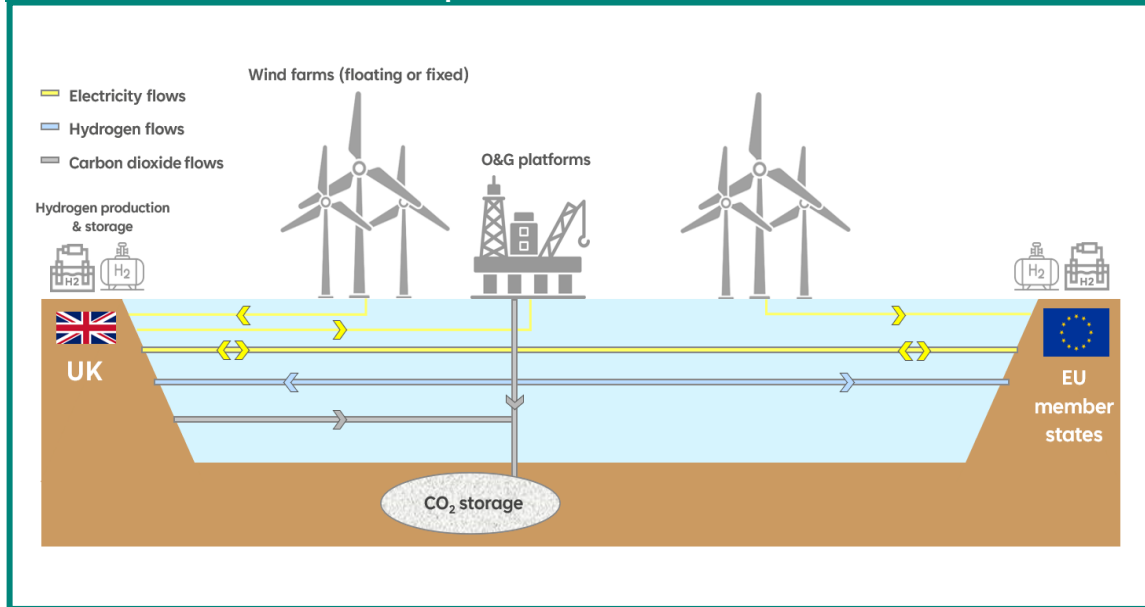


# The LookNorthH2 concept explores the repurposing of O&G infrastructure for hydrogen production and carbon capture

Optimising energy production is key to achieving the 2050 net zero target at the lowest cost for consumers. The UK is set to rely on offshore wind for most of its final power and energy use. A centralised offshore energy hub concept may be able to provide significant socio-economic and environmental benefits by integrating use cases.

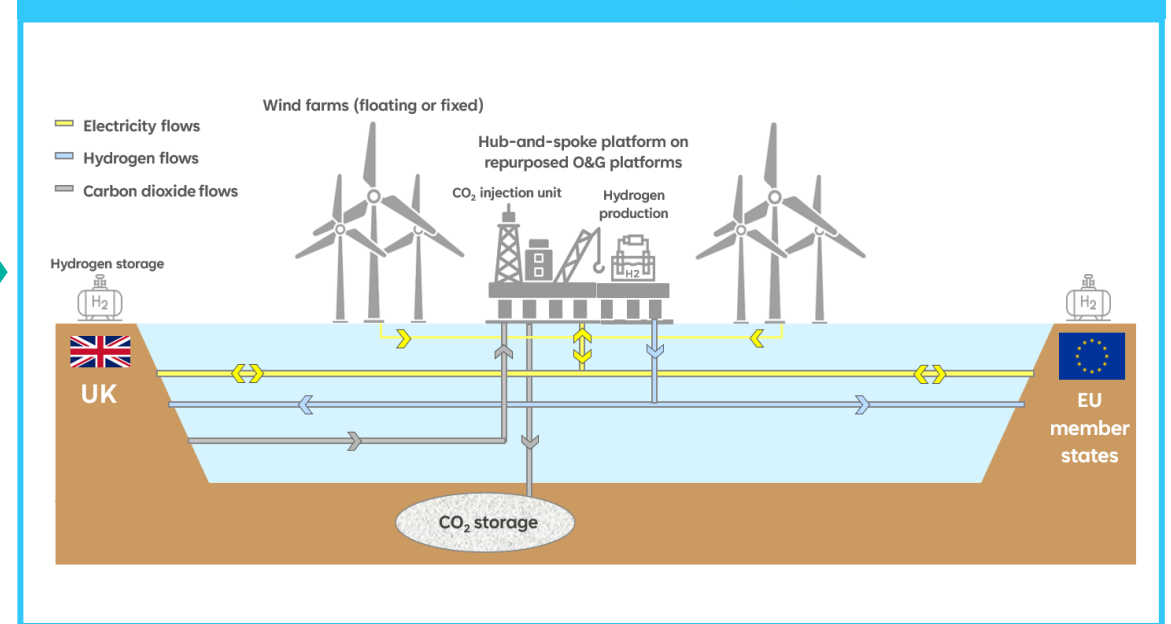
## Counterfactual

### BAU - Decentralised electricity production & electrolyser location for hydrogen production onshore



## Factual

### LookNorthH2 - Centralised electricity & hydrogen production offshore



# The factual represents a future with full cross-border offshore coordination between power and gas systems

The offshore energy hub concept explored in this project aims to centralise power production towards a repurposed oil & gas platform, which had been supplied by offshore wind to decarbonise

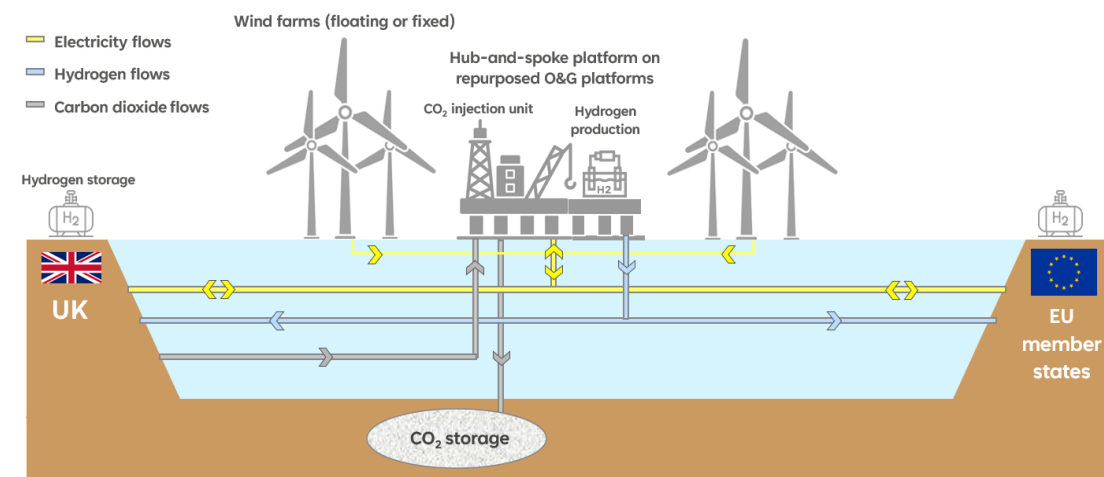
## Look NorthH2 - Factual

**Overview:** The offshore energy hub concept explored in this project aims to centralise offshore wind power production to a repurposed O&G platform. The connection between the wind farm and the O&G platform was formed before the creation of the hub to decarbonise its scope 1 & 2 activities. The existing O&G infrastructure, including the pipeline, the extraction unit and the extraction cavity are also repurposed to transport and store CO<sub>2</sub>. Hydrogen production is integrated to the platform and connected to the shore through either repurposed or new pipes. The power produced by wind farms is centralised to the platform and connected to both UK and European shore through a large interconnector sized appropriately. This provides optionality for electrons to power the CO<sub>2</sub> injection unit, be sold in the UK or European wholesale market, or produce hydrogen.

### Key components:

1. **Offshore wind turbines/transmission** connected to the hub via HVDC/HVAC, then electricity is transported to the shore via a larger HVDC/HVAC connection
2. **Electrolysers** (either Alkaline or Polymer Electrolyte Membrane (PEM)) are placed on the platform, producing hydrogen from electricity supplied to the hub. Hub assumes the co-location of desalinisation plants / electrolysers ran on salt water.
3. **Hydrogen storage** located onshore (same as BAU).
4. **CO<sub>2</sub> storage** connected via dedicated pipelines from the shore via a CO<sub>2</sub> injection unit powered by the wind farms.

## LookNorthH2 – Centralised electricity & hydrogen production offshore

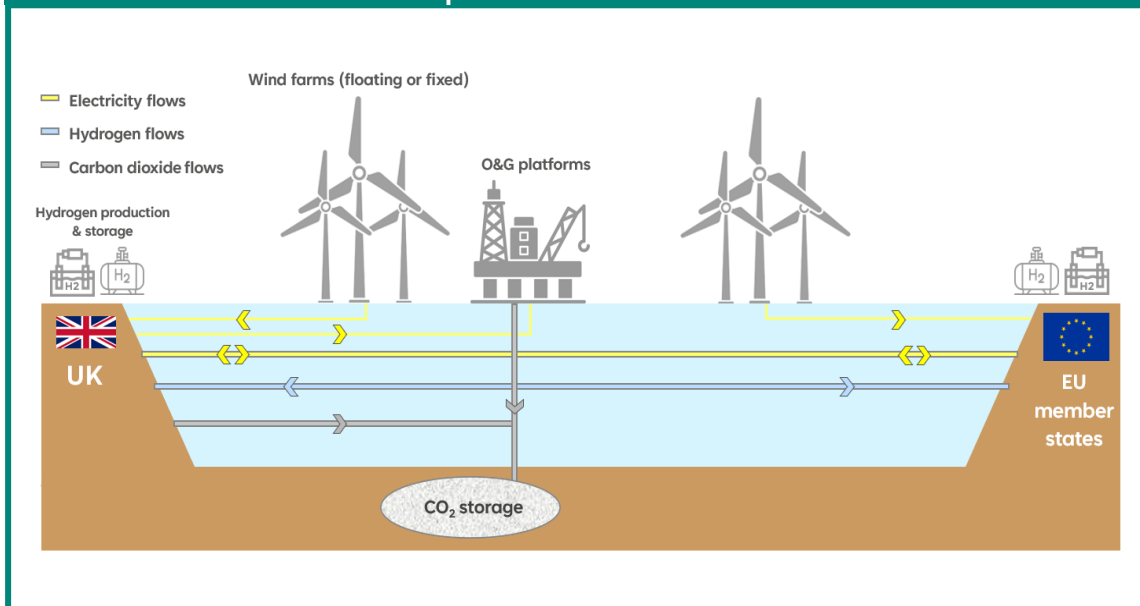




# The counterfactual is defined as a future without offshore integration, with the same CO<sub>2</sub> storage and hydrogen demand

The BAU case reflects today's system organisation, where offshore electricity production is decentralised and connected to shore through radial design, usually the shortest distance between the farm and land. To create a BAU, we have included hydrogen production onshore and both power and hydrogen interconnection with Europe

## BAU – Decentralised electricity production & electrolyser location for hydrogen production onshore



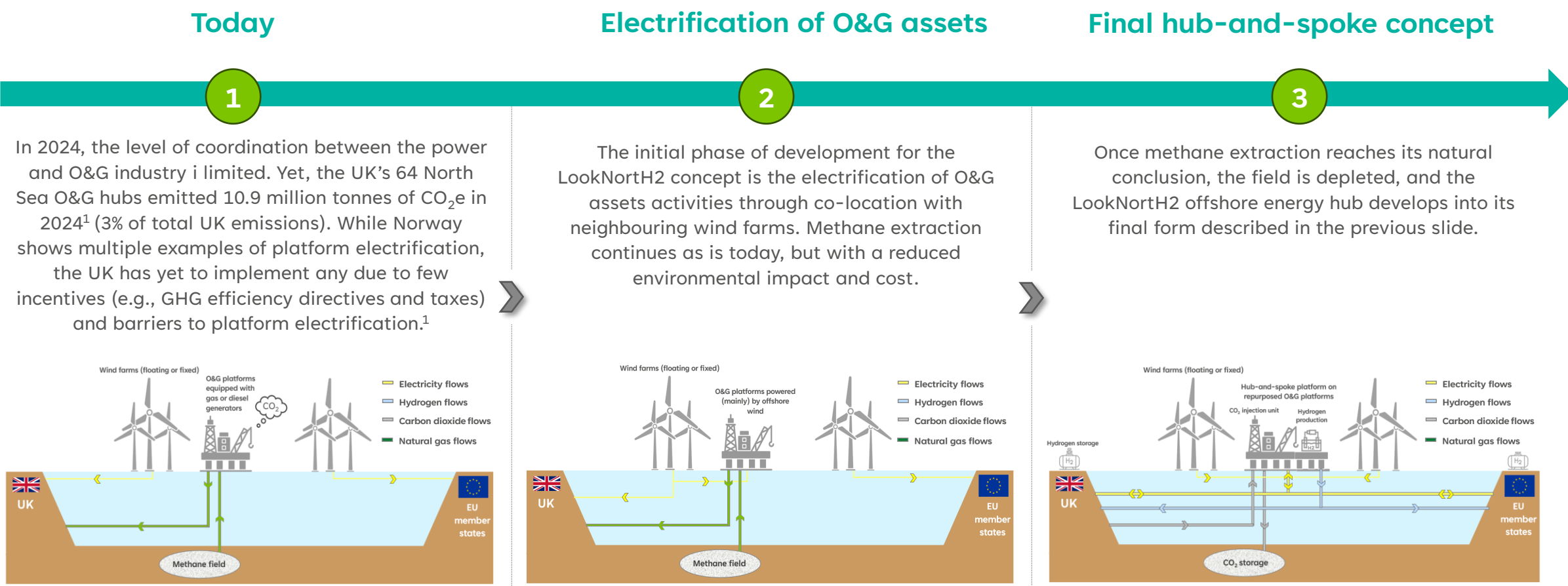
## BAU – Counterfactual

**Overview:** The BAU case applies a conservative approach where it is assumed that electricity produced will remain decentralised with multiple connections to the shore's electricity grid, transporting the electricity to both the end-consumers producing and electrolyzers for green hydrogen production. In the BAU case, the CO<sub>2</sub> is transferred from the shore to the offshore underground storage.

### Key components:

1. **Offshore wind turbines/transmission** have a dedicated transmission to the shore (radial design)
2. **Electrolysers** (either Alkaline or Polymer Electrolyte Membrane (PEM)) are located onshore with a connection to the grid, allowing continuous hydrogen production.
3. **Hydrogen storage** located onshore.
4. **CO<sub>2</sub> storage** connected via dedicated pipelines from the shore via a CO<sub>2</sub> injection unit powered by an electricity cable from the shore.

# Costs and benefits should be calculated throughout the concept formation, including the initial electrification of O&G assets



**Note:** The exact timing of these transitions will be defined later, after discussions with key partners

# Benefits of the innovation will be measured across economic, environmental and social variables

1

Economic (£)



## Description:

Economic benefits are a key metric as they directly translate into financial savings on consumer energy bills. In this project, we expect these economic benefits to come from multiple variables, including a reduction in the cost of operating the network thanks to reduced curtailment payments, a reduction in energy losses and the buildout of more efficient infrastructure which would reduce the levelised cost of electricity and hydrogen, thus lowering consumer bills.

## Included benefits streams:

- B1. Curtailment reduction - £/year
- B2. Energy transmission losses reduction - £/year
- B3. Infrastructure optimisation savings - £
- B4. Avoided cost of asset decommissioning - £

2

Environmental (tonnes of CO<sub>2</sub>)

## Description:

The UK is committed to achieving a net-zero power system by 2035 and a net-zero economy by 2050. The primary environmental goal of this effort is to reduce CO<sub>2</sub> emissions. The majority of the CO<sub>2</sub> reduction is expected to be indirect, through the conservation of energy. This conservation of energy will come primarily from avoided curtailment and reduced energy transmission losses.

## Included benefits streams:

- BE1. Indirect CO<sub>2</sub> emission reduction from additional green energy production (linked to avoided curtailment) - CO<sub>2</sub>e/year
- BE2. Indirect CO<sub>2</sub> emission reduction from additional green energy delivered (link to reduced energy transmission losses) - CO<sub>2</sub>e/year

3

Social (number of jobs)



## Description:

Social benefits includes the number of jobs that can be saved and created thanks to offshore energy hubs. The direct social benefit relates to jobs created by offshore platform operations. In the UK, the O&G industry employs thousands of people with expertise in offshore operations that can be leveraged in this project. Additionally, there are indirect and induced job creation from the economic benefits identified in the first pillar.





## Included benefits streams:

- BS1. Direct job saving and creation from preserving offshore platform operation
- BS2. Indirect and induced job creation from economic value creation



# 1 – Curtailment reduction can result in largest benefits but modelling other streams as equally important

## Benefit stream description

|   |   |
|---|---|
|    | <b>1.1. Curtailment reduction</b><br><br>In 2023, a quarter of UK's offshore wind production has been curtailed. Better offshore coordination between countries and power & gas systems can help reduce this loss.                                  |
|    | <b>1.2. Energy transmission losses reduction</b><br><br>In 2022, the UK's electricity losses amounted to ~ 25 TWh. A hub approach can centralise energy flow from offshore to the shore and transfer some energy in gas form, thus reducing losses. |
|    | <b>1.3. Infrastructure optimisation savings</b><br><br>Offshore energy hubs can also optimize the amount of offshore infrastructure used, both transmission and platform.   |
|  | <b>1.4. Avoided cost of assets decommissioning</b><br><br>By reusing existing North Sea energy assets, the energy hub could remove the need for costly decommissioning work   |



## Modelling approach

|  |
|--|
| The data on the exact amount of electricity that is being curtailed per specific cluster of offshore turbines is taken from previous studies and hubs in different geographies. The amount of electricity that is being curtailed is then assumed to be used for hydrogen production in the hub, taking into account losses associated with electrolyzers. The amount of hydrogen produced is then multiplied by the green hydrogen wholesale price in the UK in 2023. |
| Depending on the connection type, the hub concept assumes that now there are less connections required to the shore as there is a bigger and centralised flow of electricity from the hub. Losses from one large connection are subtracted from a sum of losses from smaller connections and then the electricity loss per annum is multiplied by average electricity wholesale price in the UK in 2023.   |
| Currently, the connection sizing is not optimal, where the hub concept can result in better sizing through the connection of multiple wind clusters and collocation of batteries, enabling a continuous flow and higher load factor. The amount of infrastructure for the hub concept is calculated by assuming 100% load factor, subtracted from existing infrastructure, then multiplied by HVDC/HVAC offshore connection cost per specific distance.                |
| The decommissioning cost for each O&G platform is estimated using North Sea Transition Authority UKCS Decommissioning 2022 where the total forecasted figure for a specific timeframe is then divided by the number of platforms / wells considered, providing a cost per unit. This cost per unit is incorporated in the analysis by adding this as CAPEX avoided in the decommission year of the platform considered.  |

## 2 – Environmental savings will result from the indirect CO<sub>2</sub> emission reduction linked to energy production optimisation



### Benefit stream description



#### 2.1. Indirect CO<sub>2</sub> emission reduction from additional green energy production (linked to avoided curtailment)

Reducing the share of electricity curtailed by offshore wind will enable greater green energy in GB's energy mix. This is likely to reduce the carbon intensity of final energy use for GB consumers.



### Modelling approach

The amount of electricity curtailment reduction in the offshore energy hub concept versus the counterfactual (radial design with onshore H2 production) can be assumed to have replaced either the average grid carbon intensity or direct natural gas use. To calculate the indirect CO<sub>2</sub> emission reduction benefits, we need to multiply the volume of electricity non-curtailed in the hub scenario by the difference between the carbon emissions of offshore wind production and the average grid carbon intensity or natural gas. This calculation can be based on the following equation:

$$\text{CO}_2 \text{ reduction} = (\text{MWh}_{\text{electricity non-curtailed}} * ((\text{CO}_2/\text{MWh})_{\text{offshore wind}} - (\text{CO}_2/\text{MWh})_{\text{grid CO}_2 \text{ intensity}}))$$



#### 2.2. Indirect CO<sub>2</sub> emission reduction from additional green energy delivered (link to reduced energy transmission losses)

Reducing the volume of energy loss during transmission between producers and consumers can also reduce the carbon intensity of final energy use for GB consumers.



Equally, the same approach applies to grid loss reduction. We will apply a carbon differential to the volume of energy saved from energy transmission losses in the offshore energy hub concept versus the counterfactual (radial design with onshore H2 production). This calculation can be based on the following equation:

$$\text{CO}_2 \text{ reduction} = (\text{MWh}_{\text{grid losses reduction}} * ((\text{CO}_2/\text{MWh})_{\text{offshore wind}} - (\text{CO}_2/\text{MWh})_{\text{grid CO}_2 \text{ intensity}}))$$



# 3 – Offshore energy hubs will help maintain thousands of offshore energy’s jobs and skills, as well as create new ones

## Benefit stream description



**3.1. Direct job saving and creation from preserving offshore platform operation**

In 2021, there have been just over 200,000 people employed by the offshore oil & gas industry in the UK. All these jobs and skills are at risk of being lost unless they can be transferred to other offshore activities.



## Modelling approach

We will assume that the number of jobs employed by the offshore O&G industry in the UK is going to reduce proportionally with UKCS O&G production reduction. We will use a ratio of people employed for the construction / repurposing and operation of offshore energy hubs to calculate the expected number of jobs saved and compare it to a counterfactual of offshore wind with a radial design.



**3.2. Indirect and induced job creation from economic value creation**

Developing new offshore energy hubs will be more costly in capital terms, while we expect operational system-saving returns. The additional capital required for the development of offshore energy hubs will attract significant new investment in the UK economy resulting in indirect and induced job creation alongside the offshore energy value chain



We will calculate the CAPEX differential between an offshore energy hub and its counterfactual. From this additional CAPEX, we will calculate the indirect and induced job creation using industry-recognised conversion factors.

# Look NorthH2 has other important non-quantifiable economic, social and environmental benefits

|   |   |  |
|---|---|--|
| 1 | <b>Creation of new revenue streams for offshore wind developers</b>                     | Offshore Energy Hubs can provide additional revenue streams for offshore wind developers through power-to-hydrogen, as well as the potential to export energy to Europe.   |
| 2 | <b>Indirect CO<sub>2</sub> saving from accelerated offshore wind development</b>        | Additional revenue streams for offshore wind projects could accelerate the pace and scale of such developments by strengthening developers' business cases. This could help GB increase its renewable capacity at a quicker pace.        |
| 3 | <b>Reduced wholesale price volatility protecting vulnerable customers</b>               | Increased supply-side flexibility for offshore wind developers could help significantly reduce wholesale price volatility. Thus, reducing peak energy prices that particularly impact vulnerable consumers.                              |
| 4 | <b>Increased energy security and resiliency</b>   | Both hydrogen storage and interconnectors are key components of the long-term British energy security strategy. By integrating both in a single concept, offshore energy hubs can greatly improve GB energy security.                    |
| 5 | <b>Biodiversity impact reduction</b>  | The development of offshore infrastructure is more costly financially, but often less environmentally and politically challenging. There are likely to be greater biodiversity benefits from replacing onshore with offshore development |
| 5 | <b>Greater North Sea system coordination and planning with other North Sea partners</b> | Offshore energy hubs will require coordinated planning with other North Sea partners. In doing so, they will also create greater political ties with GB partners, with shared offshore energy planning and operation.                    |

# CAPEX is likely to drive the costs for Look NorthH2 as its development would require large upfront investments

## Costs

The direct costs of the project can be estimated through an estimation of **capital expenditures (CAPEX)** and **operational expenditures (OPEX)**.

- CAPEX includes the costs of the initial investment (e.g. offshore wind turbines, electrolyzers, cables) and, if applicable, replacement costs.
- OPEX includes the costs to operate and maintain the new project, such as labour costs, materials, fuel, energy and other consumables. Many different sources can be used as input for estimating the costs in the factual and counterfactual based on previous CBA studies.

## CAPEX (£)

### Example of variable influencing CAPEX:

- Offshore wind capacity
- Type of offshore wind (floating vs fixed)
- Type of platform (repurposed O&G platform, new built floating, new built fixed etc..)
- Electrolyser type and capacity (PEM, AEL etc..)
- Transmission cable (HVDC, HVAC)
- Pipeline dimension (16" vs 48" etc..)
- CO<sub>2</sub> storage capacity
- H<sub>2</sub> storage capacity
- Battery storage capacity
- Desalination plants

**Sensitivity**

## OPEX (£/MWh)

OPEX includes all fixed and variable costs associated with operating and maintaining all listed CAPEX components above.

- **Fixed OPEX** costs relate to the cost of asset maintenance. Offshore wind turbines and storage facilities are likely to represent the majority of these costs.
- **Variable OPEX** relates to the cost of operating assets. For example, at times with low or no wind outputs but low electricity costs on the wholesale market, electricity can be imported to run electrolyzers, and the CO<sub>2</sub> injection, thus resulting in variable costs.



# The cost streams are going to be modelled by considering both CAPEX and OPEX costs until 2050 Net Zero target and beyond

## Cost stream description



### C1. Platform and storage costs

These costs include platform construction or repurposing, hydrogen storage, CO<sub>2</sub> injection platform and storage.



### C2. Energy generation costs

These are costs related to the asset-producing energy, in this case, wind turbines and electrolyzers, as well as desalinization plants (this would largely depend on electrolyser type)



### C3. Energy transmission and losses

These are costs associated with the transport of both electricity and hydrogen, therefore accounting for electricity cables and hydrogen transmission, as well as energy losses from these assets. These costs would be largely driven by distance



### C4. Additional costs

Additional costs are dependent of configuration chosen and are represented in a form of OPEX as they are mainly driven by electricity that would need to be imported from shore on days with no wind



## Modelling approach

Costs are modelled both as CAPEX and OPEX, as therefore O&M costs associated with each of the components. Most of the costs is embedded in a form of CAPEX from the start of the hub's construction year. OPEX costs are added on an annual basis starting from first operational year. Each of the cost components is dependent on the production capacity chosen.

The cost assumptions for offshore wind turbines and electrolyzers will be the same in all scenarios. However, the operating expense (OPEX) costs will differ between scenarios. This is because in the hub concept, the assets will have higher operational times due to higher load factors, which will drive up the O&M costs. The use of a specific type of electrolyser can avoid the additional CAPEX and OPEX costs associated with desalinisation plants. type of electrolyser is used.

The costs associated with electricity cables and hydrogen transmission will include both CAPEX and OPEX costs. The costs will mainly depend on the connection capacity, measured in MW, as well as the distance. In the case of electricity, whether an HVDC or HVAC connection is used will also depend on the hub's distance from the shore. Additionally, the expected additional loss on energy transmission will be accounted for.

This cost will greatly vary based on the amount of electricity imported to the hub to run its activities (CO<sub>2</sub> injection and H<sub>2</sub> production mainly) at times when the hub's wind production does not generate sufficient energy to self-sustain the hub at the highest cost-economical level.

# Identification of Look NorthH2's major economic benefit streams is crucial to understanding whether benefits outweigh costs

## CBA approach



1. **Development of the counterfactual:** Supply of green electricity to the shore that helps to decarbonise the grid and produce green hydrogen. CO<sub>2</sub> is being transported offshore.
2. **Development of Look NorthH2 factual:** Higher supply of both electricity and hydrogen to the shore due to improved transportation efficiency and optimised production through avoided curtailment. CO<sub>2</sub> transport & storage is optimised by leveraging the hub's infrastructure.
3. **Identification of:**
  - **Benefit streams (financial)**
  - **Cost streams**
4. **Quantification of anticipated net benefits and scalability:** Factual less the counterfactual for all tested locations.
5. **Sensitivity analysis:** Batteries co-location, hydrogen storage co-location, alternative hydrogen offtakers. desalinisation plant co-location.

## Economic Benefits



**B1. Curtailment reduction:** In the counterfactual a lot of electricity produced by offshore wind is being curtailed. The factual assumes no curtailment of electricity as hydrogen is produced, resulting in a significant revenue stream of green hydrogen.

**B2. Energy transmission losses reduction:** The counterfactual consists of many smaller connections from offshore wind clusters to the shore, resulting in significant electricity losses. The factual proposes to include connections from offshore wind clusters to the hub and a centralised connection from the hub to the shore, reducing the number of connections and losses per unit of electricity transported.

**B3. Infrastructure optimisation savings:** The electricity connections in the counterfactual have relatively low load factors, whereas the factual assumes a continuous flow of electricity, requiring less installed capacity.

**B4. Avoided cost of asset decommissioning:** The counterfactual assumes the closing of offshore O&G platforms, where the factual would use these platforms, resulting in savings on decommissioning.

## Costs



**C1. Infrastructure:** These are costs associated with platform construction, connection to depleted O&G field storage, CO<sub>2</sub> injection unit. In the sensitivities, the cost of battery storage, hydrogen storage, and desalinisation plants is applicable.

**C2. Energy generation:** These are costs related to the asset-producing energy, in this case, wind turbines and electrolyzers. In the sensitivity scenario, the additional cost would be desalinisation plants.

**C3. Energy transmission & losses:** The cost is driven by a need for hydrogen transmission construction / repurposing to deliver the hydrogen to the shore. Also, investment in larger HVDC/HVAC cables to deliver electricity from the hub to the shore.

**C4. Additional:** The cost of imported electricity during times of low / no wind. This cost is not applicable in the sensitivities, if batteries are considered.

# These KPIs must be included in the CBA to provide a sufficient level of insight and assess configurations from different angles

## Net present value (NPV)

**Description:** NPV is the difference between the present value of cash inflows and the present value of cash outflows over a period of time. NPV is used in investment planning to analyse the profitability of a projected investment. NPV is the result of calculations that find the current value of a future stream of payments using the proper discount rate. In general, projects with a positive NPV are worth undertaking.

**The rationale for selection:** NPV is the main KPI that will be used for the comparison of counterfactual vs. factual as it would consider the costs and benefits associated with each configuration and would allow us to directly benchmark the counterfactual vs. factual. It is likely the NPV for each configuration will be positive but the option with the highest value will be the most favorable one.

## Benefit cost ratio (BCR)

**Description:** BCR is an indicator showing the relationship between the relative costs and benefits of a proposed project, expressed in monetary or qualitative terms. If a project has a BCR greater than 1.0, the project is expected to deliver a positive net present value to investors.

**The rationale for selection:** BCR enables a more granular assessment of each configuration than an NPV calculation, by providing more detail on benefits vs. costs. This KPI is more appropriate for justifying the factual rather than counterfactual. For the hub concept, it would be important to understand if all the identified benefits outweigh the associated costs and if the investment is justified.

## Payback period (Breakeven point)

**Description:** The payback period is the length of time it takes to recover the cost of an investment or the length of time an investor needs to reach a breakeven point. Shorter payback periods are more attractive investments, while longer payback periods are less desirable.




**The rationale for selection:** As with all novel concepts involving large investments, the long-term NPV and BCR can be favourable, however, the payback period can be very long, therefore making the investment less attractive as uncertainty increases. Therefore, it is important to consider a payback period for the factual, keeping in mind that it can be longer than the counterfactual considering larger investments required.

### Important to note



The main difference between NPV and BCR is that NPV measures the actual or real net economic benefit of a project. While the BCR provides a ratio of benefits to costs.

# The following sensitivities have been selected to test Look NorthH2 and provide further insights into the potential benefits

|   | Sensitivity Name   | Description    | Rationale   | Level of importance  |
|---|--|---|--|---|
| 1 | Deployment of hydrogen storage in offshore depleted O&G fields | Assessing the impact the co-location of hydrogen storage in the offshore depleted O&G fields would have on the business case of NorthH2 concept. The hydrogen storage would be assumed to be located both onshore and offshore.   | According to multiple studies, depleted O&G fields have the potential to be used as hydrogen storage post 2040. This would potentially allow the hub to have more flexibility and therefore better sizing of production and transmission assets, with less reliance on the imports of electricity during low/no wind days.   | High  |
| 2 | Deployment of battery storage in the hub                       | Assessing the impact that co-location of battery storage in the hub would have on the business case of NorthH2 concept. The battery storage would be located on the platform with a direct connection to the production source.   | In both counterfactual and factual, the electricity is transported via a dedicated connection from the shore during low/no wind days. This limits the hub's electricity flexibility during normal days as well. The co-location of battery storage can result in additional flexibility, fewer connections required, and energy independence.  | High  |
| 3 | Alternative H <sub>2</sub> offtakers                           | Assessing the impact that alternative hydrogen offtakers would have on the business case of NorthH2 concept. Not all of the produced hydrogen is being transported offshore, while a proportion of it being fed to local shipper offtakers, with additional refueling infrastructure added. | In recent years there has been more interest in hydrogen for shipping and therefore due to the offshore location of the hub, it has the potential to serve as a direct refueling station for shippers. This would assume refueling infrastructure to be located within the hub (as well as for ammonia production if there is a supply of nitrogen). This would result in less hydrogen transmission required. | Low   |
| 4 | Need for desalinisation plants                                 | Assessing the impact of using an alternative type of electrolyzers with co-location of desalinisation plants would have on the business case of NorthH2 concept. The type of electrolyser is changed to a more basic configuration (classic AEL, PEM) with desalinisation plants added.     | In both counterfactual and factual, the hydrogen is being supplied via electrolyzers that can run on salt water. With it still being a new concept with low TRL, it is beneficial to have an alternative view where hydrogen is produced via existing electrolyzers that run on pure water, therefore requiring additional desalinisation plants.  | Medium  |

*Note: different location assessment is included in the core CBA & the list of sensitivities is subject to change*

# Thank you

## Contacts

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