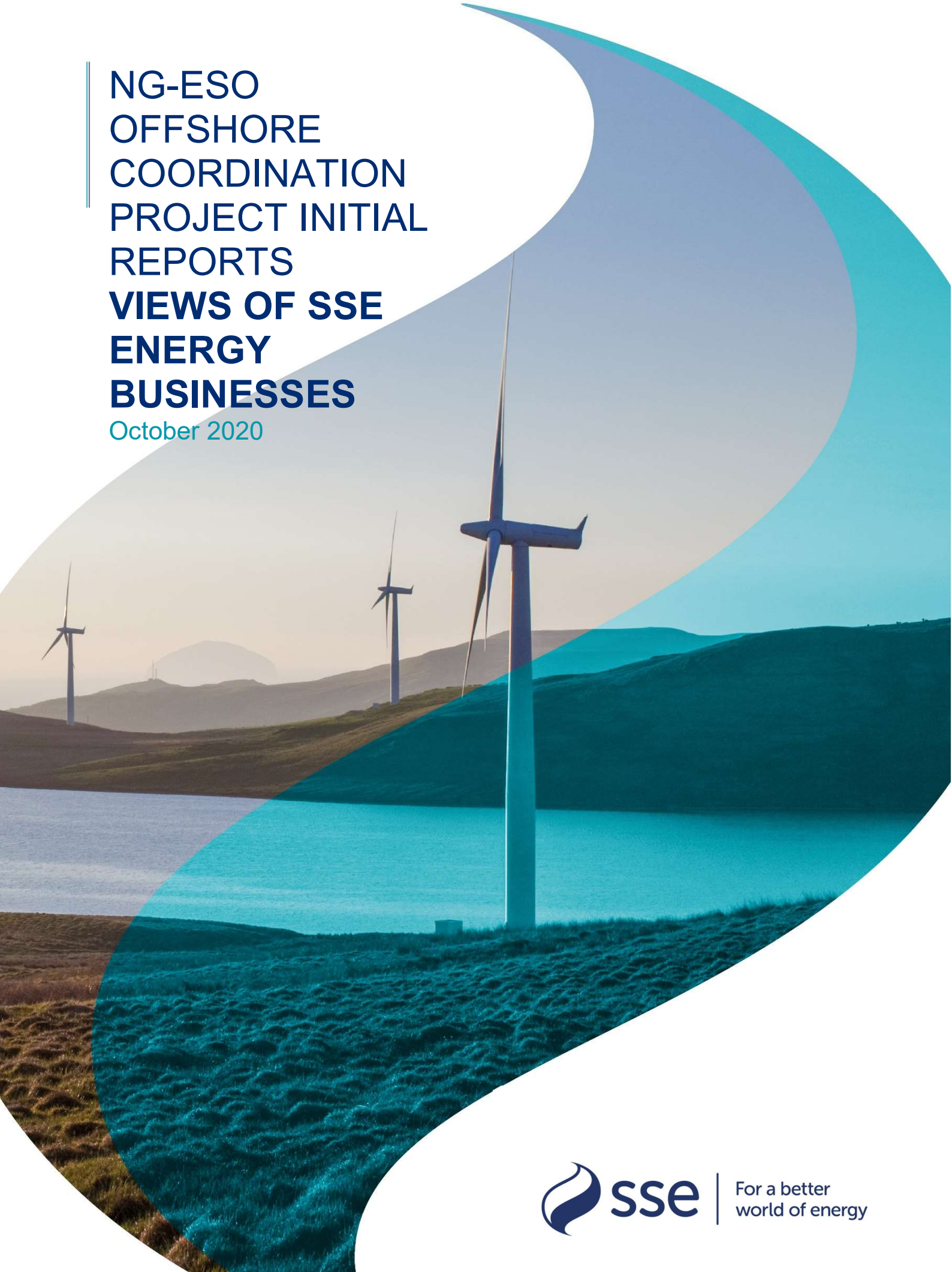
NG-ESO OFFSHORE COORDINATION PROJECT INITIAL REPORTS **VIEWS OF SSE ENERGY BUSINESSES**

October 2020



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ABOUT SSE

This response represents the views of SSE's energy businesses, notably SSE Renewables and SSE Thermal who have interests in transmission-connected generation both onshore and offshore. The main interests in offshore coordination work being undertaken by BEIS, Ofgem and National Grid ESO (NG-ESO) from SSE's energy businesses, relate to SSE Renewables.

SSE also has interests in the transmission of electricity through Scottish and Southern Electricity Networks-Transmission (SSEN-T), which is the owner of the transmission network in the North of Scotland. SSEN-T will be submitting its own response to NG-ESO's consultation.

SSE is committed to be a leading energy company in a net zero world. At the heart of this vision sits SSE Renewables, which has the largest offshore wind development pipeline in the UK and Ireland at over 6GW as well as an operational offshore portfolio of 487MW across two offshore joint venture sites. SSE Renewables has interests in seven offshore wind projects across GB and Ireland.

This response is non-confidential.

OVERVIEW

SSE welcomes the initial reports from the NG-ESO's offshore transmission coordination project, and the contribution it will make to informing the necessary discussion on the need for greater coordination of offshore electricity transmission, which will be required for the UK to deliver its net zero commitments cost effectively. The importance of this work is outlined by the initiation of the Offshore Transmission Network Review (OTNR) led by BEIS and Ofgem.

Whilst a point-to-point approach to offshore transmission as helped the UK deploy significant volumes of offshore wind to date, SSE views that a framework which enables longer term planning as in other parts of Europe, would enable the most cost effective, least disruptive and timely delivery of an offshore transmission network to meet UK offshore wind ambitions. Without change, the UK is at risk of being left behind by innovative system-wide approaches to offshore wind deployment being taken in Denmark, Germany and the Netherlands, and assisted by the European Commission. Actions taken by NG-ESO and others under the OTNR should be coordinated with the EU's Offshore Renewable Energy Strategy due next month, alongside continued participation as part of the North Seas Energy Cooperation Agreement.

SSE views that the UK should aim to ensure that the **GB electricity network is able to accommodate at least 75GW of offshore wind by 2040**, with **onshore grid connections focussed around beachhead hubs** to minimise local electricity transmission infrastructure concerns.

Whilst it is right that NG-ESO looks at the most cost-effective deployment of the transmission network in GB, it is important the **charging regime for allocation of the costs of the transmission system is also considered to the enable the real-world deployment of this approach**.

The current Transmission Network Use of System (TNUoS) charging regime is set up to the incentivise the incremental growth of the transmission network by encouraging generation to locate closer to centres of demand and where there is available. For the transformational change to the transmission system that connecting 75GW of offshore wind and above will bring, **the incremental charging approach under TNUoS is also no longer fit for purpose**, and requires review as part of the OTNR, alongside offshore transmission connections, seabed leasing and electricity market design to ensure net zero can be met cost effectively. This should be considered within the next phase of NG-ESO's work, including the impacts onshore generation, which are facing large and unpredictable rises in TNUoS, which will impact life extension and repowering decisions as increasing volumes of wind generation comes to the end of RO/CfD support from the late 2020s.

For consideration on near term actions, given the time taken to develop and construct an offshore windfarm can be between 5-10 years, an important part for the next phase of NG-ESO's work will be to map out all the processes relating to connections that will need to change and by when.

This will need to work backwards from 2050 in order that projects can move forward without being held back by particular processes (e.g. NOA) necessary for the windfarm's grid connection.

It will also be important to ensure that there is a smooth transition from the existing developer-led OFTO regime to a new regulatory design to ensure that there are no delays in bringing offshore wind capacity online. In this regard, projects ‘in flight’ will need to be carefully managed to ensure that any interim regulatory uncertainty does not jeopardise efficient delivery of generation capacity and associated connections.

HOLISTIC APPROACH TO OFFSHORE TRANSMISSION

Q1. Do you agree with our assessment of the key technology and system risk barriers coming from the Holistic Approach to Offshore Transmission Planning Report?

SSE supports the conclusion that the predominant form of offshore transmission will be HVDC based given the technology readiness level of alternatives and the benefits HVDC offers in terms of flexibility of landing points.

The HVDC technology to achieve the capacity goals of 2030 is already available, with the barriers to implementation of shared infrastructure being more related to the regulatory framework that prevents anticipatory investment.

Beyond 2030, incorporating higher volumes of offshore capacity is likely to require a move to multi-terminal systems. The report focuses on HVDC circuit breakers as a critical technology, but future work should look at interoperability challenges of multiple vendors on the same HVDC system, particularly the ability to have a mix of different vendor's technology within the same HVDC system, and so allow for future expansion without being restricted to a single HVDC vendor. Consideration should be given to the development of common European standards to assist this.

Q2. Do you have any proposals on how to most effectively bring the technology to market for when needed?

The challenge for GB is how to incentivise development of the necessary HVDC technology whilst reducing its costs. As with other low carbon technologies, there is a need for upfront subsidy to reduce the costs of a technology which would have benefits globally. A coordinated European approach would be beneficial in sharing the initial costs to develop HVDC technology, with a balance to be struck between the cost and benefits to UK plc of early support from the UK Government.

The cost of offshore wind has been reduced by repeated competitive tendering rounds, and this approach could prove a basis for developing the necessary HVDC technologies for offshore applications, reducing risks for technology developers of a long term market for their products. Having a clear target of the amount of HVDC infrastructure that needs to be procured, within the UK or collaboratively across north west Europe, would give HVDC vendors a firm indication of the size of the market which would encourage them to invest in the R&D required to develop the technology.

Q3. Do you have any additional evidence to inform the assessment we have made?

NG-ESO should consider all outputs from the recently concluded PROMOTioN project (PROgress on Meshed HVDC Offshore Transmission Networks).

Q4. Do you have any further feedback on the report?

Whilst we note that the report only highlights a Grid Code review as being essential for implementation of the integrated approach, it is likely that upon further scrutiny further significant updates to codes (in particular the GB Grid Code, CUSC, SQSS) are likely to be required to implement an offshore transmission system. The current code change governance procedures are unlikely to be capable of coherently managing the degree and volume of change that will be required given that they are struggling to keep up with the volume of many much smaller changes currently ongoing.

Any changes being made to the Grid Code should align with changes the EU network codes to ensure that HVDC vendors are not required to manufacturer HVDC equipment specific for the GB market.

Whilst the holistic report makes mention of the first offshore windfarms to produce hydrogen post 2032, it assumes that such windfarms will not be electrically connected to the GB system. This may not develop in such a binary approach in the real-world, with clusters of offshore wind hubs potentially sharing both electricity and hydrogen onshore connections to increase the utilisation of the available infrastructure.

The incentives for developing electricity and/or hydrogen onshore connections, will need to be fully considered as it could lead to sub-optimal onshoring of energy from offshore wind hubs. If the incentives are not set considering a long-term, whole systems approach then hydrogen production may be encouraged in areas where there is not demand, based on decisions being driven by locational signals to avoid reinforcement of the electricity transmission network. More strategic decisions on the electricity and hydrogen transmission infrastructure are required rather than incremental price signals.

Further study should consider alternative deployments of offshore wind capacity across the UK based on a comprehensive assessment of the UK's potential offshore wind resource to test cost-effective transmission network deployment and identify the least regret options. The value provided by a geographic diversity of the offshore wind resource should be included in this consideration.

Whilst the report rightly considers interconnection with Continental Europe, both directly and through offshore wind clusters, the next phase of the work should also consider greater interconnection with the Single Electricity Market (SEM) between Northern Ireland and Ireland. Ireland and Northern Ireland will have access to significant wind resources beyond their own demand, which could be used to cost effectively provide electricity across NW Europe, transmitted through GB. Considering a coordinated approach to transmission across the UK and Ireland could highlight opportunities for the cost-effective delivery of net zero across both countries, whilst improving the resilience of both energy systems.

COST BENEFIT ANALYSIS

Q1. Do you agree with our assessment of the costs and benefits?

The operational costs have significant uncertainties. There isn't yet adequate experience of the costs of operating HVDC equipment in harsh offshore environments so not sure how certain we can be on the value of cost savings (or even If there will be cost savings) against radial AC connections.

Q5. Where do you see value for further work to build on and test these findings? Either from the proposed list or beyond?

As acknowledged in the report, an assessment of the benefits of an integrated solution assumes that HVDC circuit breakers progress to commercial use in Europe by 2030. Given uncertainty around this factor, further assessment of the cost impact of alternative approaches, if HVDC breakers are not widely utilised in the offshore grid development at the early stages, would be beneficial.

The CBA is not clear on how it has assessed the cost of the onshore reinforcement needed to transmit the offshore power (ref 3.6.3 of CBA) to the load centres within GB. The volumes of power that will need to be integrated are likely to exceed the capacity of even the largest double circuits overhead lines. Experience with the Beauly-Denny transmission line in Scotland shows that where reinforcement requires the construction of new overhead lines many years can pass with applications in planning, so onshore reinforcement could well become the limiting factor for integrating new offshore wind into the GB system.

One solution which does not appear to have been considered could be to bring offshore HVDC connections much further inland by following the path of certain large rivers, taking advantage of low losses and flexibility of HVDC converter station location. If the environmental challenges of laying cables in tidal rivers can be overcome then this could allow direct connection into key Main Interconnected Transmission System (MITS) nodes with high export capacity, thereby both avoiding or significantly reducing the cost of onshore AC reinforcement, and/or allowing much earlier connections and in particular siting HVDC converter stations away from scenic coastal areas where obtaining the planning permission is likely to be more difficult.

Examples of highly interconnected MITS nodes in locations close to such rivers are:

- Dee/Mersey: Connah's Quay 400 KV; Fiddlers Ferry 275 kV.
- Trent: Keadby 400kV; West Burton 400 kV; Cottam 400 kV; Staythorpe 400 kV.
- Thames: Littlebrook 400 kV; West Thurrock 400 KV; Tilbury 400 KV.

However, under the existing transmission development regime, a developer taking a forward-looking approach would be exposed to the extra cost of the longer OFTO connection even though it results in avoided or deferred onshore AC reinforcement costs (that would otherwise be

socialised) and a much lower impact on coastal communities. These examples illustrate how the network connection and charging regime needs to be updated to incentivise not only the location on the system but the degree to which a connection avoids costs or reduces impacts on stakeholders, particularly coastal communities.

More generally how the costs of this transmission infrastructure will be allocated in a way that enables net zero to be delivered at lowest cost. The current transmission charging regime is set up to incentivise the incremental development of the GB transmission network, when transformational change is required.

Ultimately the costs of the transmission network are paid by the end consumer, whether through demand or indirectly through generator transmission charges and disincentivising development of offshore wind in the areas of greatest resource could lead to increased costs and a sub-optimal network. Greater harmonisation on transmission charges with connected markets will become increasingly important as greater interconnection comes online, as generator transmission charges are lower or non-existent in most connected markets (Belgium; France; Denmark; Germany; and the Netherlands).

Within this, significant offshore wind deployment could significantly change the TNUoS costs for existing onshore generation. Not only could an increase in TNUoS in areas of high volumes of offshore wind adversely impact new onshore generation decisions which are driven independently by differential CfD pots, but it could also impact existing onshore generation coming to the end of RO/CfD support towards the end of the 2020s, as they face decisions on life extensions or repowering. Perversely, TNUoS changes outwith the control of generators control could mean that new low carbon generation prematurely closes existing low carbon generation. As part of a comprehensive review of TNUoS, the stability of network charges and its impact on operational and investment decisions of generation need to be considered.

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REVIEW OF OFFSHORE CONNECTION PROCESS

Q1. Do you think that if the areas we are highlighting were improved, that the ability to coordinate projects would be significantly increased?

We are concerned about the risk of projects that are 'in flight' being delayed by inclusion into a regional CION process. It is essential that such projects are not delayed and where benefit could be seen from sharing of infrastructure that this is only taken further if it could allow an earlier connection date.

We note a proposal in the report to formalise the roles of developers in the System Operator-Transmission Owner Code (STC) to allow developers a more direct involvement in the CION process and control over the transmission works they are reliant on. Given that all offshore wind projects to date in the UK were successfully built under the developer-led OFTO option, it will be paramount to ensure that developers continue to play an important role in the grid development process to avoid project delays.

Q2. Do you think we have missed anything in our offshore connections review that would add value and increase coordination?

There appears to be a disconnect with NG-ESO regarding the current application process for Scotwind and Round 4 (R4) with the NG-ESO connections team unaware of the potential for a regional CION process. Clarity would be welcome on if the regional CION process is aimed at the R4 auctions.

Currently, developers are competing with each other for seabed leases, CfDs, Transmission Entry Capacity (TEC) etc, this doesn't lend itself to the collaborative approach that would be required for a coordinated offshore connection process. To get to the levels of offshore wind to deliver on net zero, a coordinated approach would be required by a range of actors and for their processes including NG-ESO, BEIS, Ofgem, the Devolved Administrations, the Crown Estates, the Environmental regulators, as well as equivalent bodies in connected markets.

For Phase 2, NG-ESO could include a review of how other countries are considering a system-wide approach to integrating offshore wind and the benefits that could be obtained by having large scale leasing rounds that include a grid connection.

The UK is at risk of being left behind by innovative system-wide approaches to offshore wind deployment being taken in Denmark, Germany and the Netherlands, and assisted by the European Commission.