Getting GB electricity market design right

Changes that support a greener future system

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How renewables can best serve the future energy system

The UK is at a crucial point on its journey to net-zero. Time is running out for creating the frameworks that will enable our ambitious targets to 2035 and 2050. The UK story so far has been marked by successes in growing our renewables portfolio – from supplying just 3% of the UK's electricity demand in 2000, to supplying over 40% in 2023, with wind making the second largest contribution after gas. However, the scaling up needed in the next leg of the journey to net-zero is unlike anything seen before.

Achieving this scaling up is a huge and exciting challenge. Changes are needed to the electricity system and the design of the market that supports it. The system was not designed for a renewables world; it desperately needs build out of network infrastructure to transport new renewable electricity to where and when it is needed. We have not yet unlocked the full flexibility of renewables in order to change where to send electricity in response to the system needs. If we do not solve this challenge we will continue to rely very heavily on gas to meet our energy needs, which exposes us to volatile global markets.

In this paper, we propose three connected changes to the market arrangements which would support the future net-zero system: First, by reforming the Contract for Difference (CfD) instrument to support the future system; second, by stimulating new infrastructure assets like storage and electrolysis that are needed for system integration; and third, encouraging new ways for renewable assets to serve a high penetration system. These three changes can support the operation of the system, but financial investment in the network remains critical. No amount of change to market arrangements will be enough to avoid this requirement, but the three connected changes are supporting actions we can take now while we collaborate to drive the networks to catch up. We believe these will place renewables at the heart of Britain's future electricity system and will be most effective at delivering long-term, sustainable system change.

Duncan Clark
Head of Ørsted UK and Ireland

Three connected changes to support a greener future energy system

Reform the Contract for Difference (CfD)

With the right reforms targeting the right technologies, the CfD will:

- continue to draw support from investors as it is a proven, attractive instrument
- encourage developers and investors to commit to renewables that respond to the needs of the electricity system
- pass on the value of renewables to consumers.

Unlock integrated, flexible energy solutions

If renewables are to support the requirements of the system, they will need greater access to alternative routes for sending their generated electricity, such as energy storage systems and electrolysers.

Encourage new ways for renewables to serve the future energy system

We need new ways of encouraging different operations from renewables across the electricity system, but trying to achieve this by varying market prices by location is slow, disruptive, and the overall benefits are highly questionable.

What are the electricity system challenges that mean change is needed?

Overview of the challenges

Lack of network investment has contributed to a locational challenge

Investment in the grid has not kept pace with the significant growth of renewables over the last two decades. It is critical that new investments are made, but in the meantime this requires changes to how generators plan for growth opportunities and operate. However, drastic proposals such as the introduction of nodal pricing should not be considered part of the solution.

We have not yet unlocked the full flexibility of low carbon solutions

We can alleviate challenges to the electricity system by embracing flexibility solutions such as storage, batteries and hydrogen. However, there remain barriers to unlocking the range of flexibility.

Gas sets the electricity price

While we continue to rely on gas for meeting our energy needs, we remain exposed to volatile global markets that undermine the security of supply that can keep customer bills low.

Overview of changes needed

1 Reform the Contract for Difference (CfD)

Why make this change?

The Contract for Difference (CfD) is a well-known and understood instrument with a great track record of delivering for generators, investors and consumers. **Changes to future CfD contracts are easier to implement than radical, parallel market alternatives, and can create the enablers to making renewable generators more responsive to the needs of the system**. A 'deemed' CfD, where payments are no longer based solely on electricity generated, is a good starting point for considering reforms.

What challenges does this solve and how does it do so?

Challenge	Solution
The competitive cost of renewables should be passed through to consumers in the best way.	**Extend existing schemes** as a lower risk option than introducing new approaches, such as a green power pool. This means: • allowing a greater number of renewable projects to access CfDs at sustainable prices; • extending the CfD term from 15 years to a longer timeframe, to provide benefit to consumers for as long as possible.
Generators need to change how they operate to support the system. CfDs currently provide limited incentives to operate a renewable generator flexibly.	Carefully consider **reforms that partially decouple CfD payments from output**, so the system is supported by more responsive renewable generators. Collaboration between industry and policy makers is needed to ensure the detailed design is fit for purpose.
Investor confidence must be maintained to ensure more renewable assets are deployed.	**Maintain investor confidence as the primary success factor of the CfD.** Avoid CfD reforms that introduce locational variations – **locational decisions should happen earlier in the development process** at the point of seabed/land leasing.

2 Unlock integrated, flexible energy solutions

Why make this change?

If CfD reform takes place in isolation, there may still be no way for CfD assets to respond to the needs of the system. It therefore becomes imperative to facilitate a market characterised by more integrated, flexible business models.

What challenges does this solve and how does it do so?

Challenge	Solution
Generation technologies have untapped potential to provide flexibility and system services but are held back by barriers.	Identify and **remove barriers, including regulations around energy trading, charging, and connection.**
We have to access as much flexibility as possible.	**Promote integrated project models**, including storage and electrolysers, in supporting local and national system operations.

3 Encourage new ways for renewables to serve the future energy system

Why make this change?

Once the above reforms are in place, renewable generators supported by CfDs will be better able to respond to the needs of the system, but there are different ways to encourage that response. These should be compared and assessed, and it is important to make sure that the market is designed in a way that uses the right incentives. In making the assessment, it is crucial that we do not create new, unexpected risks for existing investors and generators which cannot be managed.

What challenges does this solve and how does it do so?

Challenge	Solution
Balancing the system is a more complex task, and one that is more locational in nature. Generators need to change how they operate to support the system.	Identify assessment criteria and use these to **compare the different options for encouraging renewables to change operations.**
Deciding whether to solve the system challenge with a market-based solution.	**Rule out nodal pricing** and employ caution when considering less extreme forms of Locational Marginal Pricing (LMP), i.e. zonal pricing.
Investor confidence must be maintained by implementing only changes that can be managed.	Protect existing investments by implementing **grandfathering** or measures that are voluntary for legacy generators.

Challenges in more detail

Lack of network investment has contributed to a locational challenge

Since 2000, the GB electricity system has undergone some fundamental changes. Renewables have grown to become an established part of the energy mix, industrial demand for electricity across UK has decreased[1] and the level of generation embedded in distribution networks has increased. Investment in the grid has lagged behind these changes, and some transitional measures to support renewable growth have added to this lag[2] and have been allowed to persist for longer than intended.

The net effect for the system operator is that it now has a more complex task to balance the system, and one that is more locational in nature. We need significant investment in the transmission system to handle the even greater future increase in renewable assets needed to reach our net-zero aims. Without this investment, the system operator will have ever greater difficulty in matching supply and demand at specific locations on the network and in managing regional voltage stability. As a result, future growth opportunities will be hampered (or paused) and investments will be delayed (or cancelled) as confidence in the UK market and its operation is challenged.

In the meantime, generators need to change how they operate to support the system. For this reason, some have suggested that this electricity system problem needs a market solution that amounts to having different prices at different locations, an approach known as Locational Marginal Pricing (LMP). This is a drastic overhaul to the current market arrangements and in the most extreme case would give a different price at every node on the system. **This is known as nodal pricing and is a reform that we do not support – it removes investor confidence, creates unexpected risks for existing generators, represents a high-cost transition, and has a highly questionable benefits case** (see appendix for more details).

We have not yet unlocked the full flexibility of low carbon solutions

Integrated solutions offer benefits in a future world where renewable generation dominates but on a system that was not built for it – a system that was designed for centralised, dispatchable (fossil fuel) generation. While we wait for network investment, it is no longer enough to rely solely on transporting electricity around the grid to maintain balance. For this reason, we have to access as much flexibility from generators and consumers as possible. This becomes all the more important as renewable generation with variable output continues to grow.

Currently, some generation technologies have untapped potential to provide flexibility and system services but are held back by barriers.

[1] Compared to total electricity supplied in 2005, UK's demand for electricity in 2022 was 21% lower DUKES 2023 Chapter 5 (publishing.service.gov.uk)
[2] The 'Connect and Manage' regime is the prime example of transitional measures intended to accelerate renewable development, but were not accompanied by regulatory change to help build out transmission infrastructure in parallel.

For example, CfDs provide very limited incentives[3] to operate an asset flexibly. Specifically, the need to forgo subsidies to participate in some flexibility markets (e.g. low frequency service) makes it harder to participate in those markets and forces the generator to make a case-by-case economic decision. **The inability to participate complementarily in electricity and flexibility markets means that the generator is limited in supporting wider system integration – it means the system is not getting the most value out of those assets.**

There is potential to take action in other areas that would promote integrated models. Network charging regimes could be made more supportive of integrated solutions; the combined use of CfDs and private wires could be encouraged further; and industry codes can be updated to reflect the types of integrated assets that are needed.

Gas sets the electricity price

Britain's energy security depends on global, volatile gas markets beyond our control. This can create sudden price spikes that push up customer bills, unless other interventions are made[4]. The problem is not that the wholesale market is bad for consumers, in fact the opposite is true – the principles of "marginal pricing" have ensured effective operation of the electricity system.

Rather the problem is the system's reliance on gas, and we need to break this link in the long term by replacing gas-fired generation with more renewables. But a second challenge in the short term, while gas is still relied upon to balance the system, is to make sure that the low cost of renewables is passed through to consumers in the best way possible.

In meeting the second challenge, one option is to encourage more renewable and low carbon generators to move onto fixed price, long term contracts such as CfDs. These already exist and break the link between wholesale market volatility and the prices passed to consumers. By design they define how much risk is shared between generators and consumers, which means that if wholesale prices rise, consumers feel benefits rather than additional costs. They are well known, well understood, and could be reformed to be even more effective at protecting investors and consumers.

Other suggestions are more radical and include setting up a parallel market (e.g a green power pool) where renewable electricity can be bought and sold. This has potential to make it easier for some consumer groups to access cheap renewable electricity, but is a fundamental shift in approach that calls into question the role and function of electricity markets.

[3] More recent versions of the CfD include a basic incentive, where assets are encouraged not to generate if market prices are negative.
[4] By way of example, in 2022 gas prices spiked – that led to a similar spike in electricity prices, which in turn pushed up customer bills. Ultimately, this led to the introduction of the Electricity Generator Levy (EGL) and the Oil & Gas Energy Profits Levy (EPL) to protect consumers.

Changes needed in more detail

Before addressing the connected changes, there is one principle that needs to be kept in mind throughout. To achieve net-zero, GB is going to need huge investments across the energy industry. This could amount to £500 bn in electricity sector investment up until 2050[5], not to mention support for supply chains that enable it. It is therefore imperative that retaining investor confidence remains a core objective and measure of success in all areas. This means avoiding making changes that create new, unexpected risks for existing assets, as well as building a future investment environment that is internationally attractive.

1. Reform the Contract for Difference (CfD)

The CfD has been very successful in securing investment for renewables and growing the industry. While it has been successful in getting GWs of capacity built, the CfD regime has also been successful in getting GWh of generation to flow onto the electricity system whenever the generation is available.

However, this does not always correlate with when and where the electricity system needs it. This has potential to get worse, but designing a future CfD that aims to unlock renewable flexibility can address the issue.

The CfD must remain an attractive instrument to investors throughout any reforms. This includes making sure that the CfD remains free from locational investment signals – developers start to make investment decisions many years ahead of CfD auctions, and there is a risk of incurring significant cost with no consumer benefit if a new investment signal is introduced later in the development cycle.

However, it is possible to make changes to the future CfD design that both maintain investor confidence, and encourage more innovation in flexibility of output. Decoupling payments from outputs has potential to achieve this. In theory this is a simple and elegant approach – investors will still have transparency around how their costs are recovered, but this can be linked to a new measure that frees the generator to change how it operates in response to what the system needs.

There are different ways to achieve this, where payments are based on forecast output or an agreed capability to generate. In such cases, if a generator alters their actual output, this does not incur the cost of lost CfD revenue. That makes it far cheaper to respond to the needs of the system operator, and ultimately reduces the overall cost of balancing the system. However, it requires careful design – methodologies need to be agreed for determining a forecast, measuring lost generation, and verifying data to settle payments.

For this reason, a move towards a decoupled approach would need a collaborative design phase with industry involvement and designs agreed well in advance of investment decisions, with clear rules about how the design will be reviewed in future.

If achieved, there is a strong argument that similar arrangements should be extended as far as possible across the nation's portfolio of renewables. Therefore, there is value in increasing the number of CfDs available in future and extending the term of CfD contracts beyond the current design of 15 years – this maximises the scope for generators to be more responsive to system needs.

[5] UK falling behind in race for clean energy investment - Energy UK (energy-uk.org.uk)

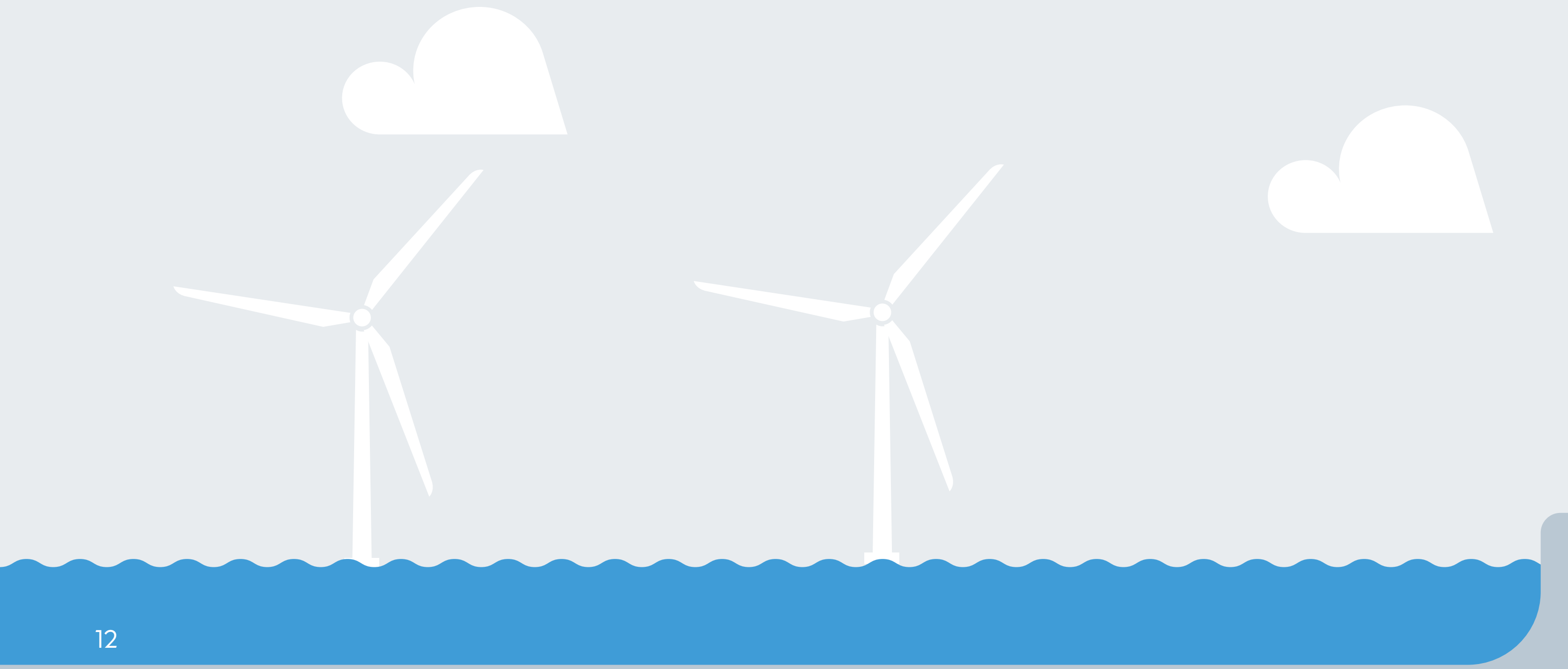
2. Unlock integrated, flexible energy solutions

CfD reform is an enabler for changing how generators operate, but not the only one. Another key enabler is making sure that renewables have access to technologies that can be used in response to the needs of the electricity system. These technologies provide another route for using electricity, such as energy storage or electrolysers. To unlock the full flexibility potential, they need to exist as integrated, complete solutions at a local level because the needs of the system can be very specific to location and arise for a variety of reasons, related to network balancing and maintaining reliable operations.

It is not enough simply to locate these technologies near to generators – they need to have co-optimised operations. For example, there are synergies that exist between having a windfarm and electrolyser in a single integrated solution: electricity can be exported to the transmission network when needed by the system, but in periods of high wind output and low electricity prices the electricity can instead flow to the electrolyser. Not only will this help to address the local needs of the electricity system, it will also help to optimise the system so that less network infrastructure investment is needed overall.

Successful optimisation requires a detailed knowledge of a range of factors that go beyond those needed to balance the electricity system – they could include operational inputs across different markets and communication with different sets of customers. It is only possible to realise the full set of benefits through co-located, co-optimised solutions operated by the asset operator.

To encourage the evolution and deployment of these integrated, co-located models, policy makers need to remove all potential barriers, including planning, grid connection, trading, and technical metering arrangements. CfD rules and industry codes should also be revisited to allow greater scope for private wire and "behind the meter" arrangements, as well as making it easier to trade between the different parts of the integrated solution. There is also a need to encourage continued innovation and exploration of solutions between parties (e.g. effective "pathfinder" projects between asset developer and system operator).



3. Encourage new ways for renewables to serve the future energy system

Only with the changes described will renewables be fully enabled to change the way they operate to support the electricity system. But being enabled is not the same as acting – there still needs to be an incentive to signal how a generator should change how it operates. Finding the right approach will not be easy – it is a contentious topic with advocates for different approaches, including maintaining the status quo. However, there are some meaningful differences between the candidate options. Some assessment criteria are important but not necessarily useful in comparing options (e.g. long term benefit is very important, but based on more assumptions, which make it harder to draw distinctions between options). Therefore, we encourage policy makers to focus on three criteria in particular when assessing different incentives:

- **the set of participants impacted (either mandatorily or voluntarily)**
- **the immediate cost and complexity of transition/change**
- **the potential for unintended consequences.**

Some legacy generators will not be able to respond to the two previous changes described, for example due to CfD eligibility. The first bullet above is particularly important to these generators, as a mandatory approach may well create risks that they are in no position to manage. Therefore, a mandatory approach may be inappropriate, or such generators would need some form of grandfathering as protection.

As discussed in the appendix below, nodal pricing is a highly disruptive change with a questionable benefit case, and therefore should not be implemented. It involves a costly transition, impacts a broad set of participants indiscriminately, and as a major change it has potential for significant unintended consequences. This is true for less extreme forms of LMP too, such as zonal pricing, and therefore we urge caution when considering them.

There are alternative approaches. One is to reform the existing network charges, namely Transmission Use of System (TNUoS) and Distribution Use of System (DUoS) , which already act as zonal incentives. Another is to set up separate markets based on local balancing. In our view, the right solution is far from clear, and could even be a combination of the options available. However, we want to see assessment based on clear criteria as set out above.

Below we have included further details on the candidate options that could be used to encourage how renewables operate:

- **Maintaining the status quo:** If we can achieve the first two changes, renewables may be able to support local system demands on the basis of the existing national priced markets combined with local balancing services. This would avoid the cost of any reform activities, but require a detailed analysis that sufficient benefits would be delivered through the first two changes alone.

- **Further reform to network charging to encourage real time system response:** Network charges have historically encouraged some amount of response to system needs (e.g. responses to Triad warnings), and there is potential to make this stronger. This has benefits of being a change to an existing regime, and theoretically more easily tailored to participant groups (although noting that there is still potential for this to impact legacy assets negatively). The drawback of it being applied outside of markets is that it could create some distortions to those markets. Some difference in scope would need to be addressed – for example interconnectors are not subject to TNUoS, and therefore other tools may be needed alongside such charging reforms (e.g. the system operator using increased countertrading).

- **Alternative local markets:** There is a possibility of keeping a nationally priced wholesale market with parallel local markets for other services. Examples are local constraint markets, and these have potential advantages around addressing specific local issues. However, they must be carefully considered to ensure that there are no barriers to participating for those that are exposed, and that they do not create harmful distortions, such as shifting liquidity between markets or creating gaming opportunities.

- **Zonal LMP:** Implementing locational variations within the market price is a highly dynamic approach, but also indiscriminate as all participants would be exposed by default, including legacy assets who would incur new, unexpected risks. Because of this indiscriminate approach, without the enablers we have described being applied consistently across all assets , it represents a high risk approach where a poorly designed and implemented change could create significant risk and cost to projects. It also involves significant reform to the existing arrangements, as well as a need to assess further impacts.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Appendix – Nodal Pricing

We stated that we are not in favour of nodal pricing. In this appendix we describe more about what nodal pricing is, and the reasons behind why we do not support it.

The GB electricity market operates with one single national price. That means that all electricity consumed receives the same price, irrespective of where it is generated or consumed. However, there are costs and incentives that are locational and act in parallel to the market, and these include the charges paid for using electricity networks, the amount of electricity lost while moving it between locations, and the prices available for helping to balance the system. While the last of these is specific and dynamic, the rest are based on different zones, are set ahead of time, and do not change with the real time needs of the system.

Locational Marginal Pricing (LMP) is a fundamental change in the market structure that would introduce price differences depending on location. As a result, some or all of the locational incentives above could be rolled into the market price rather than acting in parallel. That immediately makes them sharper, in terms of how they change over time, and potentially how they change by location. In terms of changing over time, the market prices change every 30 minutes – that means charges that today are known ahead of time could be removed and replaced by prices that are dynamic, volatile and harder to forecast. This creates new risks and costs that investors would need to manage.

In terms of changing by location, this depends on the version of LMP chosen. LMP can be set up to offer different market prices by price zones. If these zones align with those used for network charging, there might be relatively little change in how generators and consumers experience locational variations in costs and incentives (although noting that temporal variations are more extreme, as noted above). However, in the most extreme case, LMP would give a different price at every point on the system. This is known as nodal pricing and would lead to far greater price differences which would be harder to forecast and manage.

Based on these features, nodal pricing leads to new challenges that would have to be managed, and we do not support it for the reasons below:

- **Harmful to investor confidence:** An overhaul of the existing arrangements creates uncertainty for investors who will have limited information on how the new market will function once implemented. This leads directly to greater uncertainty of the value in investing in new assets in GB. In a globally competitive market for capital looking to invest in renewable energy, GB would become a less attractive market and therefore fewer renewables assets would be deployed and at greater cost.

- **High transition cost:** Moving to a nodal market would be a lengthy process. Based on experience from other markets, implementation takes many years – even up to a decade. In a GB context, there is likely to be a resource constraint around delivering such a change, as this would be one of a suite of simultaneous large scale change programmes to implement. Therefore, there is a good chance that the cost and time for implementing nodal pricing will be underestimated, and in the meantime will create uncertainty for market participants and investors.

- **Questionable benefits case:** The benefits of nodal pricing hinge on it being more efficient – for example, unneeded generation receives a low price rather than being paid to turn off to balance the system. Several recent studies[6] have attempted to quantify this benefit case, and findings show huge divergences with order of magnitude differences between them. In all cases the benefits appear small (as little as ~1% of overall consumer bills); it is clear that the benefits are hard to forecast and highly sensitive to assumptions. Some studies have even suggested that the majority of benefits can be achieved without such an extreme version of LMP as nodal pricing.

- **Little impact on where investments are made:** If nodal pricing aims to change where new assets are built, its scope is necessarily limited. Renewable generators have to locate in sites with ample resources that are feasible from consenting and permitting perspectives too. Defining and then developing sites takes place often many years in advance, after which point developers have no realistic way of re-siting in response to a locational incentive. Offshore wind may be the best example, where locations are defined by The Crown Estate and Crown Estate Scotland many years in advance. Nodal pricing therefore risks simply increasing the costs of making the necessary investments in GB renewables.

- **Limit on how it changes real time operations:** LMP is intended to influence how assets respond to the needs of the system. It means discouraging generators from flowing electricity onto the system if it is already well supplied, for example. In that scenario, the generator would want an alternative route to market (e.g. energy storage, electrolysers). Those alternatives become a key enabler in a nodal market, or else those generators are at risk of not being able to cover their costs. However, building an investment case for those alternatives in such a volatile and opaque setting as a nodal market becomes extremely challenging.

- **Nodal pricing risks missing opportunities to make whole system optimisations:** Nodal pricing relies on vast computations being performed every half hour to determine which power stations to run. It necessitates a system with more centralised control and an operator making those optimisation calculations ahead of time. However some generators will be integrated, for example a windfarm connected to an electrolyser. In this case, the optimal output depends on two systems – electricity and hydrogen. If nodal pricing relies on a central operator, there is potential to miss these optimisations that go beyond the electricity system, but the asset operators themselves are better placed to make the right optimisations based on their knowledge of multiple systems.

[6] These include reports from AFRY, The Energy Policy Research Group, Aurora, FTI Consulting and the University of Strathclyde

About Ørsted

Over the past 30 years, we have established our company as the global leader in offshore wind with 8.2 GW installed capacity. Our ambition is to have installed 30 GW of offshore wind globally by 2030.

We develop, construct, own and operate offshore and onshore wind farms, battery storage and solar projects. We also have a Power-to-X business that provides renewable hydrogen solutions – which can power medium to heavy-duty transport or be used in industry.

Headquartered in Denmark, we operate globally and have projects in the UK, Ireland, Germany, the Netherlands, Taiwan, and the US.

The UK is our largest offshore wind market with 5.6 GW of installed capacity – enough green energy to power over 6 million UK homes a year.

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Ørsted

@OrstedUK

orsted.co.uk

Ørsted
5 Howick Place
London
SW1P 1WG

Tel: +44 (0) 20 7811 5200