UKERC
UK Energy Research Centre

sse

PRINCIPAL PARTNER
UN CLIMATE CHANGE CONFERENCE UK 2021
IN PARTNERSHIP WITH ITALY

# Risk and Investment in Zero-Carbon Electricity Markets

## Implications for policy design

Will Blyth, Robert Gross, Stephen Nash, Malte Jansen, Jamie Rickman and Keith Bell

This discussion paper has been produced to present preliminary findings from ongoing research and engagement activity led by UKERC on the topic of the future of electricity markets. The work involves a variety of stakeholders and UKERC partners. An expert group with representatives from UK Government, Ofgem, the Energy Systems Catapult and Energy UK are helping inform the analysis. The work is part funded by SSE. However UKERC has editorial independence and the authors take full responsibility for errors and omissions. To support development of a zero-carbon electricity market design in the UK to help meet net zero commitments around the world cost effectively, this initial analysis is being published on Science & Innovation Day at COP26.

## Authors

**Will Blyth**, UKERC researcher,
Oxford Energy Associates
**Robert Gross**, UKERC Director
**Stephen Nash**, Kuungana Advisory
**Malte Jansen**, UKERC researcher,
Imperial College London
**Jamie Rickman**, UKERC Researcher,
University College London
**Keith Bell**, UKERC Co-Director,
Strathclyde University

## Reference

This report should be referenced as: Blyth, W., Gross, R., Nash, S., Jansen, M. and Bell, K. 2021. Risk and Investment in Zero-Carbon Electricity Markets: Implications for policy design. UK Energy Research Center.

## About SSE

SSE has the largest renewable electricity portfolio in the UK and Ireland, providing energy needed today while building a better world of energy for tomorrow. It develops, builds, operates and invests in low-carbon electricity infrastructure needed in the transition to net zero, including onshore and offshore wind, hydro power, electricity transmission and distribution grids, and efficient gas, gas with CCS and hydrogen power generation to support a renewables-led energy system, alongside providing energy products and services for businesses.

## About UKERC

The UK Energy Research Centre (UKERC) carries out world-class, interdisciplinary research into sustainable future energy systems.Our whole systems research informs UK policy development and research strategy. UKERC is funded by the UK Research and Innovation, Energy Programme.

UKERC is committed to making all of its publications accessible. We're always looking to improve the accessibility of our publications. If you find any problems or would like further assistance please contact UKERC@ucl.ac.uk

# Part 1: Introduction

At the end of 2020, the UK Prime Minister announced an aspiration to build 40 GW of offshore wind by 2030. With poetic references to the wind that puffed the sails of Drake, Boris Johnson placed offshore wind at the forefront of a 'green industrial revolution.[1]' In October 2021 the UK Net Zero Strategy doubled down on this, reiterating the importance of offshore wind and the key role of a decarbonised power section in meeting net zero aspirations[2].

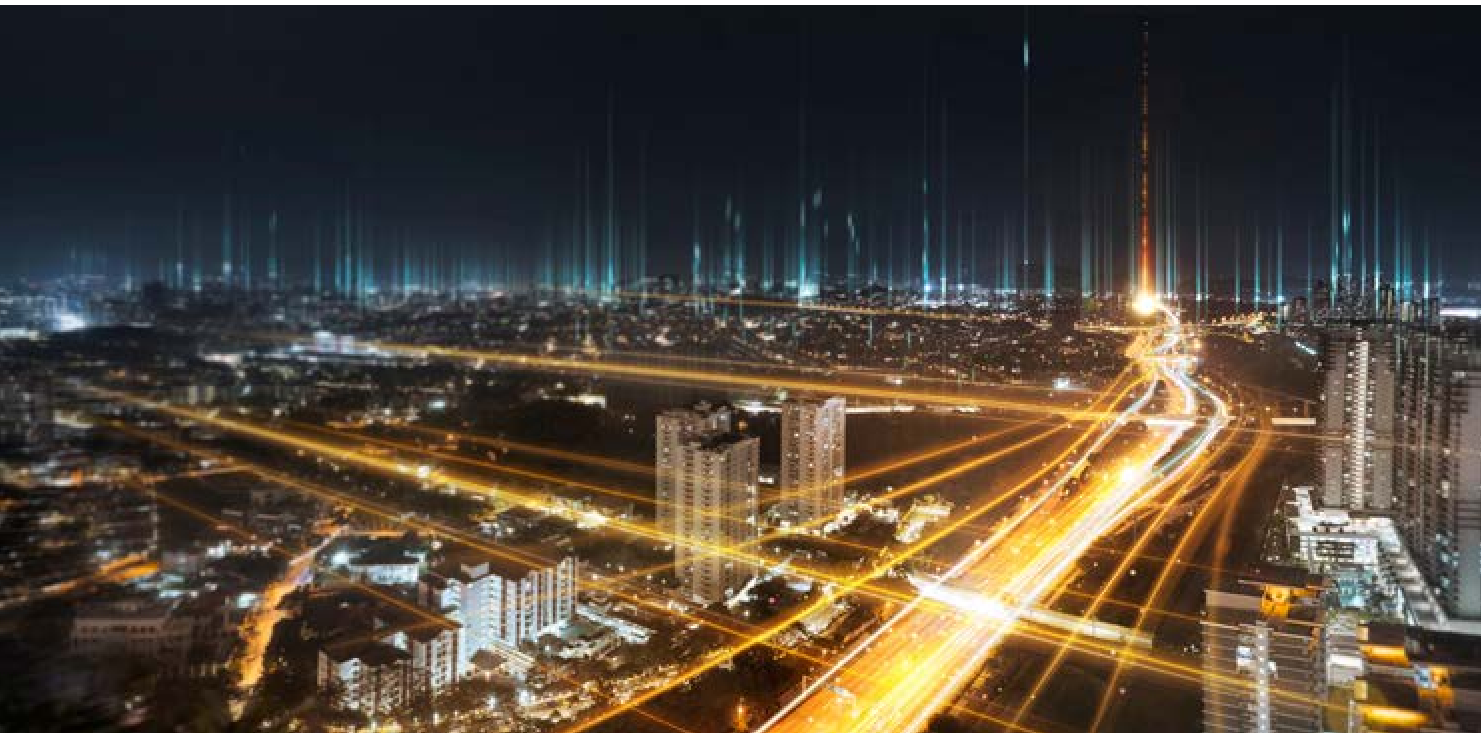
In the last 20 years, Britain has installed around 10 GW of wind around our shores – a remarkable achievement that places the UK at the forefront of sea-based renewable energy and helped drive down costs globally. However, to quadruple the amount of offshore wind in half that time will be no mean feat. To put it mildly, installing 30 GW of new offshore wind in nine years is a significant challenge. It requires amongst other things the mobilisation of something of the order of £60 billion of investment. However, this is just the beginning. Scenarios from National Grid ESO, the Great Britain system operator, put the amount of wind needed for a fully decarbonised system at between 80-110GW by 2040[3] requiring investment of up to £200 billion.

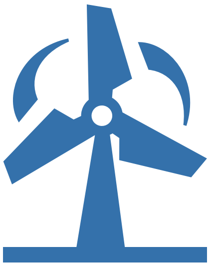
Renewables in general and offshore wind in particular play a substantial role in most recent UK/GB[a] decarbonisation scenarios. The Net Zero Strategy reaffirms the central role of renewables in the decarbonisation of power, noting that in 2035 and 2050 power generation is likely to be 'composed predominantly of' wind and solar.[4] This is because the costs of wind and solar have fallen substantially. There is also a very large potential resource in the UK, particularly offshore.

Policies put in place in 2013 under 'Electricity Market Reform (EMR)' have played a key role in driving cost reduction and deployment.[5] Government backed contracts known as Contracts for Difference, or CfDs, have proved attractive to investors and developers.[6] Whilst prices set through auctions place downward pressure on prices. Renewable energy expansion has continued apace whilst other low carbon options have struggled to become established. Nuclear power and CCS appear to need additional support, or more action by government to de-risk investment.[7]

The scale of renewables expansion needed to meet net zero means the roll-out has scarcely started. Given existing policies appear to be successful in terms of deployment and cost reduction it is somewhat surprising that the Net Zero Strategy also restates a question the government first posed in a Call for Evidence at the beginning of 2021.[8] It reiterates the value of the current policies but also asks if "broader reforms to our market frameworks are needed to unlock the full potential of low carbon technologies to take us to net zero."

[a] Throughout the report we refer to UK climate targets and to Great Britain or GB electricity markets. This is because the electricity market arrangements under discussion apply in GB. Separate arrangements apply in Northern Ireland under the integrated single electricity market for Ireland and Northern Ireland.





**80-110GW wind energy is needed for a fully decarbonised system by 2040**

There are a variety of reasons that the government might wish to review EMR, which is also called for by the Climate Change Committee.[9] Some of the debate is focused on whether government or industry is best placed to make strategic choices about investment. Industry commentators have also raised concerns about the economic viability of wind and solar farms when they reach the end of CfD or previous support schemes, cautioning that existing market structures could result in premature retirement of existing assets as they would be unable to recover their ongoing costs from the market.

Any legislative changes will take time to implement so discussion and analysis of potential policy options needs to proceed apace. In this preliminary paper we focus on a subset of issues in the debate associated with whether, to what extent, and how to increase exposure of low carbon generators to wholesale market price risks. We frame the choice in terms of a simple equation – reducing cost of capital vs providing incentives for system balancing and flexibility.

Part 1 sets the scene, highlighting the advances achieved in renewable deployment and the pivotal role that policies have played thus far. It also highlights the scale of the challenge ahead and asks if policy reform is needed going forward.

Part 2 introduces some of the issues associated with wholesale market price formation as the share of generators with very low marginal costs increases and how this gives rise to a debate about market design and risk allocation.

Part 3 explains a simple and transparent model we have developed to explore how uncertainty about the power generation system of the future affects investment risk. We then explore in simplified terms how different incentive designs mitigate or exacerbate upside or downside risks, and therefore affect the cost of capital. Our purpose is not to argue for any particular policy, but rather to quantify in a simple and transparent way the relationship between exposure to wholesale market price risks, cost of capital and costs of generation. Future work will explore wider system costs.

Part 4 includes conclusions and implications for policy.

# Part 2: Background

## How do you price 'free' electricity?

Wholesale electricity markets usually price electricity according to the cost of producing a marginal unit of power. Once the system is dominated by renewables that are very low cost to run, this may begin to create problems, at least from the perspective of renewable generators. Increasing levels of renewables tend to depress prices through the so-called 'price cannibalisation' effect.[10] This was observed during periods of low demand during the first Coronavirus lockdown in the UK at the start of 2020.[11,12] The effect is even more pronounced for wind plant, as their output tends to be correlated with periods when prices are low, meaning they receive a reduced so-called 'capture price'. The effect will tend to get stronger as more wind enters the system. To a large extent, this effect is structural, it reflects the changing physical nature of the system interacting with wholesale market price formation, rather than the policy framework in place.

The price capture effect can be partially offset by increasing system flexibility through making consumer demand more responsive as well as major infrastructure solutions such as long-term storage and long-distance interconnectors. For example, electrolysis for producing green hydrogen[13] could be a major source of demand to soak up large quantities of power when the wind is blowing, helping to prop-up prices during these periods. Delivery of this infrastructure and capability is quite uncertain.[14] Future demand for green hydrogen depends on decarbonisation pathways for industry, transport and heat. Total demand for power is also dependent on these pathways. This indicates the strong interrelationship between the investment case for renewables and other elements of the energy infrastructure needed for the energy transition. Crucially, many of these infrastructure pathway choices are also dependent on public policy and are outside the control of power market participants.[15]

There are also questions about the sequencing and coordination of the different components of the net zero transition. The availability of surplus electricity at certain points of the day or year ought to provide an incentive to invest in demand response or storage, but demand and supply both respond to low prices. Whilst low or negative power prices ought to stimulate demand, they might just choke off supply. Investment in low carbon generation could slow or simply even stall before the smart chargers, interconnectors or green hydrogen plants turn up. Indeed, a great many risks surround each of the various component parts of a net zero electricity system. In the long-run, a fundamental question facing policymakers is whether a different market structure will be needed that moves away from system marginal cost (which mainly focuses on running costs) to one that reliably remunerates capital costs, which is where the bulk of the cost of renewables and other low-carbon infrastructure lies.

**Increasing levels of renewables tend to depress prices**

## A debate over market design

'Contracts for Difference' (CfDs) are the centrepiece of policy support for renewable energy schemes in the UK. With prices set through auctions, they provide government-backed 15-year contracts to deliver green electricity. They were created in the Energy Act of 2013 to help de-risk low carbon energy projects by insulating them from wholesale power price uncertainty for at least a part of their operational life and providing a reliable counterparty.[16] This has made renewable energy projects attractive to low-risk investors such as pension funds who control large pools of low-cost capital. These arrangements have helped see the prices offered to new offshore wind farms in Great Britain plummet from well over £100/MWh to below £40/MWh (2012 prices) – making offshore wind cheap compared to almost all other forms of power generation.[17] Onshore wind and solar can be even cheaper under these arrangements.

Now that renewables are so cheap, some commentators are questioning whether they need the continued government support, arguing that markets might be able deliver decarbonised power more efficiently without the provision of these long-term contracts.[18] They argue instead for an alternative approach, such as a low carbon obligation on suppliers.[19] The logic is that although CfDs make investment less risky, they also largely remove any incentive for renewable generators to respond to the short-term price signals that reflect the value of electricity in particular locations or at particular times of the day or year. The central rationale behind this argument for reforming or removing CfDs is that if renewable projects were fully exposed to wholesale price movements over time and in different locations, renewable generators could be incentivised to generate more when demand is high and not to generate when demand is low. This is also linked to a wider set of arguments associated with incentives for demand response and provision of flexibility.[19]

**offshore wind is cheap compared to almost all other forms of power generation**

Others argue that applying this approach to wind and solar generators would put the cart before the horse in terms of investment priorities when we have only just started to deliver the massive shift in the country's power infrastructure needed for decarbonisation of the electricity system by 2035, and electrification of other sectors in order to meet net zero.[20] Since renewable power generation will form the bulk of total electricity system costs in the future, the primary policy objective should be to maintain as low a cost of capital as possible during the build-out phase. There are two dimensions to this. The first being to manage change gradually to avoid disruption for in-flight investment.[b] The second is a longer-term question of how to ensure that any new long-term market or policy designs address the problems associated with price cannibalisation and ensure that investment in, and operation of, low carbon generation is not undermined. CfD contracts run for 15 years but the operational life of wind farms extends far beyond that. One rationale for future market reform is to avoid price cannibalisation leading to premature closure of low carbon assets, potentially being displaced by a new wind farm with access to a CfD at greater overall cost.

## Risks, they are a-changin'

Financial risk management is a complex topic, but a simple rule of thumb generally applies – higher risk projects require a higher rate of return to attract investors which, all else equal, increases project costs. This is particularly significant when projects are dominated by upfront capital investments rather than ongoing running costs as is the case for renewables and other low-carbon infrastructure. Exposing project developers to risks they are well placed to manage can help to sharpen the design of projects, reducing the chance that consumers get saddled with the costs of poor project choices. However, exposing projects to risks they are not well placed to manage raises the cost of capital with no commensurate benefit in terms of project quality. It is therefore important to understand the nature of the risks facing renewable power projects as the electricity system transitions towards zero-carbon generation.

[b] The market is now delivering some renewable energy projects outside of current policy support mechanisms. They tend to have higher risk exposure than government-backed CfDs, having higher counterparty risk and shorter contract tenors (which leaves greater tail risk). Currently, these remain a low proportion of the total market (below 1GW out of a total of 48GW). The extent to which they could be scaled to cover the bulk of the wind power needed over the next 10-15 years remains untested.

The importance of keeping capital costs and the costs of raising capital as low as possible are underlined in the Net Zero Strategy, which notes that the principal economic costs of net zero arise because of the capital intensity of low carbon. These are huge, equating to something like 1 – 2% of GDP.[21] Similarly, the CCC assessments of net zero emphasise the importance of capital expenditure in the initial phases of decarbonisation, noting how this eventually provides a payoff in the form of huge reductions in gross expenditures on fuels.

At this stage in the energy transition, uncertainty over the size and fundamental characteristics of the electricity system could present risks which project developers and investors are not in a good position to manage. Arguably, these systemic risks are at their highest point in the near future given the policy dependent pathway choices that lie ahead. As the system progresses through the transition, some of these pathway uncertainties will be resolved.

In the meantime, if the cost of capital dominates the overall cost of delivering the infrastructure investments that underpin the zero-carbon transition, this would suggest that now is not the time to change course on de-risking investment. This is not to argue for maintaining current CfDs in perpetuity. Indeed, a de-risking mechanism only partially covering the operational life, with only partial coverage of the market may lead to avoidable additional costs and a sub-optimal outcome.

However, to inform the debate about the impact of moving away from the CfDs it is important to properly understand the scale of any impacts on investment risk. We need to quantify the impact of the risks imposed by marginal cost price formation on offshore wind and other renewables so that the costs and benefits of new market and incentive designs can be better understood.

# Part 3: Quantifying zero-carbon electricity market risks

At its heart, the complex debate on market design outlined above comes down to a relatively simple equation:

**Do the cost savings arising from low cost of capital achieved through de-risking policies outweigh the potential system cost benefits that might arise from exposing renewables projects to greater levels of market price risk?**

This section sets out the results of analysis that aims to provide evidence on the first part of this equation. The analysis is not setting out to define the market design pathway with the overall lowest cost, but is assessing the impact on financing costs of different market design options from the perspective of new projects. Later analysis will explore and seek to bring together other elements to inform decisions on the next electricity market reform for GB.

## Step 1: How different are future scenarios of zero-carbon electricity?

We start by assessing the degree of uncertainty over which decarbonisation pathway we may be on. This uncertainty relates to physical characteristics of the system such as the type of generation on the system, the shape and scale of demand, and the availability of different types of flexibility options such as interconnectors, hydrogen etc. We have based this analysis on the four National Grid ESO Future Energy Scenarios (FES)[22] for 2040. We also introduce some variants which test exposure to the risk that major flexibility infrastructure (i.e. electrolysis and interconnectors) do not get rolled out to the extent assumed in the main scenario.

Three of the FES scenarios meet net zero goals:

- **Consumer Transformation (CT)**. Based on electrified heating, consumers willing to change behaviour, a high level of energy efficiency and a high degree of demand-side flexibility and interconnection to Europe. Wind power reaches 116 GW by 2040. We also test a lower interconnector variant.[c]
- **System Transformation (ST)**. Based on a greater role of hydrogen for heating, consumers being less inclined to change behaviour, lower energy efficiency and a greater reliance on supply-side flexibility, interconnectors and electrolysis. Wind capacity reaches 97 GW by 2040. We also test a low electrolysis variant.[d]
- **Leading the Way (LW)**. Based on the fastest credible rate of decarbonisation across the economy as a whole, implies significant lifestyle changes, and includes a mix of hydrogen and electrification of heating. Wind capacity reaches 117 GW by 2040. We also test a low electrolysis variant.[e]

The final FES scenario fails to make enough progress to be compatible with net zero goals:

- **Steady Progression (SP)**. Based on the slowest credible rate of decarbonisation, minimal behaviour change, slow decarbonisation rates in power and transport, and heat fails to decarbonise. Wind power reaches 77 GW, and there is more than 40GW of unabated gas power remaining on the grid in 2040. We also test a variant with higher carbon prices.

The role of the FES scenarios in our work is simply to illustrate some of the uncertainties that surround the composition and characteristics of a notional future power system.

[c] This assumes interconnector capacity reaches 19GW compared to 27GW in the main CT scenario.
[d] This assumes electrolysis capacity reaches 5 GW compared to 10 GW in the main ST scenario.
[e] This assumes electrolysis capacity reaches 12 GW compared to 24GW in the main LW scenario

We use them to generate a set of hypothetical system prices so we can explore risks. Other scenarios are available, and the analysis does not seek to demonstrate which scenarios are better, more likely, or plausible.

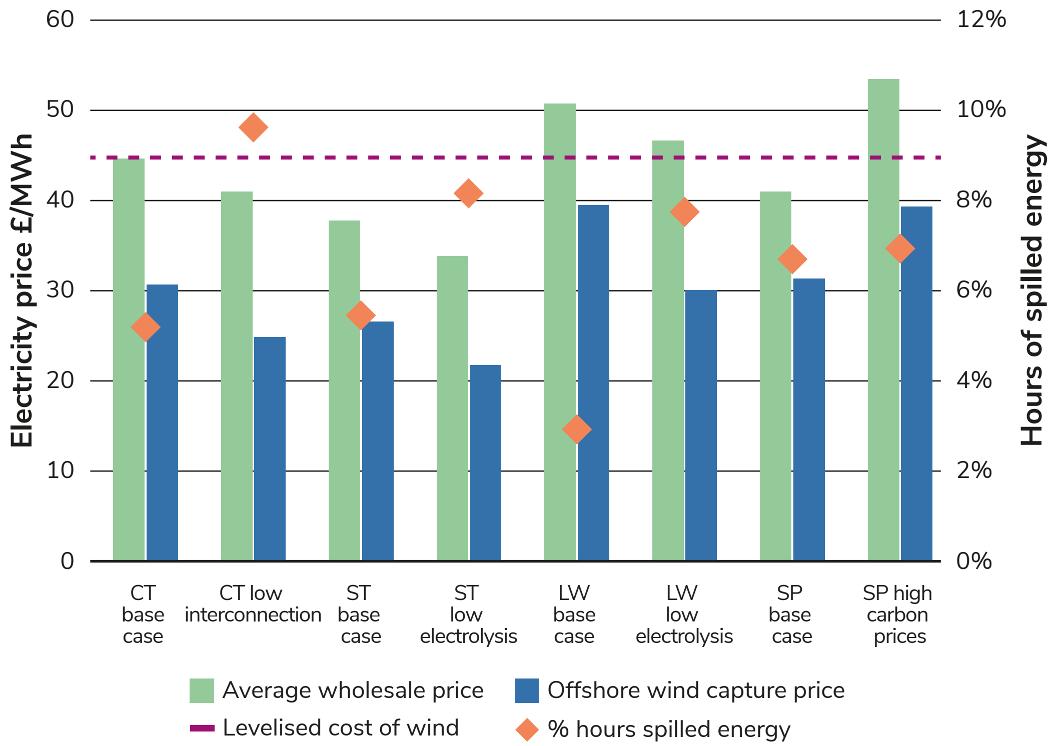
## Step 2: How do physical differences translate into wholesale price risk?

We use the open-source electricity system model Antares[23] to assess how these different electricity system configurations would affect electricity price formation. The model provides a highly simplified view of the GB system as part of the wider European power grid. It provides a means to generate wholesale electricity prices taking into account the following key factors:

- Future shape of demand across Europe[24] (variations by day and by season)
- The effects of interconnection from GB to mainland Europe
- Wind output correlation across Europe based on historical weather data
- Assumptions about future electricity generation in both GB and other parts of Europe

Figure 1 shows that relative to our base case Consumer Transformation scenario, capture prices are lower in the low electrolysis and low interconnector cases, indicating the risk exposure of wind projects to the presence or absence of this kind of flexibility infrastructure. The degree of 'spilled energy' events (i.e. when electricity supply exceeds demand) is also higher in these low flexibility scenarios. This is important as some policy designs are designed to stop remunerating projects in these circumstances.

**Figure 1. Price cannibalisation and periods of excess supply in different decarbonisation pathways**




Please see page 8 for details of each of the CT, ST, LW, SP scenarios

## Step 3: How do different policies affect exposure to these risks?

Figure 1 shows that in all the scenarios tested, the capture price is below the levelised cost of wind, meaning that wholesale prices on their own are insufficient to recoup investment costs. In this step, we look at how these price variations translate into investment risk, taking account of different types of additional revenue sources that might be available either from policy support mechanisms or from the market to bridge the gap between capture price and levelised cost.

The additional revenue sources presented here include a 2-way CfD that fixes prices for the first 15 years of a new-build, a 2-way CfD that fixes prices but does not pay out when prices go negative,[f] and a 1-way CfD that fixes a price floor but allows plant to profit from upside risks. We also present two simplified representations of the additional market revenues that could be envisaged to procure long-term power from renewable sources. These are represented as an additional premium paid on top of the wholesale price, the first case being a fixed premium, the second case being a variable premium where the variability is correlated with the electricity price (more details in the Appendix).

We don't attempt to define how such premium mechanisms could emerge and/or whether they would be delivered through market participants or policies.

They are broadly consistent with what would be needed under a 'low carbon obligation' approach to policy[18] but such an approach is neither a necessary nor sufficient condition for the existence of such a premium. Whether or how such premium payments could or would occur is not the purpose of this analysis.[g] These options are included so we can represent the risk implications of exposing investors to a price environment based on system marginal price.

In all cases the policies we present are simplified and illustrative, a range of variants can be envisaged, and alternative policies could deliver a similar outcome. For example, a 1-way CfD might be expected to have similar characteristics to a market-wide floor price, the fixed premium might or might not be a feed in tariff, the negative price rule could be applied selectively and the analysis does not take account of opportunities to value stack, for example in providing ancillary services.

Using the Consumer Transformation (CT) scenario as a base case, we then assess how the other scenarios would affect projects' returns and express this difference as a discount rate impact.[h]

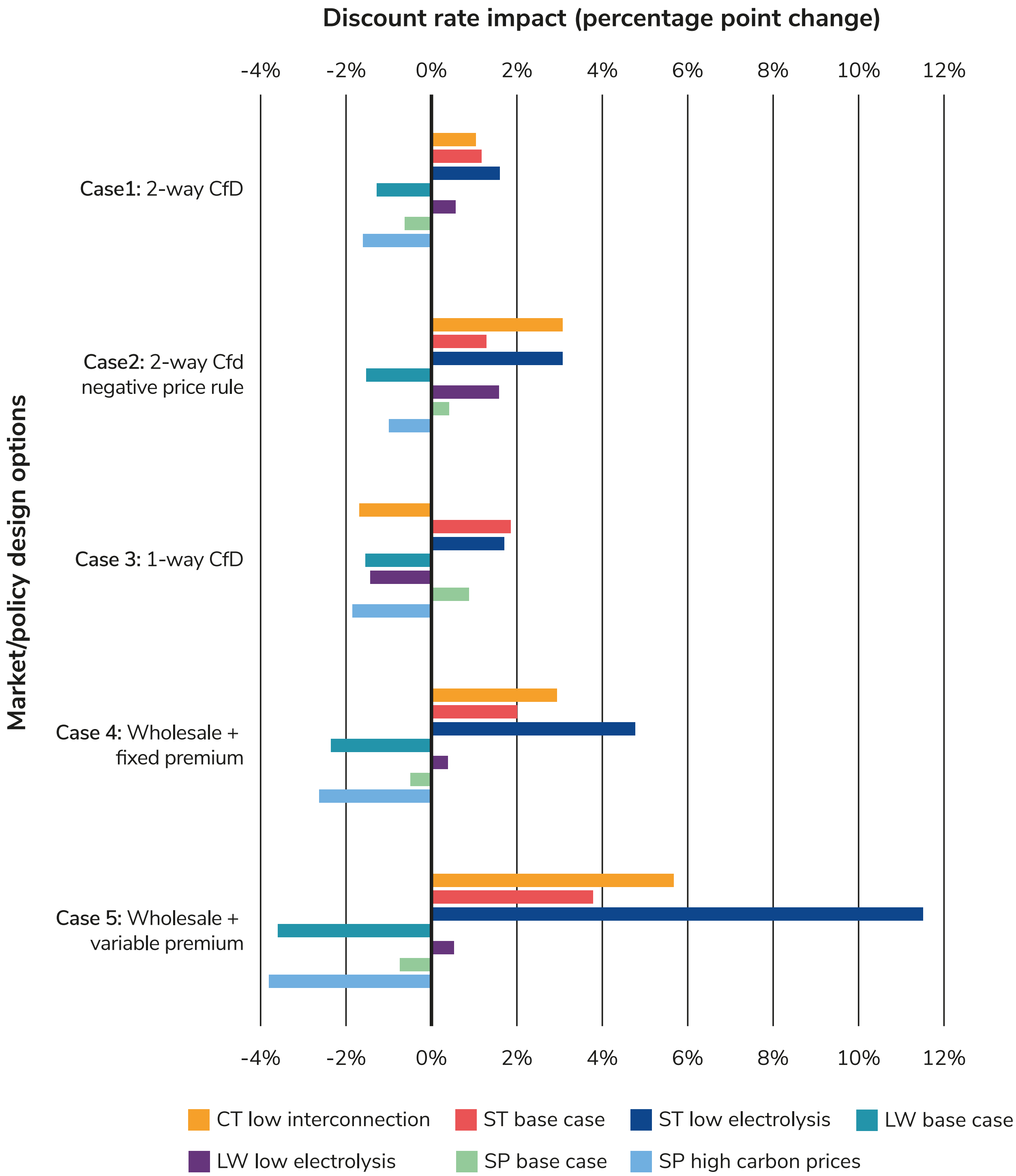
Figure 2 shows for offshore wind projects how the different policy regimes (listed down the vertical axis) result in different levels of exposure to the risks of different decarbonisation pathways (indicated by the different coloured bars).

[f] A fifteen year 2 way CfD with a negative price rule is broadly similar to current arrangements. However we do not place a time limit on payment during periods of negative supply.

[g] If they did not emerge, or investors feared that they would not, this would amount to 'missing money' that would result in underinvestment and failure to deliver against climate targets.

[h] The discount rate impact is calculated as the change in the discount rate required to get back to the same net present value expected in the base case. The downside risks help give an indication of the extent to which investors will need to be compensated for this risk in their returns. However, the cost of capital impact will be lower than the discount rate impact because different types of investor will value risk differently and some will also take into account the upside risk.

**Figure 2. Risk exposure of offshore wind projects to different decarbonisation pathways under different policy and market regimes.**




Please see page 8 for details of each of the CT, ST, LW, SP scenarios

The righthand side of Figure 2 indicates how **downside risks** increase relative to the CT reference scenario as we go down this tornado chart. These downside risks are the key driver for assessing cost of capital. The key messages here are:

- The **2-way CfD** and **1-way CfD** cases provide the highest degree of de-risking of the options assessed, with downside risks limited to around 1%.
- The **CfD with negative price rule** exposes projects to higher levels of downside risk (up to 3%) driven by uncertainty over the extent of periods of oversupply.
- The two **wholesale market scenarios** also show considerable exposure to downside risk (2 6% or more), particularly relating to risk of lack of investment in major flexibility infrastructure (electrolysis and interconnectors).

This 2-6% range excludes the ST low electrolysis case. Whilst this scenario does not seem outlandish physically, more work is needed to assess whether downside risks of almost 12% represent an outlier result. We include the scenario in the chart, but to be cautious have excluded it from the cost of capital impact assessment in the next section.

The **upside risks** also have important policy implications:

- The **1-way CfD** allows projects more upside benefit from decarbonisation pathways that result in higher capture prices than in the reference scenario. However, these upside benefits may incentivise choices that reduce wider system costs.
- The **Steady Progression** pathway, which fails to decarbonise, presents an upside risk to wind investors (i.e. delivers higher capture prices than in the reference scenario), particularly for policy cases 3-5 where projects are more exposed to market price risk.[i] The effect is more pronounced with a higher carbon price variant. This is a concern as it could lead to a disincentive to fully decarbonise unless strong additional policy measures are in place.

## Step 4: Implications for the cost of delivering offshore wind?

The final step is to illustrate the impact of these risk premiums on the implied cost of delivering the total stock of offshore wind expected in our base case scenario. The risk premium for a project is just one of many factors that will impact cost of capital. In practice financing costs will be affected by a range of project specific factors, including the debt leverage that can be achieved by different investors, and financial markets' risk appetite. In this analysis, we have not attempted to address these more complex aspects of project financing, but make the observation that although cost of capital will vary for different investor types, the calculated discount rate impacts are illustrative of the scale of impact of different policy options on cost of capital across the market.

From Figure 2, we observe that the (downside) discount rate impacts of the most market-exposed options (Cases 4 and 5) are mostly between 1-5 percentage points above the least market-exposed option (Case 1). We use this range to illustrate the potential impact on cost of delivering the offshore wind envisaged in the Consumer Transformation scenario. This amounts to 80 GW installed capacity, generating 350 TWh of electricity by 2040. This calculation indicates that every percentage point increase in the cost of capital implies an additional £1 bn to the cost of delivering the full fleet of offshore wind expected to be needed.

[i] A related issue affects price setting by interconnectors with Europe. Under the assumptions modelled here, Europe has still not fully decarbonised, so prices received through interconnection are elevated by the presence of a carbon price. This is why 'Lead the Way' scenario, which is highly interconnected to Europe, also looks attractive in these results. Different assumptions about decarbonisation rates in Europe would change this result.

**Table 1. Illustration of the impact of cost of capital on the costs of delivering 80GW offshore wind by 2040**

| Cost of capital | | Base | +1% | +2% | +3% | +4% | +5% |
|---|---|---|---|---|---|---|---|
| **Levelised cost** | **£/MWh** | 43.9 | 46.4 | 49.0 | 51.7 | 54.6 | 57.6 |
| **Annual generation** | **TWh** | 350 | 350 | 350 | 350 | 350 | 350 |
| **Total annual cost** | **£bn** | 15 | 16 | 17 | 18 | 19 | 20 |
| **Increment rel. to Base** | **£bn** | - | 1 | 2 | 3 | 4 | 5 |

# Part 4: Conclusions and implications for policy

**Policy framework choice could impact offshore wind delivery costs by up to a third**

It is clear that all sectors of the economy will have to change rapidly over the next 10-15 years. The broad features of the infrastructure needed for a future net-zero world can already be outlined. These include more renewables, more electrification of transport and heat, demand response, more hydrogen, more interconnectors. There is an urgent policy imperative to ensure that this infrastructure is rolled out fast enough to meet decarbonisation goals.

However, the details of the pathway to net zero are still uncertain. Some of the risks are commercial in nature, but some relate to matters of public policy that lie outside the control of electricity sector players.[j] This distinction matters because imposing risks on investors which they are not in a good position to manage could simply increase the cost of capital needed to finance the transition without any commensurate benefits in terms of improving the design and quality of the projects.

This work attempts to quantify the impact that pathway uncertainty could have on the cost of building out offshore wind.[k] We use published scenarios from National Grid ESO to illustrate these possible different pathways to a zero-carbon electricity system, all of which include very large increases in wind power capacity from 10 GW now to 100-120 GW in 2040. The cost of this amount of offshore wind would be around £15bn per year if financed at moderate cost of capital. Very roughly, for every 1%-point increase in the cost of capital, this figure increases by £1bn per year.

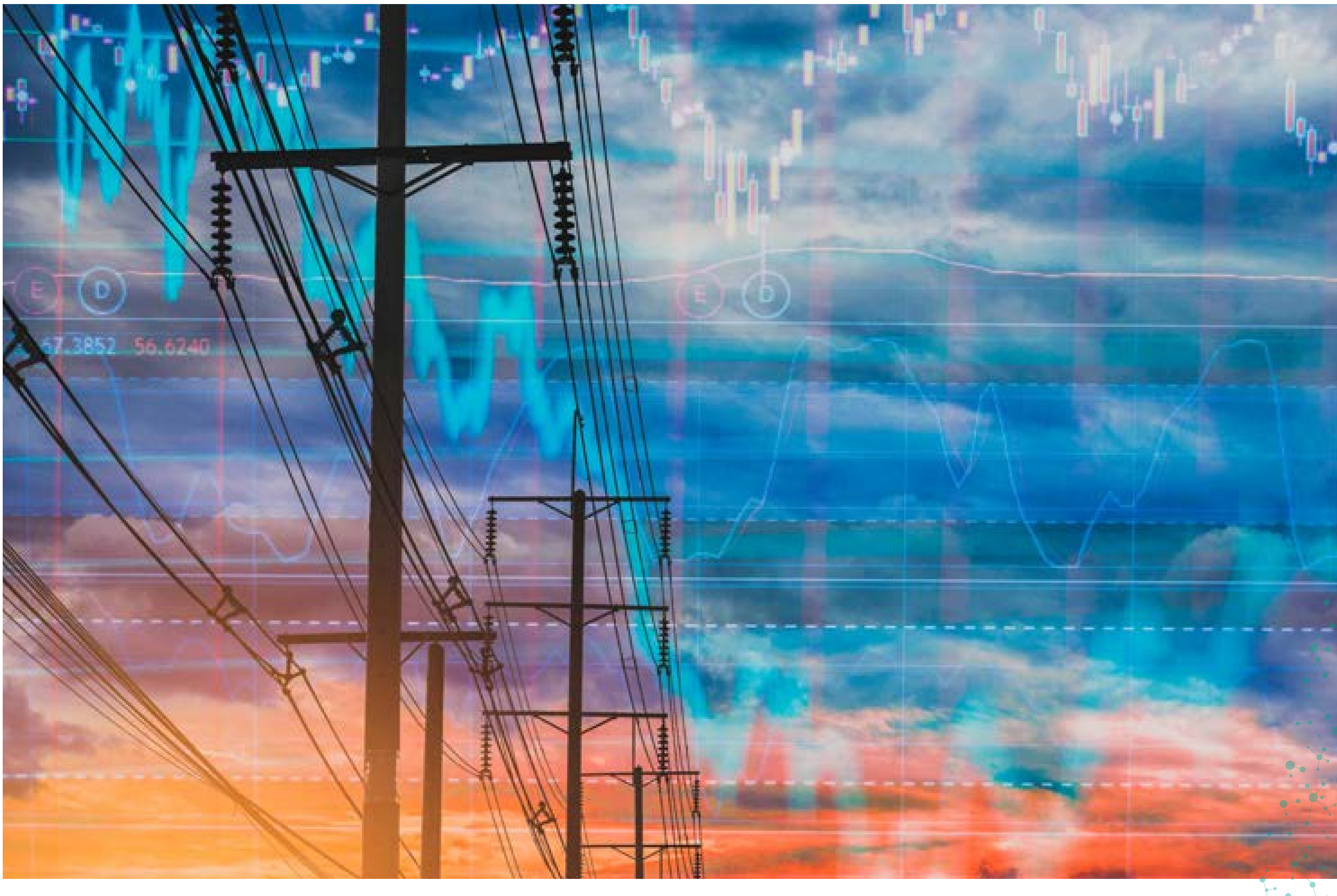
We then look at how exposure to decarbonisation pathway risks varies depending on the policy/market design frameworks in place for remunerating wind power. Initial results indicate that the degree of exposure varies by around 1-5 percentage-points between the most risk-exposed framework to the least risk-exposed. This suggests that the choice of policy framework could impact the cost of delivering the offshore wind component of the low-carbon transition by between £1-5bn per year (up to a third of the overall annual cost).

[j] As examples, we look at the risk of under-delivery of hydrogen and interconnectors, but we have not carried out an exhaustive analysis of different types of risk factor. Further work in this area will be undertaken.

[k] This is an illustration of the wider infrastructure financing challenge. Future work will look at other types of investment.

We have not yet attempted to quantify the degree to which exposing wind projects to more market price risk would achieve cost savings in the wider electricity system (i.e. the grid and balancing costs) by encouraging more efficient choices in the type, design or operation of wind projects. However, to result in a net cost saving, reduction in grid and balancing costs that can be directly attributed to exposing renewables schemes to greater price risk would have to be at least as large as the cost of capital effects. The value of flexibility in a low carbon system is underscored in our analysis and already widely appreciated.[25] However, there are many ways this could be delivered that are independent of CfD reforms; from changes to the Capacity, Balancing and Wholesale markets to new incentives for storage, interconnectors, or demand response. We will return to these topics in future analysis.

This is a relatively simple and stylised analysis designed to illustrate the key 'moving parts' and drivers of risk in the transition. Our intention is to help inform the current debate about what types of policy instrument are the most appropriate to ensure that this investment is delivered in a cost-effective way.[26] Our contribution has been to provide a tool[i] and methodology that helps to quantify financial exposure to different pathway risks which should help assess which risks should be managed by whom.




[i] Based on open-source tools and publicly available data

# Appendix. Policy and market options tested

**Table A1 – Market and policy design options tested (CfD = contracts for difference).**

| | Market / policy design option | Characteristics assumed in cashflow model | Comments |
|---|---|---|---|
| **1** | 2-way CfD | Multi-year contract pays the difference between an agreed strike price (set at auction) and the wholesale market price. In this analysis we assumed 15-year contracts. | By fixing prices for a number of years, it reduces exposure more than the other policy options considered. This is based on the original form of the CfD which led to reductions in auction prices. |
| **2** | 2-way CfD with negative price rule | As above, but does not pay out if prices go negative (we use spilled energy as our indicator of when this would occur) | This exposes projects to uncertainty over the degree of negative pricing events under different risk scenarios. All else equal, would expect projects to bid up auction prices compared to Option 1 to compensate for reduced revenues. This is the current design of the CfD. |
| **3** | 1-way CfD (price floor) | Multi-year contract, fixes a minimum price (including during periods of spilled energy), but does not fix maximum price. | This reduces exposure to downside risk by fixing a minimum floor price at auction, but projects can benefit from any upside if market prices rise above this level, so would be expected to bid lower in the auctions compared to Option 1. Exposure to upside might attract a different type of investor. |
| **4** | Wholesale price + fixed premium | Wholesale price plus top-up set at fixed price per MWh produced | This scenario aims to represent a market-based solution, where electricity users would pay a premium on top of the short-run system marginal cost to procure electricity from renewables, enabling them to recover capital costs. In this case, we assume that there is no volatility in the price of this additional market revenue source, so that it acts like a fixed premium. |
| **5** | Wholesale price + variable premium | Wholesale price plus top-up set at variable price per MWh, variability assumed to be correlated with wholesale prices | As above, but this time we assume there is volatility in the additional market revenue source, with the volatility correlated with the underlying marginal electricity price. |

# References


[1] The Ten Point Plan for a Green Industrial Revolution. HM Government 2020. Access here

[2] The Net Zero Strategy: Build Back Greener. HM Government 2021. Access here

[3] National Grid Future Energy Scenarios. Access here

[4] The Net Zero Strategy: Build Back Greener. HM Government 2021. Access here

[5] Energy Act Electricity Market Reform provisions. HM Government 2013. Access here

[6] Energy Futures Lab 2019, Electricity Markets, Incentives and Zero Subsidy Renewables. Access here

[7] See e.g. RAB Model for Nuclear. HM Government 2019. Access here. And The Carbon Capture and Storage Infrastructure Fund. Access here

[8] Energy White Paper: Powering our net zero future. Access here

[9] Independent-Assessment-of-the-UK-Net-Zero-Strategy-CCC. Access here

[10] Gareth Millar, Cornwall Insight 2018, Wholesale Power Price Cannibalisation. Access here

[11] Bell and Hawker 2020. Electricity demand during week one of COVID-19 lockdown. Access here

[12] UK's power system emissions hit all-time low and wholesale power prices go negative. Access here

[13] Hydrogen in a low carbon economy. Climate Change Committee 2018. Access here

[14] Brexit implications for UK decarbonisation objectives. UKERC 2021. Access here

[15] Rosenow et al. 2020. The pathway to net zero heating in the UK. UKERC. Access here

[16] Department of Energy and Climate Change, 2013. Energy Act. Access here

[17] Jansen et al. 2020. Offshore wind competitiveness in mature markets without subsidy. Nature Energy. Access here

[18] 18. Energy Systems Catapult. 2021. Rethinking Electricity Markets – The case for EMR 2.0. Access here

[19] Day. 2021. Can we make electricity markets work better – or is ambitious reform all just too risky to contemplate? Access here

[20] Bell et al. 2021. BEIS call for evidence: Enabling a high renewable, net zero electricity system. UKERC. Access here

[21] HM Government. 2021. Net Zero Strategy. Access here

[22] National Grid Future Energy Scenarios. Access here

[23] Antares Simulator. Access here

[24] Based on 10-year network development plans for ENTSO-E. Access here

[25] Heptonstall, Phil,Gross, Robert 2021, A systematic review of the costs and impacts of integrating variable renewables into power grids 4 Nature Energy DO- 10.1038/s41560-020-00695

[26] Project TransmiT (2011). Access here

**UK Energy Research Centre,**
**Email:** UKERC@ucl.ac.uk
**Website:** www.ukerc.ac.uk
: @UKERCHQ
: www.linkedin.com/company/
uk-energy-research-centre