Department for Business, Energy & Industrial Strategy

Review of Electricity Market Arrangements Consultation

UK Energy Research Centre response

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October 2022

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UKERC is funded by the UK Research and Innovation Energy Programme.

Questions

Chapter 1. Context, vision, and objectives for electricity market design

1. Do you agree with the vision for the electricity system we have presented?

☒ No

We greatly welcome the detailed and carefully balanced discussion of complex topics, often beset with trade-offs, throughout the consultation document. There is a great deal in the vision that we agree with. We have selected ‘no’ because there are important caveats. We fully agree that if the Net Zero target is to be met the GB power system has to be decarbonised and sectors currently served by direct combustion of fossil fuels need to move in large part to electricity. It is essential to provide the flexibility needed to incorporate large volumes of variable renewables, such as wind and solar, which most assessments find to be cost-effective options to deliver secure and carbon free electricity. This also creates operability challenges and requires significant changes to networks.

We also agree that demand response in a variety of forms can lower overall system costs. Some of this demand response could come from domestic consumers. However, it is important to be clear that there are constraints on the ability and willingness of consumers of all forms to adjust consumption to respond to the availability of energy. Research evidence suggests that participation in demand response is subject to constraints and ought not be overstated (Parrish et al., 2020; Parrish et al., 2019) It is also important to note that the role for demand response from households will be limited until the amount of potentially flexible load is expanded through increased use of EVs and electric heating. This is evidenced in earlier work for BEIS (Chase et al. 2017).

We also caution against the idea that market reform is needed to deliver a ‘step change’ in the deployment of low carbon energy. Indeed, it could be argued that the government already has all the instruments it needs to deliver low carbon generation in increasing amounts, given the success of the CfD scheme and provided that new measures to assist with the development of new nuclear, CCS and hydrogen are successful (out of REMA scope). It would be more accurate to characterise the principal requirement as enhancing flexibility and ensuring resilience and operability without compromising the delivery of low carbon generation.

It is also important to be clear where the main constraints on realising the vision lie. For example, delivering an acceleration in the deployment of offshore wind requires new network capacity, effective processes for managing the conflicting needs for marine ecosystem services, supply chain expansion and so on. It also requires the mobilisation of very large amounts of finance, and it is possible to enhance the contribution offshore wind makes to system operability. The challenge for REMA is to combine ongoing investment support at minimum cost of capital with delivering an enhanced contribution to operability.

We question slightly the assertion that the system will move from centralised to decentralised, given the UK's geography, resource base and policy aspirations for new offshore wind, CCS, hydrogen and new nuclear. Large-scale generation will continue to play a substantial and probably dominant role in providing power, through offshore wind, a continued role for nuclear, and CCS power plants. Economies of scale in onshore wind and solar farms should also be noted. It is also highly likely that the GB system will need more large scale storage, possibly very large scale, interseasonal storage, and it will benefit from increased interconnection. CCS schemes need to be centralised and clustered. Hydrogen could be produced and stored in bulk. All of these are large scale technologies. This does not mean that smaller generators, storage and smart demand options aren't valuable and important. However, a characterisation that describes a transition *away* from large scale to small scale distributed options is inaccurate. There is a risk that local solutions are given overemphasis, particularly if trade-offs arise (for example between national control/coordination and local markets). It would be more accurate to characterise the transition as one from *large-scale, largely flexible fossil-fuel generation, to a mix of small and large scale generation that is inflexible and/or variable, with an opportunity to expand the role of active demand-side participation and new sources of flexibility at a range of scales.*

Our final cautionary note is on the relationships between retail and wholesale markets. We understand why the retail market is out of scope for this consultation. However, several of the options considered below are only feasible if suppliers are relatively large, sophisticated, well capitalised and above all solvent. The health and structure of the retail sector will also affect the ability of suppliers to engage with consumers and implement smart solutions. Treating the two parts of the market in parallel risks overlooking some of the key interdependencies.

References:

Chase A, Gross R, Heptonstall PJ, Jansen M, Kenefick M, Parrish B, Robson P et al., 2017, Realising the Potential of Demand Side Response - A report commissioned by BEIS

Parrish B, Heptonstall P, Gross R, Sovacool BK et al., 2020, A systematic review of motivations, enablers and barriers for consumer engagement with residential demand response, *Energy Policy*, Vol: 138, Pages: 1-11, ISSN: 0301-4215

Parrish B, Gross R, Heptonstall P, 2019, On demand: Can demand response live up to expectations in managing electricity systems?, *Energy Research and Social Science*, Vol: 51, Pages: 107-118, ISSN: 2214-6296.

2. Do you agree with our objectives for electricity market reform (decarbonisation, security of supply, and cost-effectiveness)?

☒ Yes

We fully agree with the top-level objectives of decarbonisation, security and affordability. However, some of the argumentation around each aspect is somewhat surprising.

We question the contention that price signals are key to enabling consumers to engage with the decarbonisation agenda. If demand-side participation is to be realised then we need to ensure that electrification of heat and road-transport proceeds apace. Policies to drive this are obviously outside the remit of REMA but are highly relevant since charging infrastructure will affect smart charge capability, and heat pump/home insulation levels will affect any potential for smart heat pump operation. Our research suggests that trust, simplicity and automation are principal motivators for consumers to participate in demand response programmes or tariffs. Whilst it is correct to observe that some consumers need to be exposed to time-of-use prices this is not likely to be a major driver for the roll-out of EVs or heat pumps. And if they are to participate in system operation it is more likely that suppliers or intermediaries exposed to real-time prices and offering automated solutions will enable consumer participation. This is particularly the case for dynamic demand response, rather than fixed time of day tariffs, as our research shows this is difficult for consumers to engage with and dynamic time of day tariffs are largely unproven (Parrish et al., 2020).

It also seems strange to place consumer engagement with price signals under the decarbonisation objective rather than affordability objective. Power sector decarbonisation can be delivered without demand side engagement, it just may be more expensive. Similarly, it is surprising that the opportunity to reduce exposure to volatile global fuel *prices* is associated with security of supply rather than affordability. In the current context, interruption of Russian gas supply into Europe is the main threat to supply security, but this isn't in the remit of REMA as we understand it. If gas prices remain at elevated levels it is likely to be substantially cheaper to provide energy using renewables and nuclear. This does not obviate the importance of flexibility and cost effectiveness, but it does underscore the primacy of mobilising investment in non-fossil technologies. The build out of non-fossil generation serves to improve affordability, decarbonisation *and* security of supply.

References:

Parrish B, Heptonstall P, Gross R. 2020/ A systematic review of motivations, enablers and barriers for consumer engagement with residential demand response. Energy Policy, Vol: 138, Pages: 1-11, ISSN: 0301-4215. Available at: https://www.sciencedirect.com/science/article/pii/S0301421519308031

Chapter 2. The case for change

3. Do you agree with the future challenges for the electricity system we have identified? Are there further challenges we should consider? Please provide evidence for additional challenges.

☒ No

We agree that there are challenges associated with investment, flexibility, location/network constraints, system operation and price volatility. We welcome the careful and detailed exposition of issues and the provision of carefully balanced discussion of potential competing factors such as de-risking of investment vs short term price signals. However, we believe that the challenges associated with location/network constraints and price volatility are misconstrued, particularly in the summary form provided in the opening bullets of the case for change. This risks policy focus and prioritisation being wrong, to the detriment of the objectives REMA is seeking to achieve. This is particularly concerning in the case of location/network constraints.

The locational problem is described in terms of resource base and planning constraints leading to wind and solar deployment at the 'extremities' of the network. This is partly correct, since it is not possible to locate offshore wind farms on land, and onshore wind developments need to locate in locations with suitable sites and desirable wind characteristics if the UK's large wind potential is to be exploited and the cost of generation is to be minimised. Wind speeds in the top 10% of wind sites in Scotland are about 40% higher than those in England, and windy locations in England, Scotland and Wales typically offer twice the power density of the South East of England (see Global Wind Atlas). In very broad terms this tends to push onshore wind developments to the North and West of Great Britain, although offshore wind farms are also widely distributed along the East and South coasts of England.

The problem is characterised as one of locational pricing being inadequate to counteract this tendency for renewable generation to locate in the 'wrong place'. It would be far more accurate to characterise the problem as being that the current electricity transmission and distribution networks are in the wrong place. This is because they were constructed in a different century, to exploit a fossil fuel resource base (domestic coal) that the UK has largely moved away from. Britain had the first integrated power grid in the world, the original 132kV national grid started operation in 1935. The 400kV grid was designed and built from 1965 with the express purpose of moving energy from areas where it was economically efficient to locate large coal or nuclear power stations to demand centres. In short, our power grid was built in the last century in a completely different context and it is *that* which is the fundamental problem.

Our concern is that the way the challenge is conceived places the cart before the horse. It treats the transmission system as if it were the fixed point around which locational signals should encourage demand, storage and generation to revolve. Taken to an extreme the outcomes could be either to miss the objective to decarbonise or to add substantially to the cost of doing so by pushing renewables into unproductive low wind areas. Locational pricing has a role, but it is important to be very clear that the problem is not that accessible renewable resources, or demand centres, are in the wrong place, or that planning arrangements push renewable deployment offshore. The problem is that the electricity network was built in a previous age. As a result, we lack network capacity where we need it for the future - a problem that government policy can and must fix. This will take time, but sharp and/or risk/uncertainty inducing locational pricing should be temporary unless there are unresolvable or unduly expensive restrictions on upgrading parts of the network. Simply put, in characterising the challenge as one of network pricing rather than network capacity, REMA risks focusing on the wrong solution. See Q11.

The consultation characterises electricity price volatility as a problem that needs policy to 'mitigate.' However, price fluctuations have the potential to be useful, both as investment and operational signals, as the system changes to accommodate variable renewables. For example, low or negative prices on windy days, and high prices on low wind days, are useful signals to investors in storage or demand response. Whether, and to what extent it is useful to expose wind, solar or nuclear operators to these price signals is a separate conversation that we deal with in our discussion of decarbonisation incentives. However, it would be a misconception to characterise such price signals as inherently problematic.

The impact of fossil fuel price fluctuations on wholesale power prices (usually over a months to years timeframe, overlaying time of day price signals, and currently dwarfing them) is another matter. Reducing exposure to very high fossil fuel prices caused by political or global economic events is in almost every respect likely to be socially beneficial. Rather than seeking to mitigate price volatility per se it would be more accurate to characterise the challenge as seeking to reduce exposure to fossil fuel price variability. Doing so would reduce exposure to economically disruptive, extreme high fossil fuel price events outside the control of the UK.

We therefore suggest that it would be helpful to separate out two distinct challenges and avoid conflation between them. The first is to reduce exposure to and disruption from volatile global fuel prices. The second, distinct, challenge is ensuring that wholesale electricity price variations related to demand and supply of electricity send beneficial signals to investors in flexibility but do not undermine the investment case for low carbon generation.

4. Do you agree with our assessment of current market arrangements/that current market arrangements are not fit for purpose for delivering our 2035 objectives?

☒ No

We agree with many of the issues identified, but the list of 'issues' raised in the decarbonisation section doesn't include the need to cost-effectively finance and deliver 10s of GW of wind and solar plants, together with new nuclear, CCS or hydrogen generation. This may be because the current system (CfDs) is assumed to deal with this (i.e. that's not the bit that is broken and needs to be fixed). The problem with this framing is that it tends to focus on all that is wrong with the current system, without taking into account the value of the things the current arrangements are currently delivering well. 'Fit for purpose' depends very much on the relative weighting of these factors. In our answers to Qs 29 to 31 we provide evidence of the impact on the cost of capital of moving away from CfDs. The outcome of this analysis is that very significant benefits in terms of enhancing flexibility would need to be delivered by doing so.

It is important to note that this does not mean that there is no case for change. But it is important not to conflate the case for changing some of the existing arrangements, such as the capacity mechanism, and making incremental improvements to others, such as the CfD, with the need for wholesale changes to *the entirety* of the current set up. In addition, change in and of itself has the potential to disrupt investment, so the REMA process itself has a bearing on delivering 2035 objectives, indeed it has the potential to undermine them. The need to retain investor confidence is acknowledged in the consultation document, but it is not perhaps best served by the rather stark conclusion that current arrangements *per se* are not fit for purpose.

Chapter 3: Our Approach

5. Are least cost, deliverability, investor confidence, whole-system flexibility and adaptability the right criteria against which to assess options?

☒ Yes

The criteria are very sensible. It would be helpful to develop a hierarchy of criteria, for example if changes to improve locational, flexibility or operability could undermine investment or increase the cost of capital how is this trade off to be managed? It would also be useful to develop a temporal dimension to the hierarchy of criteria or means to manage trade-offs. For example, it is likely to be beneficial to prioritise the de-risking of investment in low carbon generation and to provide investor friendly incentives for investment in flexibility for a period of several years hence. During this period investment in new network capacity will also be a high priority. Once the asset base of the system has changed significantly it may then be more important to shift focus onto operational efficiency. This shift of focus could take place gradually, so that successive rounds of investment are exposed to increasing degrees of exposure to incentives focused more on operability or response to system needs/short term price signals. Existing investment would need to be grandfathered and it is important to avoid undesirable levels of lock-in to inflexible operation. However, we believe that explicit recognition that the hierarchy of criteria will change over time offers an additional guiding principle for market design choices and sequencing.

This approach is consistent with what the consultation document describes as ‘the case for evolution’ in the section on cross-cutting issues. However, we suggest that ‘evolution’ is not quite the right word, since evolutionary processes are inherently unplanned. It would be more accurate to describe this as a planned transition. The energy system needs to go through a transition to deliver net zero. As the system changes incentives also need to change. Experience suggests that ‘once and for all’ reforms to energy markets are in fact time limited. Rather than attempting to define a fully optimised set of arrangements ex ante it might be more pragmatic to acknowledge that policy learning is beneficial, contexts shift and unintended consequences are inevitable. This is why markets were nationalised then privatised, the pool gave way to NETA then BETTA, the Renewables Obligation was banded then scrapped, EMR happened and so on. It is hugely unlikely that REMA will discover the final cut on energy policy. UKERC would be interested in helping the REMA team work through the advantages and disadvantages of a gradualist approach to electricity market design changes. This could learn from research evidence on energy transitions of the past and in other countries (for example see Gross and Hanna 2020).

References:

Gross R, Hanna R, 2019, Path dependency in provision of domestic heating, *Nature Energy*, Vol: 4, Pages: 358-364, ISSN: 2058-7546

6. Do you agree with our organisation of the options for reform?

☒ Yes

Very good!

7. What should we consider when constructing and assessing packages of options?

It is important to note interactions between options and the potential for trade-offs. In particular, we note that some options to improve operability, reduce network constraints or enhance flexibility could undermine investment in bulk low carbon power. Some options are contingent on action that is outside the scope of REMA. Developments in the retail market will affect the possible role that suppliers might play. Progress with network upgrading and expansion will affect the need for and scale of locational pricing.

Even within the energy-only market domain there is a large plurality of market arrangements internationally – as we illustrate below in Table 1, developed by Prof. Green at Imperial College Business school. This suggests that there is no such thing as an idealised market. Rather there is a menu of choices for market design, each of which will bring a variety of pros and cons. The implication is that a combination of market design options needs to be internally consistent, associated with good governance, and fit for purpose.

Table 1: The Range of Choices (Richard Green, ICL-Business School)

		Great Britain	Ireland	Denmark	Germany	Italy	Spain	South Australia	California	New York	Texas (ERCOT)
Bulk Energy Trading	Bilateral	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Auction with PAB										
	Auction with pay-as-clear	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Bidding	Free	✓[a]	✓[a]	✓[a]	✓[a]	✓[a]	✓[a]	✓	✓	✓	✓
	Cost-based		?						M	M	M
Dispatch	Self-dispatch	✓		✓	✓		✓				
	Central dispatch		✓			✓		✓	✓	✓	✓
Reserve, etc.	Separated	✓	✓	✓	✓	✓	✓				
	Integrated							✓	✓	✓	✓
Spatial differentiation	Market-wide	✓	✓								
	Zonal			S	N	S	N	S			
	Nodal								✓	✓	✓

N: nation-wide in multinational market S: sub-national zones in operation

Chapter 4: Cross-cutting questions

8. Have we identified the key cross-cutting questions and issues which would arise when considering options for electricity market reform?

☒ Yes

We answer questions 8 and 9 together.

9. Do you agree with our assessment of the trade-offs between the different approaches to resolving these cross-cutting questions and issues?

☒ No

A number of topics are discussed in Chapter 4. We agree that these are important issues. Broadly speaking many of the key trade-offs are included.

However, we are concerned that some of the sections do not treat the perceived trade-offs in an even-handed manner and fail to acknowledge the extent to which the significance of or means to deal with a trade-off is already well established. The section entitled ‘role of the market’ fails to capture the fact that in the electricity sector there are multiple markets in operation simultaneously, and that 'non-market' factors profoundly influence the way the 'market' functions. The section purports to discuss the 'role of markets' per se, but is actually focused on the role of the *energy-only* wholesale electricity market (with an implied focus on day ahead market prices that neglects hedges and long-term contracts). This market is complemented by those for ancillary services and balancing (and could not maintain secure supplies without them), it is significantly impacted by the market for gas and carbon price, and profoundly affected by network investment decisions. We assume that the discussion is predicated on the conception that CfDs and capacity markets are 'non-market' interventions. This is a very purist conceptualisation. Central contracts with prices set by auction are also a form of market. If technology-neutral and outcome based they also provide many of the benefits associated with energy-only markets in terms of price discovery and efficiency. They simply procure over a different time horizon and through a centralised bidding process.

The relatively narrow conceptualisation of markets goes further, since in referring to self-organising arrangements between generators, suppliers and consumers the implication is that the market is arranged on the basis of self-dispatch and bilateral trading. This precludes centralised despatch, which in turn would appear to rule-out LMP. The discussion acknowledges that there are limits to what this particular vision of an energy only market can deliver. This is correct, but not because of market failures. Instead, this is because the wholesale energy market is only one component of a system of interacting institutions and arrangements that combine to deliver electricity securely, affordably and with declined carbon emissions.

We also question the role that consumers are described as playing in this idealised market world. The research evidence does not support the idea that consumers would 'choose time of day tariffs or certain other time of day'. *Some* consumers would, but the evidence is clear that the majority of consumers choose *not* to opt-in to time of use tariffs or demand response programmes. Indeed, achieving buy-in to time of day or smart tariffs is a challenge in itself (Chase et al., 2017; Parrish et al., 2020).

If REMA is to define a system of practical, real-world arrangements that will transform the energy system then it is important to avoid the implication that there is an idealised, first-best, (energy only) market world, against which a second-best world of intervention can be judged. This risks constantly seeking solutions which are already known to be impractical or unworkable and a constant desire to further reform or rework pragmatic arrangements that are already delivering societal objectives on the basis that they are not sufficiently 'market-based'. Markets have many strengths, but they take a variety of forms and they have their limitations - that go far beyond the classic concept of market failure due to externalities. These include where they are not likely to deliver optimal outcomes (e.g. where there are coordination requirements and natural monopolies), where they are absent, or where particular forms of market participation is limited and/or unwelcome.

As we note in the answer to Q7 there is a plurality of options even for energy-only markets. Moving beyond the energy-only domain context becomes key. Countries with little concern about capacity adequacy would be unlikely to implement mechanisms, for example.

We also note the discussion of trade-offs between de-risking investment and exposure to locational or operational price signals. We agree that there is a trade-off here. We fully support incremental changes to the CfD that encourage greater flexibility and/or provision of ancillary services. However the trade-off is not straightforward. This is again because network capacity upgrades are exogenous to the discussion but profoundly affect the significance of locational price signals on the investment timeframe. In addition, as we explain in the answer to Q31 there may be nonlinearities associated with price exposure. In addition, it is not obvious that exposing generators who are unable to respond is more cost effective than creating incentives for other market participants. The example of co-located storage is an excellent case in point. If the problem is constraint management then this may or may not help (see below). If the purpose is simply to arbitrage across time periods then why would an entirely separate dedicated storage operator not be best placed to provide this? And so on.

It is important to consider how trade-offs can be managed from a system wide perspective. Determining the size of the trade-off described in the discussion might be difficult or impossible, so precisely tuning the level of risk/price exposure to match the trade-off could be unhelpful. The most cost effective solution may be simply to continue to insulate some participants from time of day prices, whilst enhancing incentives for others to respond.

References:

Chase A, Gross R, Heptonstall PJ, Jansen M, Kenefick M, Parrish B, Robson P et al., 2017, Realising the Potential of Demand Side Response - A report commissioned by BEIS, Publisher: Department for Business, Energy & Industrial Strategy.

Parrish B, Heptonstall P, Gross R, Sovacool BK et al., 2020, A systematic review of motivations, enablers and barriers for consumer engagement with residential demand response, Energy Policy, Vol: 138, Pages: 1-11, ISSN: 0301-4215.

10. What is the most effective way of delivering locational signals, to drive efficient investment and dispatch decisions of generators, demand users, and storage? Please provide evidence to support your response.

A move to a nodal (or zonal) wholesale market would clearly provide sharp pricing signals that could in theory influence both siting and dispatch decisions. The case for nodal pricing is perhaps strongest from an operational perspective in that it should provide the right dynamic real time signals to make best use of the existing fleet of assets where network capacity, branch by branch of the network, would constrain the use of certain assets. Evidence of improved operational efficiency through the introduction of LMP in other systems is given in Q11 although it should be noted much of the gains outlined relate to improving the efficient use of thermal assets, potentially of lower order significance for a future GB system. However, the importance of signalling the correct flows on, for example, interconnectors and storage assets will become an important feature as their number and capacity grows. Zonal as opposed to nodal pricing might suffice for delivering much of these operational signals.

The case for locational pricing driving efficient investment decisions is much less clear and must be considered in the context of other strong locational signals that are already present. We set out below a collection of thoughts on the limitations of nodal pricing in providing incentives to investment based on reading and discussions with a number of industry experts in GB and the US as part of an ongoing project assessing the implications of locational marginal pricing for GB. The work has been signposted in the blog by Gill et al. (2022) and will be published later in the autumn. In light of these and other challenges (see Q17) that nodal pricing would have to surmount, we recommend that other options for introducing locational signals for investment remain under consideration – including via changes to renewable support schemes and capacity adequacy mechanisms (consideration of such options is also recommended by an electricity markets expert group convened by the Climate Change Committee).

Generators: Industry has become adept at identifying viable locations for investment in renewable generation (that will dominate future capacity expansion in GB) based on locational factors other than price. These include the availability of resources, the likely ease of gaining planning consents and the ability to get a grid connection. In the offshore context in GB there are also strong steers from centrally governed leasing site auctions. Evidence from existing LMP markets suggests these signals often remain the strongest determining factors for investment. For example, development of wind in Texas has been significant but has occurred not on the back of LMP pricing but as part of centrally planned roll out of transmission connections to facilitate deployment in the most resource rich areas (Powering TEXAS, 2018)). Ensuring there is sufficient transmission capacity between the best resources and largest demand centres will remain a central challenge in delivering on net zero targets.

Within GB, it is clear that the abundant wind resource, availability of land and seabed, and favourable planning support in Scotland have provided stronger locational signals for investment there compared with many other areas of the UK. However, a lag in delivery of complementary transmission capacity for export suggests that nodal prices in Scotland under an LMP system would be zero or even negative for much of a year. In the absence of mechanisms to compensate for very low revenues, this would provide a deterrent to investment. However, excessive curtailment and failure to utilise much of the available wind energy would also be undesirable outcomes. Whether or not there exist viable alternative locations for wind or other net zero compatible technologies would determine whether locational pricing drives optimal investment or, based on an assumption of a fixed amount of transmission network capacity, simply deters necessary investment.

Cost of capital and investment hiatus risks: Exposing new assets to locational market prices would inevitably increase uncertainty and have potentially large implications for the cost of capital that must be weighed against any operational savings. Nodal prices are difficult to model with confidence in advance and are likely to expose individual areas to enhanced structural uncertainty compared with zonal or national price formation. Each new transmission-connected asset, network investment, delay in delivery of promised investment or long-term outage can have disproportionate impacts on local nodal prices. Similarly, price cannibalisation effects are likely to be even sharper at a nodal level. This places unmanageable and unpredictable risk on investors. Evidence submitted in response to Q31 suggests that removal of CfD payments and exposure to, even national, wholesale market prices has the potential to significantly increase the cost of capital for offshore wind investments. It stands to reason that exposure to nodal prices could have even starker implications for project finance. Any move to nodal pricing would likely require options to hedge and mitigate such risks. Some form of retained support scheme and options like financial transmission rights (FTRs) have been proposed but it is very unclear how these might work in practice for renewable generators. Financial transmission rights are discussed further in response to Q17.

An obvious further point is that a move to LMP would likely take years to implement and, on its own, would significantly increase revenue uncertainty for generators. This risks creating an investment hiatus at the very time investment in new capacity needs to ramp up to unprecedented levels. Whilst a move to LMP may have many theoretical advantages, it must be assessed through the lens of whether the net result would, in practice, support delivery of net zero power by 2035 and meet the expected growth in demand for electricity out to 2050.

Investment in Storage: It is often said that locational pricing would send the correct signals to storage assets allowing them to make an investment case against arbitraging locational price variations and so help alleviate local constraints. However, clear locational price variations alone may not be sufficient to enable an investment case in energy storage. Storage assets must first be able to gain network access, which may be limited in export constrained areas under current rules. In such areas, storage providers may have insufficient opportunity to get their stored energy out of the export constrained area and would thus find it difficult to make the business case. In-house modelling suggests if wind deployment in the north of the country continues to outstrip transmission development then the main constraint boundaries will bite for long periods of time. Energy storage may be able to absorb energy when generation first exceeds the ability to export from an area but if, as often happens, it remains windy for many days then the opportunity to sell and export that stored energy might not materialise for some time and so the value cannot be realised. This suggests the best tools for minimising curtailment in the export constrained areas are either additional transmission investment or an increase in demand (perhaps linked to long term energy storage).

Investment in Demand: Following from above it is often said that locational pricing is needed to incentivise new demand users like hydrogen electrolysis to locate in export constrained areas to alleviate constraints and soak up renewable curtailment. However, such load heavy industrial processes will also be subject to other external drivers for siting decisions including the desire to be close to demand for the product i.e. electrolysis may choose to locate near to industrial hydrogen clusters. Otherwise, the new hydrogen demand is reliant on the development of hydrogen transmission infrastructure, the development cost of which would then need to be balanced against the cost of simply upgrading the electrical transmission infrastructure. One important policy lesson is that assessment of the potential benefits or costs of LMP in the electricity market cannot give a complete picture without consideration of other locational factors and interactions with other sectors, including alternative energy vectors.

References:

Powering Texas, 2018. Transmission & CREZ Fact Sheet. Available at: https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf

Simon Gill, Callum MacIver and Keith Bell, 2022. Exploring the implications of locational marginal pricing of electricity. Available at: https://ukerc.ac.uk/news/locational-marginal-pricing/

11. How responsive would market participants be to sharper locational signals? Please provide any evidence, including from other jurisdictions, in your response.

Professor Frank Wolak of Stanford University has been involved in several empirical studies of the impact of locational marginal pricing, including the switch from a zonal to a nodal market design in California in April 2009. He found (Wolak, 2011) that this reduced the variable cost of gas-fired generation in California by an average of 2.1 percent, or $105 million per year. Texas made a similar change in December 2010, and Wolak and Triolo (2022), found that this reduced the operating costs of thermal generation by 3.9%. Green (2007) used a simulation study of a small-scale model of England and Wales to predict that moving from uniform to nodal prices would bring operating cost reductions and other changes equivalent to a welfare gain equal to 1.3% of generators' revenues.

Although the above studies showed reductions in the cost of production of energy from thermal generation, it should be noted that the systems studied had a very different mix of generation resources from that in Britain today or expected in the coming years, and did not take account of impacts on investment costs. Those could take two forms: benefits from siting new capacity at more appropriate locations, and costs from the higher return that investors will require to offset the greater risks described in the answer to question 10. Capital costs will dominate variable costs in the future British power system, and so the impact on these is likely to be more important than the savings described above. The impact on the operation of wind farms will depend on how output, the wholesale price and any support scheme interact to produce the generator's overall revenue, and over what timescale it is optimised.

References:

Green. 2007. Journal of Regulatory Economics, 2007, http://dx.doi.org/10.1007/s11149-006-9019-3

Wolak. 2011. American Economic Review, 2011, http://dx.doi.org/10.1257/aer.101.3.247

Wolak and Triolo. 2022. Energy Economics. https://doi.org/10.1016/j.eneco.2022.106154

12. How do you think electricity demand reduction should be rewarded in existing or future electricity markets?

The first two bullets of the discussion of demand reduction could be combined, and complemented with each of the other bullets. It will be necessary to continue to rely upon existing demand reduction/energy efficiency policies because of the numerous barriers to energy efficiency. These are well-characterised in the literature and include many non-price barriers, including poor information, access to capital, issues of trust and skills/supply chain constraints. These are a major thrust of UKERC research but all fall outside the scope of REMA. There is an overwhelming need for improved energy efficiency policies, particularly for 'able to pay' households. However, improved energy efficiency policies could be complemented by approaches within the electricity market, so our response to the options laid out in the consultation is that 'all of the above' should be kept under consideration.

Chapter 5: A net zero wholesale market

13. Are we considering all the credible options for reform in the wholesale market chapter?

☒ Yes

14. Do you agree that we should continue to consider a split wholesale market?

☒ Don't know

We differentiate between the purer form of split market defined by Keay and Robinson and the more incremental approach described by Grubb and Drummond, which we refer to as the 'dual market approach'. We refer you to the UCL submission for further detail on the latter. We fully agree that the split market approach is interesting, but also agree it is at an early stage of development and crucial design questions remain unanswered. We question the value of continuing to consider it as anything other than a long-term possibility, and note the concerns about impacts on vulnerable consumers. We also refer to our earlier points about the willingness of consumers to engage with demand response. There is a very real risk that the approach would be excessively complicated from a consumer perspective, and could fail to deliver desired outcomes from an investor perspective.

Since security of supply has long been treated as an externality it would also represent a fundamental philosophical shift if the split market system were interpreted as devolving all decisions about security of supply to consumers. The consultation document notes that this would probably not be the case, but also suggests that it would reveal consumer preference for reliable supply. Leaving aside that consumer preferences are constrained by affordability, with the poorest consumers 'preference' being forced to put up with unreliable supply (as poor consumers now underheat and constrain appliance use). If the proposition would go so far but not too far then real world constraints need to be defined. How would the approach be applied to an extended period of low wind in winter for example? Would any consumer that contracted to do so be disconnected for a period of days or weeks? If not (for example if all consumers were offered a minimum standard of reliability or would simply contract for reliable supplies from on demand whenever needed) then it remains to be seen how significant the benefits of the approach would be as a source of flexibility, or how it would materially differ from dynamic time-off use tariffs. If alternative sources of flexibility would be needed for stress events, then why would they not be used throughout the year?

The proposition as currently described also provides no indication as to how it would deliver credit-worthy contracts or de-risk investment in capital intensive low carbon assets. We agree that the proposition could in principle deliver a market separation that rewards some assets on the basis of long-run marginal cost and passes these lower costs to consumers. But as the consultation notes, the CfD does this too - in a way that investors already like, and with none of the complexity, lack of detail or potential equity implications of the split market. If the principal benefit is to offer separate remuneration streams without government intervention then it would have to be assumed that government intervention is a very problematic proposition.

If the REMA team agrees with our earlier suggestion that the post-REMA market reform process itself could proceed on a gradual basis, then it is possible that the split market approach could continue to be considered as a long-term solution. It would not be adopted until the 'build phase' of the next few years has been successfully completed. This would allow the approach to be developed properly and the viability of it to be assessed. As it stands, it is hard to reconcile the information gaps and obvious concerns about implementability with the urgency of continued progress with energy system change.

The dual markets approach is a very different proposition. As the consultation document notes this is a more incremental model that could combine continued CfD-style contracts with an enhanced set of downstream market offerings that would allow consumers to engage more with different levels of supply-side variability, and directly benefit from lower cost renewables. As it is less conceptual and more detail already exists, we suggest that the REMA team continue to consider it as a much more immediate prospect. We refer to the UCL submission for additional detail.

15. How might the design issues raised above be overcome for: a) the split markets model, and b) the green power pool? Please consider the role flexible assets should play in a split market or green power pool - which markets should they participate in? - and how system costs could be passed on to green power pool participants.

See UCL submission.

16. Do you agree that we should continue to consider both nodal and zonal market designs?

☒ Yes

See Qs 10, 11 and 17

17. How might the challenges and design issues we have identified with nodal and zonal market designs be overcome?

The REMA consultation document rightly identifies a number of challenges and design issues associated with nodal and zonal market designs and is rightly seeking evidence on solutions to those problems. We do not present any solutions but would like to expand on two points that should form part of any decision making process if nodal pricing is taken forward as a reform option.

<u>Financial Transmission Rights (FTRs)</u>
Financial transmission rights are cited, within the REMA consultation and, for example, by NGESO in their Net Zero Market Reform work as a possible solution to increased price uncertainty for generators and as a way of grandfathering existing rights and revenue streams for existing generation assets as the transition to LMP is made. The evidence we have gathered from researching and speaking to US experts suggests extreme caution is required in making the assumption that FTRs are an off-the-shelf solution for GB. Firstly, FTRs are typically noted as being a suitable tool for hedging the basis risk of baseload generation. However, their suitability for application to variable renewables is highly questionable. Evidence from the Lawrence Berkeley National Laboratory advanced in a February 2022 via an International Institute for Energy Economics (IAEE) webinar (IAEE 2022) suggests that existing FTRs (designed as fixed volume products) are not a good hedge for the basis risk of renewable generators.

Proposals for alternative variable FTRs suitable for wind generation, as featured in the above webinar seem to be at an early theoretical stage at best, and certainly untested. Significant work is therefore needed to prove that FTRs can be an appropriate device for hedging risk in a future GB system and for grandfathering rights of existing assets. One feature of FTR market design is that the amount of rights that are granted between any two nodes must form a 'feasible set' i.e. they must not exceed the network capacity between those nodes. Quite how that process is managed for grandfathering rights to renewables behind an existing transmission constraint or for a future system that has deliberately been designed to have an installed generation capacity that greatly exceeds peak demand remains unexplained. How the revenues from any grandfathered FTRs are supposed to link to, for example, lost curtailment payments for existing assets also remains unclear.

Further, from our experience in talking to US experts, FTR markets in the States have spawned a large financial industry dominated by financial institutions. This is some way away from the textbook usage for hedging basis risk in the power system which seems to be a secondary feature of the markets. These futures and derivatives markets come with significant regulatory burden to mitigate and manage the prospect of manipulation. Some FTR products, especially those traded over the longest periods of up to 3 years have proven to be very risky and a number of defaults and financial scandals have occurred. One famous example is the Greenhat scandal (Utility Dive, 2021) and these have led market monitoring bodies including in CAISO (2017) and PJM (London Economics, 2020) to highlight problematic features within their FTR markets in recent times.

Compatibility of nodal markets with net-zero

While a host of issues with LMP markets relate to the difficulty associated with the transition process it should also be noted that there are questions as to whether they remain a suitable enduring regime for electricity markets dominated by variable renewables and new forms of flexibility. If the planned energy transition continues (as legislated emissions reduction targets require), it is clear that GB would be further down the road to reliance on variable renewables - wind and solar - than any existing LMP markets. The evidence from the States shows LMP-based markets are constantly evolving and there is no single, complete model to follow that has evidenced compatibility with net zero electricity system operation. Even the Federal Energy Regulatory Commission (FERC) has questioned whether LMP remains the best solution for US markets going forward. In delivery of a new FERC order seeking submission from the US RTOs/ISOs on future challenges and needs, FERC Commissioner Mark Christie is quoted as saying "it is time to put the all-important question of the continued use of locational marginal pricing (LMP) in these market constructs on the table for serious scrutiny and discussion" (FERC, 2022).

Some academic opinion also doubts the future of LMP markets and proposals for alternative models for net-zero 2050 compatible market designs are under development, e.g. the Linked Swing Contract market design (Tesfatsion, 2022).

References:

CASIO. 2017. Problems in the performance and design of the congestion revenue right auction. Available at: https://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

FERC. 2022. Commissioner Christie's Concurrence in E2 Related to Questions for RTO/ISO Reporting Concerning Market Constructs. Available at: https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-e2-related-questions-rtoiso-reporting

IAEE. 2022. Rethinking the Role of FTR for Renewables. Available at: https://www.youtube.com/watch?v=AQQNDqo1iqw&ab_channel=IAEE

London Economics. 2020. Review of PJM's Auction Revenue Rights and Financial Transmission Rights. Available at: https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/postings/lei-review-of-pjm-arrs-and-ftrs-report.ashx

Tesfatsion, 2022. Transitioning to Linked Swing-Contract Wholesale Power Markets for Net-Zero 2050. Available at: https://www2.econ.iastate.edu/tesfatsi/LinkedSwingContractMarketDesign.LTesfatsion.FERC2022.pdf

Utility Dive. 2021. FERC orders GreenHat, traders to pay $243M for alleged PJM market manipulation. Available at: https://www.utilitydive.com/news/ferc-greenhat-traders-kittell-pjm-ftr-market-manipulation/609628/

18. Could nodal pricing be implemented at a distribution level?

☒ Don't know

Further research is needed to determine whether nodal pricing on distribution networks is feasible or desirable and at what voltage level.

19. Do you agree that we should continue to consider the local markets approach? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.

☒ Don't know

We believe that the approach needs to be appraised with full recognition of the diversity of circumstance in different parts of Britain. We note that much of the UK population lives in large conurbations, where distributed generation would be largely confined to rooftop solar. For solar, the GB resource base is very unevenly distributed by time of year, with limited resources available during winter. We also note that some relatively remote and sparsely populated parts of Britain offer large renewable resources that exceed local demand. Some regions may offer opportunities to meet local demands using local resources. Parts of the West

Country may be good examples. However, it is not immediately obvious that such regions are particularly typical of the mix of demand and resource availability that GB power market arrangements need to satisfy. Given the urgent need to develop renewable resources there is a risk that trying to develop and implement local markets distracts from more important priorities, in particular the need to ensure that network capacity allows the GB market to benefit from large wind potential constrained by transmission grid capacity. Since it will still be vital to deliver reliable energy supplies to large urban areas with limited renewable potential, network upgrades appear to be a more pressing priority.

This said, distribution network capacity may already be a constraint on both distributed generation and the roll-out of EVs and electric heat. Local institutions and governance arrangements may also hinder the development of localised solutions (including low carbon district heat). Overall, we agree that the role of local government and distribution networks are important areas for research and policy development. This is more wide-ranging than the remit of REMA. The rationale for local markets could be enhanced if GB policymakers wish to reconsider the role of rooftop solar. Doing so would perhaps benefit from a feed in tariff or enhanced export tariff that might be amenable to local trading. Based on the current state of knowledge there is little evidence to suggest that a focus on local markets would deliver a least cost outcome. As a result, assuming resources are limited, it is difficult to recommend that REMA makes local markets a high priority.

20. Are there other approaches to developing local markets which we have not considered?

☒ No opinion

21. Do you agree that we should continue to consider reforms that move away from marginal pricing?

☒ No

The Office of Electricity Regulation consulted on this question in the early-mid 1990s and concluded that pay-as-bid had only disadvantages. The Review of Electricity Trading Arrangements was based on the misapprehension that gas-fired stations were “wrongly” benefiting from higher Pool prices set by coal-fired generators, and that this would change if the centralised Pool was abolished and replaced with decentralised trading (which would naturally be based on pay-as-bid). Evans and Green (2005), found no evidence that the change from the Pool’s System Marginal Price to the price reporter’s Reference Price Data affected the price level. Spot prices did fall, but that can be explained by falling fuel prices, greater competition and a growing capacity margin, with the relationship between those factors and the price of power unaffected by the change in market rules. A well-known result in the economics of auctions, the Revenue Equivalence Theorem, states that any auction which is going to give the efficient allocation of goods between buyers and sellers (in our context, demand will be met by the cheapest set of power stations) will have the same expected revenue. In a competitive market based on marginal pricing, generators submit offers based on their marginal costs and the price clears at the cost of the most expensive generator needed. In one based on pay-as-bid, the theorem suggests that lower-cost generators will submit offers equal to their expectation of the market price, assuming that their output is needed. That then gives the equivalent cost to consumers (in expectation). A simple analogy from other markets is that cheap-to-produce oil from Saudi Arabia is sold at essentially the same price as hard-to-produce oil from the North Sea.

While the spot market price should continue to be based upon marginal principles, it is worth noting that for several years now, the overall revenue given to the newer renewable generators with CfDs *is* based on long-run marginal costs as bid into the auctions for those contracts, and consumers have been benefitting from the savings against current wholesale prices.

References:

Evans and Green. 2005. Why did British electricity prices fall after 1998? Available at: https://repec.cal.bham.ac.uk/pdf/05-13.pdf

22. Do you agree that we should continue to consider amendments to the parameters of current wholesale market arrangements, including to dispatch, settlement and gate closure?

☒ Yes

We are aware of suggestions recently that re-dispatch decisions by the Electricity System Operator (ESO) have been distorted by manipulation of technical parameters of generating units such as minimum on time and minimum stable generation. Similar alleged manipulation of Pool dispatches pre-NETA had also been cited by proponents of NETA. Furthermore, our understanding is that the ESO currently lacks rigorous decision support tools to help resolve the complexities of re-dispatch decisions in the Balancing Mechanism, and the lack of such tools leaves the ESO vulnerable to potential manipulations. The ESO had a large project to develop new decision support tools with a major international vendor that the vendor proved unable to deliver. We understand that, in effect, the ESO is now starting again. In addition to the impact on BM costs, this experience should provide a warning on the nature of large software projects and the challenges of numerical optimisation of practical power system operation that would be at the heart of any move to central dispatch and locational pricing. On the other hand, each party in the system that is self-dispatching will face comparable challenges in optimising its own portfolio.

23. Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?

☒ No opinion

Chapter 6: Mass low carbon power

24. Are we considering all the credible options for reform in the mass low carbon power chapter?

☒ Yes

The list appears comprehensive if not exhaustive. We are not aware of additional options that should be considered. However, we are not entirely convinced that all of the options under consideration are equally credible.

25. How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?

We note our earlier comments about the importance of larger scale renewables in the GB geographical context. However, the most obvious route to enhancing the contribution of small-scale options, notably rooftop solar, would be to reintroduce some form of small scale generation feed in tariff. It would also be possible to link some form of enhanced export tariff to a local market trading scheme, as noted above. Policy priorities moved away from small scale renewables (reflected in the abolition of the microgeneration feed-in-tariff), in part as a result of the relative economics of small- and large-scale schemes, but the economics of smaller scale PV will have improved in the interim.

26. Do you agree that we should continue to consider supplier obligations?

☒ No

A low carbon obligation was considered in the early stages of the EMR analysis and consultation. It was not pursued because the principal purpose of the reform was to provide a stable and low risk investment incentive. Under a low carbon obligation, like the Renewables Obligation before it, investors would continue to be exposed to wholesale market price volatility. In the future, the concern is that price cannibalisation undermines revenues to wind and solar generators. Analysis published by UKERC last year demonstrates that an approach that tracks wholesale prices exposes prospective developers to much higher levels of risk, and that the resultant cost of capital impacts add considerably to overall costs (Gross et al., 2021, see also answer to Q31). In addition, at present such an obligation would offer limited potential to help stabilise consumer bills in the face of inflated gas prices unless it could be linked to a long-run fixed price PPA. The potential for suppliers to offer such contracts is highly questionable (see answers to Q27 and 43).

A supplier obligation also lacks credibility with regards to the counterparty risk. The Low-Carbon Contracts Company ended up as a state-owned body as investors required this level of security before they were willing to finance renewable generators at a reasonable cost of capital, even though the payments routed through the company came from a legal obligation placed on all consumers by the government. Recent experience demonstrates that many suppliers were not credible counterparties for short-term commitments, let alone long-term ones.

A supplier obligation also creates coordination challenges. Would suppliers chase low-cost sites (for example offshore wind seabed leases) and bid up prices in the process? Conversely, what if suppliers collectively and periodically over deliver as we proceed through the transition, leading to a boom and bust cycle of development? How would they be incentivised to develop higher cost resources that might be strategically important for the long-term, such as floating wind. These pressures led to banding in the Renewables Obligation, undermining the original desire for a technology neutral approach. Presumably any obligation would need to have a ‘safety valve’ to avoid excessive cost to consumers (the role the Buyout Price played under the Renewables Obligation). This could create a delivery risk.

For all of these reasons we find it difficult to recommend that REMA continues to give serious attention to a supplier obligation, at least in the short-term.

References:

Gross et al., 2021. Can renewables and nuclear help keep bills down this winter? Available at: https://ukerc.ac.uk/publications/can-renewables-help-keep-bills-down

27. How would the supplier landscape need to change, if at all, to make a supplier obligation model effective at bringing forward low carbon investment?

Please see answer to Q43. The relative success of obligation-based approaches in some US states appears to correlate with the absence of retail competition. Since retail market issues are out of scope for REMA it is not possible to explore this issue further, but we are not aware of any proposal to limit or remove retail competition. Whilst many of the difficulties with an obligation described in the answer to Q26 would be removed if retail competition were ended or constrained, it does not seem all that likely that this would be a desirable outcome.

28. How could the financing and delivery risks of a supplier obligation model be overcome?

Monopoly local suppliers or constrained retail competition. See answer to Q27

29. Do you agree that we should continue to consider central contracts with payments based on output?

☒ Yes

For all of the reasons set out above we believe that central contracts are likely to be the simplest and most cost-effective way to continue to deliver low carbon power. The question may refer to a move away from payments per unit of output (alone) and we are aware of the proposition to move CfD payments to a deemed basis, as described by Prof Newbery. Whilst this is an interesting approach that has merits we don't believe that the case for a move away from payment based on output is yet made, and we do not think there is any reason *not* to continue to consider contracts based on output. In our answers to Qs30 and 31 we discuss some of the impacts of exposing CfD generators to more wholesale power price risk. These do not undermine the case for output based payment per se. Moving to deemed output could also have disadvantages. We suggest an approach that starts with incremental changes to the CfD. For example by offering opportunities to value stack by participating in ancillary services markets.

30. Are the benefits of increased market exposure under central contracts with payment based on output likely to outweigh the potential increase in financing cost?

From first principles, the relative balance between financing costs and system benefits of increased risk exposure will depend on the shape of the cost and benefit functions, which we might expect to be non-linear. In the case of the financing cost, we might expect a relatively small response to a small increase in risk, and a much larger response to large increases in risk. We provide evidence on this in answer to Question 31 indicating that financing costs for delivering offshore wind can rise by up to a third (up to £5bn / yr) with full price exposure, with various policy design options (including cap and floor mechanisms) available to reduce this financing cost penalty by moderating exposure to market risk.

If the opposite is true of the benefit function (i.e. a small increase in market price exposure produces a relatively large system operation benefit, with diminishing returns on larger increases in risk exposure), then in theory there could be a sweet spot where an overall system cost benefit can be achieved by exposing projects to moderate levels of market price risk.

However, further evidence is needed on this latter point. If, in order to achieve system operating benefits, projects specifically need greater exposure to low-price episodes (rather than say exposure to mid-range price variation), then there is more likely to be direct tension between financing costs (which respond precisely to exposure to these low-price events) and system operation benefits. This would make it harder to find the sweet spot of overall system cost savings.

31. Do you have any evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms?

The following evidence is based on results presented in UKERC Working Paper "Risk and Investment in Zero-Carbon Electricity Markets" (Blyth et. al. 2021), supplemented with additional simulation results to be published in a forthcoming UKERC briefing paper.

Final investment decisions on large-scale power sector infrastructure such as generation and interconnectors are taken many years before the plant actually become operational. Expected revenues therefore depend on forecasts of electricity price. Such forecasts are subject to increasing levels of uncertainty as the system progresses through the decarbonisation process. This is due to uncertainty over the way the system as a whole will respond to increasing penetration of variable renewables.

Price behaviour in wholesale markets (e.g. the degree of price cannibalisation and price volatility) will depend on both the mix of generation, and the degree and type of flexibility of the system. The latter in turn depends on both large-scale infrastructure investments as well as non-infrastructural shifts such as behavioural change. Pathway uncertainty over how the physical system will evolve to low carbon means that the price behaviour in wholesale markets has corresponding structural uncertainties, creating financial risks that are hard for market participants to effectively manage down. One would therefore expect that these additional risks would pass through to the cost of financing.

Different policy design options provide varying degrees of protection from these market price risks. In the paper cited above, we quantify cost of capital effects of market price risk exposure under different policy design options using the following steps:

i. Represent different physical scenarios for a decarbonised GB electricity system in an optimal dispatch model

ii. Calculate the differences in dispatch and marginal pricing between these scenarios to represent the degree of risk that an investor faces over the future state of the system.

iii. Model the financial performance of a hypothetical offshore wind investment in each of these potential future states of the world

iv. Quantify the degree to which the cost of capital would have to be increased to compensate for this risk.

v. Repeat the analysis for different policy designs (e.g. CfDs, feed-in tariffs, full market exposure etc.)

The results are summarised in the chart below.

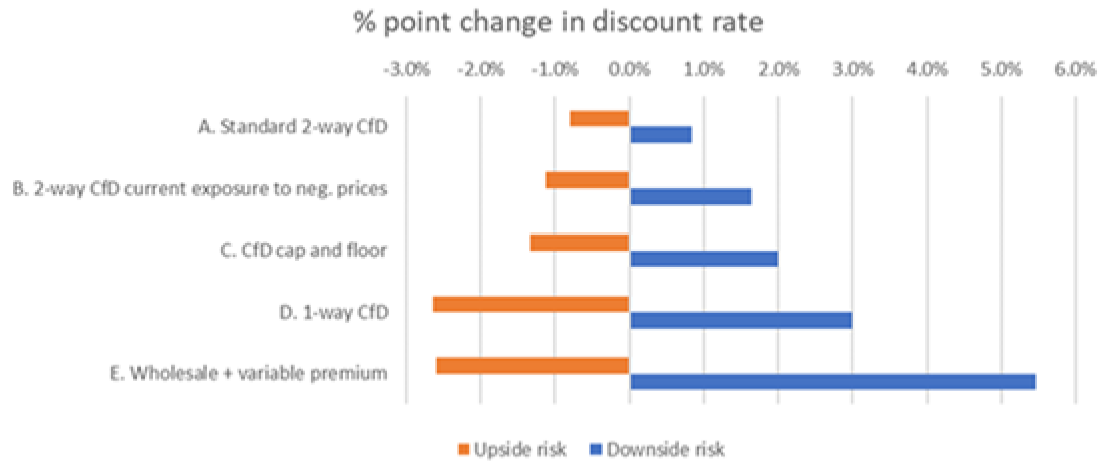

Figure 1: Risk impacts of different policy scenarios (Gross et al 2021)

Notes on the results for the different policy options presented in the chart:

A. Standard 2-way CfDs provide the lowest cost of capital by fixing prices for the duration of the contract (here assumed to be 15 years), with tail risk exposure only after that time.

B. CfDs that do not pay out when wholesale prices go negative (as per current design) lead to an additional downside risk of around 0.8 % points, but noting that CfD does pay out when prices are low but positive.

C. A cap and floor price provides symmetrical management of upside and downside risks, with exposure depending on the size of the cap-floor price gap (assumed £47-70/MWh in this modelling).

D. A 1-way price floor helps manage downside risk, but investors are still exposed if upside prices fail to materialise to the extent expected, thus reducing average returns compared to expectations.

E. Full exposure to market price uncertainty leads to a more significant impact on cost of financing.

We can put these results in context by looking at in the impact on the cost of financing the expansion of offshore wind. National Grid ESO Future Energy Scenarios include around 80 GW of new offshore wind capacity by 2040. Each % point increase in the cost of capital would add around £1bn per year to the cost of achieving this. So, for example, an increase of 5 %-points due to greater market price exposure would increase the total cost of financing 80 GW of wind from £15bn per year in a low-risk case to £20bn per year, an increase of 33%.

The results also show that the stronger the price floor component of the policy, the greater the effect on keeping financing costs low. The strongest case is a standard CfD (Case A) with no price exposure. A symmetrical exposure to mid-range price variation through a cap and floor approach (case C) incurs a relatively modest degree of penalty in terms of increased capital costs compared to a simple 2-way CfD arrangement.

Conversely, exposing projects specifically to low price events could have a much greater impact on financing costs. We can see this from the relatively significant difference in financing cost between case A (standard CfD with fixed prices) and case B (where projects are not remunerated when prices are negative). These negative price events only occur around 3-9% of the time in our simulations, but uncertainty over the frequency and duration of these events still has a quite sizeable (0.8 % points) impact on financing cost. If projects were to be exposed to low-price events as well as negative price events, this could cover a much larger number of hours and therefore have a correspondingly larger impact on financing costs.

This research only addresses the financing cost part of the question. Further evidence is needed on the potential system benefits of market price exposure. In particular it will be important to understand whether these benefits are likely to accrue evenly across the whole range of price variation. If, for example, system cost benefits only accrue when VRE plant are exposed to low prices, then there will be direct tension between the financing costs vs system operation benefits. In this situation, moderate exposure to mid-range price variations through a cap and floor arrangement might not achieve much in terms of system cost improvement and may therefore not be worth the additional complexity.

32. Do you agree we should continue to consider central contracts with payment decoupled from output?

☒ Yes

In some respects, this is the inverse of our answer to Q29. Payments based on deemed output offer some advantages. We do not believe the case is made but the idea deserves further consideration.

33. How could a revenue cap be designed to ensure value for money whilst continuing to incentivise valuable behaviour?

The remuneration in the Danish Offshore wind tendering system is based around produced electricity over the lifetime and not limited to a fixed time period. This allows wind farms to be curtailed in times of high national wind output, without forgoing revenue from the tendering system (Jansen et al. 2022 https://doi.org/10.1016/j.enpol.2022.113000). With the latest iteration for the Thor tender, a financial cap for both counterparties (i.e. wind farm and state) was also implemented, limiting financial flows in either direction. In the UK context, this could be applied as well, setting a target CfD length of 15 years, based on a reference turbine design. Alternatively, one could reduce the hours per year during which support is paid. By capping this to e.g. 90% of the year, the operator will use the most valuable hours to operate the turbines. Either way, this does require changes to the CfD tendering, and has some implications on how the Crown Estate bidding rounds are conducted.

References:

Jansen et al. 2022. Policy choices and outcomes for offshore wind auctions globally. Available at: https://doi.org/10.1016/j.enpol.2022.113000)

34. How could deemed generation be calculated accurately, and opportunities for gaming be limited?

It would be possible to base "deemed generation" on the actual load factors of nearby stations, using the principle of "yardstick competition". The stations would need to be sufficiently close to have the same general weather patterns, and sufficiently numerous to avoid the impact of sites with idiosyncratic behaviour (though this doesn't help a generator *on* an idiosyncratic site), or distorted incentives for co-owned stations.

Another approach is to measure the power available signal from wind turbines (National Grid ESO, 2021). This could be derived from wind speed measurements (external of from the nacelle) or using wind turbine rotational speed and blade pitch angles. Whilst these approaches yield reasonable results (Göçmen et al. 2018), there is still room for improvement. Whilst this method would be usable for plausibility checks (over longer time spans), it is debatable whether a different policy design could more easily discourage gaming, for example, by limiting the overall production or money paid to a wind farm, as implemented in Denmark.

References:

Göçmen et al. 2018. Possible power of down-regulated offshore wind power plants: The PossPOW algorithm. Available at: https://onlinelibrary.wiley.com/doi/full/10.1002/we.2279

National Grid ESO. 2021. Power Available phase 2 further unlocks the potential for variable generation to provide balancing services. Available at: https://www.nationalgrideso.com/news/power-available-phase-2-further-unlocks-potential-variable-generation-provide-balancing

Chapter 7: Flexibility

35. Are we considering all the credible options for reform in the flexibility chapter?

☒ No opinion

UKERC has just initiated new research into options for providing flexibility and the policy options each might need. Happy to share research with BEIS. Until then we do not feel confident that the full range of flexibility options is identified.

36. Can strong operational signals through reformed markets bring forward enough flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment? Please consider if this differs between technology types.

It is highly unlikely that operational signals will be adequate for all providers of flexibility. New sources of flexibility such as batteries have been brought forward principally through innovations in the ancillary service markets. These started with tenders for Enhanced Frequency Response, which offered prospective developers a defined and largely de-risked revenue stream, provided their tender was successful. Successive refinements of the product increased risk exposure, and as battery providers gained experience and expertise they have been able to continue to participate. Storage operators tell us that they could never have entered the market without the less complex and lower risk early stage EFR. They also tell us that their value stack still relies principally on system service provision rather than arbitrage, and that high overall prices do not improve the economics of storage.

It is unwise to assume that even for now well-established providers an energy-only approach is likely to be successful. For alternative providers, such as demand response this seems unlikely too. More important, some new sources of flexibility are much larger scale and more capital intensive. Technologies may be well proven, for example pumped hydro, but this does not mean that they can raise large amounts of capital on the basis of energy arbitrage alone. Large projects almost certainly require additional de-risking. They resemble both interconnectors and renewables schemes in this regard. However, unlike wind and solar they benefit from energy price fluctuations (as interconnectors benefit from price differentials). For all of these reasons a cap-and-floor approach seems sensible.

As is noted in the consultation document, providers of ‘flexibility’ currently rely on ‘revenue stacking’, i.e, income from selling different services, to cover their costs. That is likely to continue to be the case as it is unlikely that any single energy market or service mechanism on its own will suffice to drive the investment in the resources needed to meet demand for electricity sufficiently reliably. As one example, revenues from energy arbitrage are proportional, not just to price differences but to the number of times those price differences can be exploited. That presents a challenge for owners of storage of energy or low carbon fuels in sufficient volumes to cover risks to meeting demand associated with multi-day wind droughts, which occur infrequently. In addition, while reduction of peak power demand through time-shifting of demand helps reduce the volume of capital assets required for the meeting of peak demand, it does not change the amount of energy required.

Further challenges are as follows:

- Energy storage resources located in other countries - such as hydropower in Norway - could be extremely useful to Britain but access to them is complicated by access to and trading of energy across interconnectors and competing demands for those resources.
- The reliable meeting of ‘residual demand’, i.e. the difference between demand at a particular time and the power from variable renewables available at that time, depends not just on power rating but also on energy capacity, i.e. the ability to continue to meet power demand over a significant period of time. The Capacity Market at present takes minimal account of the latter dependency.
- Utilisation of ‘flexible resources’ located on the distribution network might be constrained by distribution network limits, leading to a need for clear coordination of management of the impacts of both distribution and transmission congestion on ‘whole system’ need for flexibility.

37. Do you agree that we should continue to consider a revenue cap and floor for flexible assets? How might your answer change under different wholesale market options considered in chapter 5 or other options considered in this chapter?

☒ Yes

Revenue cap and floor appears likely to be the most cost effective and practical means to bring forward large-scale storage. As set out in the answer to Q36 large scale storage has many of the attributes and financial requirements of interconnection. Such assets are likely to offer cost effective benefits to the system for decades, but it is unlikely/impossible that arbitrage and ancillary services markets will be adequate to the financing challenge posed by these large-scale schemes.

39. Can a revenue (cap and) floor be designed to ensure effective competition between flexible technologies, including small scale flexible assets?

Possibly, if it is desirable to do so. The competition has to be between assets with similar characteristics, such as overall scale/materiality, energy-to-power ratios and capital intensity. They may differ in terms of technology maturity. Innovation support should be considered separately. Whether cap-and-floor is needed or desirable for small-scale assets is unclear. Battery storage is already being brought forward through ancillary service contracts in particular, reflecting fast response times and high power. However, such schemes are not designed for longer term energy flow. There is every reason to consider a technology-neutral approach to procuring storage through a cap and floor system, provided the system services required are clearly specified and that small scale or other approaches are able to deliver them. It is also important to ensure the small-scale assets are not constrained by network or distribution/transmission issues.

It is also important to be clear that materiality and scale matter. A small number of large scale storage schemes have the potential to offer significant system value. A large number of small scale schemes may offer equivalent value, though this would depend on factors such as lack of network constraints and coordination. A small number of small schemes would not offer significant system value. As a result, it is important that the potential for a small number of small schemes to underbid prospective large schemes, leading to non-delivery of the latter, is avoided.

40. Do you agree that we should continue to consider each of these options (an optimised capacity market, running flexibility-specific auctions, and introducing multipliers to the clearing price for particular flexible attributes) for reforming the Capacity Market?

☒ Yes

41. What characteristics of flexibility could be valued within a reformed Capacity Market with flexibility enhancements? How could these enhancements be designed to maximise the value of flexibility while avoiding unintended consequences?

There are aspects of ‘flexibility’ that are needed to support the electricity system’s operation in respect, simply, of energy balancing: the ability to change the injection of power into the GB network or drawing of power from it quickly and at short notice; the ability to plan, with confidence, production or use of power hours to days ahead; and the ability to continue to produce or use power for a period of hours to days, such as during a wind drought. No single resource type – aside, arguably, from interconnections to other systems with favourable characteristics – has all of those features. However, relative to the typical form of a technology, some might be able to provide them at higher capital cost (such as the ability for nuclear power stations or gas plant with CCS to flex their output, or of pumped hydro stations to maintain a certain level of output).

In principle, a suitable structure of trading of energy, e.g. centralised dispatch markets with very short settlement periods, might encourage provision of a suitable mix of flexibility features. However, as we have discussed elsewhere, it is far from certain that short-term price signals will provide a solid enough basis for investment in all of the required types of asset. Specific market mechanisms, such as a modernised capacity market, might be required.

Other ‘flexibility’ services needed by the system include the ability to regulate voltage via the control of reactive power, and to provide short circuit current. NGESO has recently been experimenting with specific market tenders to acquire these services:

‘stability pathfinders’. However, resources that are already connected or due to connect to the system might also be able to provide them. A basic capability to provide certain kinds of behaviour is required by the Grid Code. This can often be delivered at minimal cost because the capability is inherent to the type of equipment being used, such as a synchronous generator’s ability to provide short circuit current. A basic question to be asked is what approach would represent best value to the consumer: strengthened Grid Code requirements; installation of new assets for specific system services (either through a market-based arrangement or a regulated asset base approach); or the development of a market in which assets connecting to the system for the purpose of buying or selling energy can offer enhanced behaviour in competition with service-specific assets.

42. Do you agree that we should continue to consider a supplier obligation for flexibility?

☒ No

As long as some of the options for flexibility require investment, their cost-effective support requires counterparties able to credibly take on long-term commitments. The Low-Carbon Contracts Company ended up as a state-owned body as investors required this level of security before they were willing to finance renewable generators at a reasonable cost of capital, even though the payments routed through the company came from a legal obligation placed on all consumers by the government. Recent experience demonstrates that many suppliers were not credible counterparties for short-term commitments, let alone long-term ones.

43. Should suppliers have a responsibility to bring forward flexibility in the long term and how might the supplier landscape need to change, if at all?

☒ No

This is not the responsibility of suppliers and it is difficult to envisage it being delivered effectively by the current retail market. The consultation paper stated that 31 US states had Renewable Portfolio Standards with varying degrees of success – how many of the successful ones also have retail competition? A monopoly supplier is certainly going to be a more credible counterparty than one whose customers may be bid away by rivals, and will also be more willing to take on long-term commitments.

Chapter 8: Capacity Adequacy

45. Are we considering all the credible options for reform in the capacity adequacy chapter?

☒ No opinion

46. Do you agree that we should continue to consider optimising the Capacity Market?

☒ Yes

As we discussed in our answer to Q36, the capacity market at present takes little account of the need for energy, not just power, under critical conditions. (Note that 'power' in the strict physical sense means the rate of production, use or, more accurately, conversion of energy between different forms). If the capacity market as it is framed at present is the only means of ensuring sufficient supply to meet demand during an extended winter wind drought, there is a grave danger that the need will not be met. As discussed in our answer to Q41, other features of 'flexibility' are also required. As we noted in that answer, different mechanisms to meet need can be envisaged such as particular configurations of a centralised dispatch of resources, specific markets for particular behaviours that are useful to operation of the power system, or Grid Code requirements obliging certain capabilities from different classes of equipment connecting to the network.

47. Which route for change - Separate Auctions, Multiple Clearing Prices, or another route we have not identified - do you feel would best meet our objectives and why?

☒ No opinion

48. Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?

See our answers to Q41 and Q46.

50. Do you agree that we should continue to consider a strategic reserve?

☒ No

Standard analysis of electricity wholesale markets (e.g. Joskow and Leautier in the Elgar *Handbook of Electricity Markets*) shows that if there is a "missing money" problem, in that peak prices are not providing sufficient revenues to remunerate the efficient amount of capacity, then all stations will suffer a similar shortfall (in expectation). A good reference on this is Joskow (2008). Capacity markets and reliability options increase revenues for all eligible stations, which makes sense. A strategic reserve will increase revenues for the small number of stations in the reserve but does not provide any incentives to keep the rest of the industry open. This suggests a risk that the reserve would have to grow ever-larger over time.

References:

Joskow. 2008. Capacity payments in imperfect electricity markets: Need and design. Available at: https://doi.org/10.1016/j.jup.2007.10.003

53. Do you agree that we should continue to consider centralised reliability options?

☒ No opinion

54. Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.

ISO New England has used centralised reliability options for many years. Their advantages are described by Cramton and Stoft (2005) in a piece entitled “A Capacity Market that Makes Sense”. They offer a hedge to both generators and consumers, because if the margins for selling electrical energy turn out high, payments under the reliability option are reduced ex-post. They also reduce any incentive to exploit market power (though this is not a significant issue in Great Britain at present).

References:

Cramton and Stoft. 2005. A Capacity Market that Makes Sense. Available at: https://doi.org/10.1016/j.tej.2005.07.003

56. Do you agree that we should not continue to consider decentralised reliability options / obligations? Please explain your reasoning, whether you agree or disagree.

☒ Yes

There will always be a temptation for suppliers to under-procure capacity, just as there was apparently an incentive for some of them to under-hedge their wholesale purchases during 2021, with unfortunate results. The risks here are asymmetric – insufficient capacity leading to power cuts creates costs that are far higher than the risk of paying for slightly more capacity than is needed because the system operator is institutionally cautious.

58. Do you agree that we should not continue to consider a capacity payment option? Please explain your reasoning, whether you agree or disagree.

☒ No opinion

59. Do you agree that we should not continue to consider a targeted capacity payment / targeted tender option? Please explain your reasoning, whether you agree or disagree.

☒ No opinion

60. Do you agree with our assessment of the cost effectiveness of a targeted capacity payment / targeted tender option, and the risk of overcompensation? If not, why not?

☒ No opinion

61. Are we considering all the credible options for reform in the operability chapter?

☒ No opinion

62. Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable?

☒ No opinion

63. Do you support any of the measures outlined for enhancing existing policies? Please state your reasons.

☒ Yes

A streamlining of "products" for the CfDs, wholesale market and ancillary services markets is essential to achieving an optimal "handover" from the longest-term market (PPAs, CfDs, Futures, Forwards), to short-term markets (day ahead wholesale spot markets) to real-time market (balancing markets, frequency response). Most crucially, a disparity between the product lengths in the different markets could lead some grid assets to abstain from providing their full capability to the grid (Jansen 2016).

References:

Jansen. 2016. Economics of control reserve provision by fluctuating renewable energy sources. Available at: https://www.zhb-flensburg.de/dissert/jansen-malte/

66. Do you think that the CfD in its current form discourages provision of ancillary services from assets participating in the scheme? If so, how could this be best addressed?

☒ Yes

The purpose of the UK CfD is to reduce wholesale market price exposure (Beiter et al. 2021). With little price risk exposure, there is no direct incentive for the generator to explore alternative income streams during low wholesale price. This makes the UK CfD setup an outlier amongst western CfD tendering schemes (Jansen et al. 2022).

A more flexible CfD setup, e.g. for a specified amount of electricity produced, could address this problem on the generator side. At the same time, unhelpful framing of ancillary service markets may prevent access for intermittent generators, with long product lengths or early gate closure times. As a result we recommend evaluating both the changes that the CfD scheme needs in order to enhance the potential to provide ancillary services, and also whether the ancillary service market set up is likely to impede participation irrespective of changes to the CfD.

References:

Beiter et al. 2021. Toward global comparability in renewable energy procurement. Available at: https://doi.org/10.1016/j.joule.2021.04.017

Jansen et al. 2022. Policy choices and outcomes for offshore wind auctions globally. Available at: https://doi.org/10.1016/j.enpol.2022.113000)

67. Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? If so, how could this be achieved?

☒ Yes

Please see our answers to Q36 and Q41.

68. Do you think that co-optimisation would be effective in the UK under a central dispatch model?

☒ No opinion

Chapter 10: Options across multiple market elements

69. Do you agree that we should not continue to consider a payment on carbon avoided for mass low carbon power?

☒ Yes

We have comments on useful learnings from the Dutch experience but this does not amount to considering a payment on carbon avoided. See Q71.

70. Do you agree that we should continue to consider a payment on carbon avoided subsidy for flexibility?

☒ No opinion

We struggle with the immediate relevance of a scheme designed with quite different objectives to incentives for flexibility in the GB market. The consultation does not explain why BEIS is minded *not* to pursue a Dutch Auction for low carbon power (which directly reduce carbon), but *is* minded to continue to consider it for flexibility (which may not directly save carbon at all). We can see that replacing fossil fuel flexibility, such as gas plants, with storage or other options would reduce emissions. However, it is not obvious why a CO2 saving metric would be adopted for these options but not others (demand reduction, low carbon generation). We have not considered this option in detail, but there is no obvious rationale for moving to a CO2 saved (and presumably competition with non-power solutions) approach makes sense for flexibility providers in particular.

71. Could the Dutch Subsidy scheme be amended to send appropriate signals to both renewables and supply and demand side flexible assets?

For bulk low carbon power, such as offshore wind, the UK has a winning formula that has supported continued growth. It has enabled the decarbonisation of the energy system. Changing the direction of this funding scheme would require careful readjustment, and it is unlikely to yield a superior outcome. This in the context of Dutch wind farms consistently bidding zero in offshore wind auctions, leaving them only with market revenue. The support therefore is limited to site exploration and grid infrastructure, but not in energy payment. We advocate for an evolution of the UK CfD scheme, rather than a radical overhaul. This has the benefit of maintaining continuity. That said, the Dutch scheme does offer important avenues for further development. With zero bids now the norm in the Netherlands, the legislator sought to distinguish bidders by other attributes, other than the bid price (which is zero anyway). This had led to a “beauty pageant” of bidders, showcasing their added benefits (Jansen et al. 2022). In the latest iteration of the Hollandse Kust tender this meant that Shell and Eneco have promised to build not just a 759 MW offshore wind farm, but also a 200 MW electrolyser in the port of Rotterdam by 2024, and demonstrate offshore solar PV from 2025 onwards, and include a battery storage to reduce the impact on the electricity grid. Additional announcements in Germany (Federal Ministry For Economic Affairs And Climate Action, 2022) and Denmark (Offshore WIND, 2022) show the trend of moving auctions away from an auction based solely on cost of energy, and adding flexibility and/or environmental benefits in addition to competitively priced power auctions.

We suggest the UK government considers the tendering of Power+X auctions as well, alongside the existing successful CfD auctions.

References:

Federal Ministry For Economic Affairs And Climate Action. 2022. Economic Affairs Ministry promotes offshore hydrogen: promulgation of Ordinance on auctioning sites for offshore hydrogen production. Available at: Https://Www.Bmwk.De/Redaktion/EN/Pressemitteilungen/2021/09/20210924-Economic-Affairs-Ministry-Promotes-Offshore-Hydrogen-Promulgation-Of-Ordinance-On-Auctioning-Sites-For-Offshore-Hydrogen-Production.Html

Jansen et al. 2022. Policy choices and outcomes for offshore wind auctions globally. Available at: https://doi.org/10.1016/j.enpol.2022.113000

Offshore WIND. 2022. Denmark Working on World's First Power-to-X Tender. Available at: https://www.offshorewind.biz/2022/09/12/denmark-working-on-worlds-first-power-to-x-tender/

72. Are there other advantages to the Dutch Subsidy scheme we have not identified?

☒ No opinion

See above.

73. Do you agree that we should continue to consider an Equivalent Firm Power auction?

☒ No

The EFP auction is based on the correct idea that we need to take account of reserve, response and system balancing when deciding on the capacity mix (however that is decided). It may also make sense to attribute such costs to the generators that 'cause' them, or at least to account for such costs in appraising overall economics. However, as the consultation paper states, deciding how much firm capacity is needed by each variable generator is likely to be a very difficult problem, particularly as the overall level of firm capacity required depends on the interaction between demand and various kinds of variable renewable generation on the system as a whole. There is a reason that in *every* power market around the world, reserve and the like are provided centrally by the system operator - it would be impossibly complex for every generator to procure their own reserve, and the amounts procured would almost certainly not add up to the amount that the system requires.

It *might* be possible to design monetary payments for “firming up” a variable generator’s output, based on the cost to the power system as a whole and the characteristics of that generator, either *ex ante* or as revealed by its actual generation. This would create an incentive to recognise those costs and build generators that cause fewer of them, though it could also raise those generators’ risks (particularly with *ex-post* payments). It is possible that the combination of receiving a “plain vanilla” CfD strike price and paying an *ex-post* charge of this kind would actually be equivalent to the generator receiving a more sophisticated set of market prices which actually reflected the value of its output (implying “revenue cannibalisation” at times of high collective renewable output, for example). If this would raise risks to an unacceptable extent, perhaps an *ex-ante* version would provide adequate signals. However, designing this system would be complex. One reason for that complexity is that costs in a power system are very sensitive to the state of that system. For example, more reserve will be required once Hinkley Point C is running, because the size of its units means that the largest single infeed loss has risen, and there must be enough spinning reserve to cover this. Do we want to levy a charge on the operators of Hinkley that reflects this, and then charge Sizewell B (the second-largest infeed) when Hinkley is not generating?

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