UCL Institute for Sustainable Resources

Review of Electricity Market Arrangements:
Second Consultation

Response from UCL Institute for Sustainable Resources
June 2024

Summary and Recommendations

Our analysis and response focused upon two main areas from the consultation:

Challenge 2: Investing to create a renewables-based system at pace; and

Challenge 3: Transitioning away from an unabated gas-based system to a flexible, resilient decarbonised electricity system

We note that at least for supply-side investments (e.g. large-scale renewables, gas-related, and grids), REMA reforms are relevant primarily to investments that would operate from about 2030. This is due to the unavoidable time-lags in finalising REMA decisions and moving then to legislation, to policy implementation, to new auctions, and then project final investment decisions, construction and commissioning.

Challenge 2. We present some new quantified analysis to illustrate the scale of the challenge faced in particular by wind energy investments for post-2030 operation and the 'incremental' CfD reform options. From this, we conclude *inter alia* that **the most essential objective for REMA reforms is to maximise system investment in storage and flexibility. Specifically, medium-duration 'absorption' flexibility (capacity to utilise otherwise excess generation, potentially over periods of several hours to several days), is required at scale alongside securing accelerated renewables investment especially for the post-2030 period.**

We also conclude that **there is no viable 'incremental' policy option**: the existing structure of CfDs fundamentally could not deliver the required investments, because of the extent to which revenues to generators would be curtailed at times of likely negative wholesale prices. We have identified significant challenges to the options of 'Deemed CfDs' and 'Capacity-based CfDs': the REMA document outlines some of these challenges, but not how they could for example impact needed investments in storage across the system. The proposed variants could also pose major political challenges.

Challenge 3. **We conclude that the REMA analysis has likely exaggerated the need for new unabated gas power investment.** The mechanism of relying on the system-wide Capacity Market to procure new gas investment could also introduce a significant disincentive to market-based investment in the low carbon storage and flexibility that is becoming the central need for a viable zero carbon electricity system. REMA has likely underestimated the scope for combination of incentives to bring forward investment in low- or zero-carbon alternatives, including gas plants fuelled by 100% hydrogen and gas with carbon capture and storage (CCS).

Overall, the individual components of REMA have clearly enjoyed extensive and careful attention in an effort to address identified challenges to the current instruments of CfDs and Capacity Market. Our concern is that these individual components, based on adjustments to current instruments, do not amount to a coherent whole. They retain a focus on large-scale supply-side developments, which may in fact have unintended consequences – most of all, on the most appropriate ways of securing the kind of innovation and investment required to maximise the flexibility required for the future low carbon system.

From this analysis, our UCL team concludes, with considerable reluctance, that the reforms proposed in REMA may be unable to deliver the stated objectives – and may even risk undermining the goal of a zero carbon electricity system. If the issues we raise cannot be adequately resolved, an urgent rethink will be required.

In this paper, we include a short Appendix, questioning REMA’s rejection of some proposals which we consider might ultimately offer better ways to address the needs of an increasingly renewables-dominated energy system, and of GB energy consumers.

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Please note that this document comprises some content updated from our formal response to the REMA second consultation, principally around Deemed CfDs. We have also added an Appendix, reflecting on the evaluation of the Green Power Pool proposal through the second REMA consultation.

UCL Institute for Sustainable Resources response to the consultation questions.

Challenge 1: Passing through the value of a renewables-based system to consumers

1. *What growth potential do you consider the CPPA market to have? Please consider: how this market is impacted by the barriers we have outlined (or other barriers), how it might evolve as the grid decarbonises, and how it could be impacted by other REMA options for reforming the CfD and wholesale markets.*

Corporate PPAs have been an option for private sector for at least two decades. They can facilitate innovation and can meet the needs of some classes of corporate purchasers. However, it is also true that to date, they remain a very small part of the contribution to the progress made in renewable electricity in the UK.

The REMA document identifies three main reasons for this, with which we concur: high counterparty risk; high transaction costs; and contract length/demand mismatches. We do not see how these can be sufficiently overcome through private sector mechanisms alone, so conclude that whatever potential the CPPA market holds, there is no evidence that it can be mainstay of decarbonising the British electricity system without some government role.

2. *How might a larger CPPA market spread the risks and benefits of variable renewable energy across consumers?*

Clearly a larger CPPA market would help. However, given the obstacles (identified by REMA) our conclusion is that such a ‘larger CPPA market’ is likely to only make a major contribution to decarbonisation if government plays a role in helping to standardise and pool PPAs, and potentially underwrite some of the risks. We were not convinced of the stated rationale for REMA dropping Green Power Pool approaches, which would be one mechanism for doing this.

3. *Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction? Please provide supporting reasoning, including any potential alternative approaches to overcoming the issues we have outlined.*

Whilst not commenting on the proposals regarding wholesale, balancing and ancillary services market reform, concerning ‘incentivising electricity demand reduction’ we note that past efforts to enhance energy efficiency by relying on traditional market incentives have typically disappointed. This was because they did not engage with the actual decision-making characteristics of most energy consumers – and an effective low-carbon transition will need to. Moreover, the proposed major reforms to CfDs, and expanded use of the Capacity Market, could weaken rather than strengthen the price signals to consumers.

Challenge 2: Investing to create a renewables-based system at pace

4. *Have we correctly identified the challenges for the future of the CfD? Please consider whether any challenges are particularly crucial to address.*

The first section of REMA contends that the issue of passing through marginal costs on to wholesale prices will not be a significant problem, because the data it presents indicates that by 2030 gas will only set prices for less than 10% of the time. This begs the question of what will set the price the other 90% of the time. We do not see substantive analysis in the REMA consultation documents directly on this crucial point. It is fundamentally relevant to CfD reform not least because of the negative price rule.

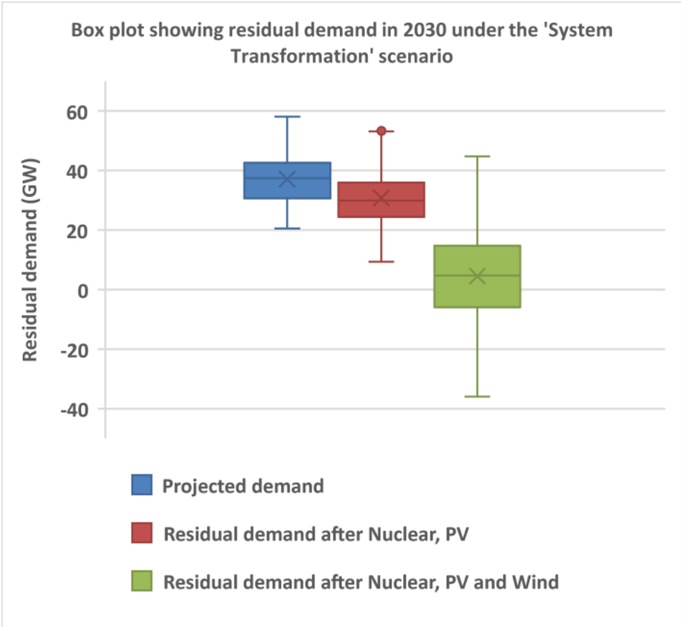
Specifically, the section on the future of the CfDs does not present data concerning the frequency with which wind energy output may exceed the system needs – leading to potential ‘cannibalisation’ of revenues.

Most of the analysis of variability has focused on the risk of periods of *insufficient* renewables generation. For investors however, the dominant question will concern the risk of *excess* generation which makes it impossible to sell their output.

A simple sense-of-scale of this is essential to understanding the nature and magnitude of the challenge to the options presented. We have sought to fill this gap, albeit partially, with data to analyse the frequency and implications of periods with potential surplus of renewable energy generation, initially for 2030 (See Box). This preliminary analysis is based on projected electricity demand and installed capacities from two of National Grid’s Future Energy Scenarios, scaling the historical hourly time-profiles of demand and different generating sources, and provides context for our answers to REMA Questions 4, 6, 7, and 8 – and relevant also to other responses.

Figure 1 gives a broad impression of the context, showing the range of variability of electricity demand, the variability of ‘net demand after nuclear and PV’, and the net demand after including also all the hourly potential output from the project wind capacity (based on underlying calculations with the distinct characteristics of onshore and offshore generation); see notes for explanation.

In the ‘System Transformation’ (ST) scenario, the average net demand after subtracting nuclear and PV is around 30GW, with a range of variation over the year 10-50GW. Including the projected total installed wind capacity of around 65GW, reduces the average net remaining demand to around 5GW, but with variations over the year close to +/- 40GW. In the most ambitions ‘Leading the Way’ (LW) scenario, there are very occasional hours in summer when nuclear and PV alone could be just sufficient to meet demand (the ‘outlier’ dots at the bottom of the whisker). With the projected high capacity of wind in the LW scenario, the median net demand is about 6 GW and the mean only 2.45GW, but the range of net demand is even larger.



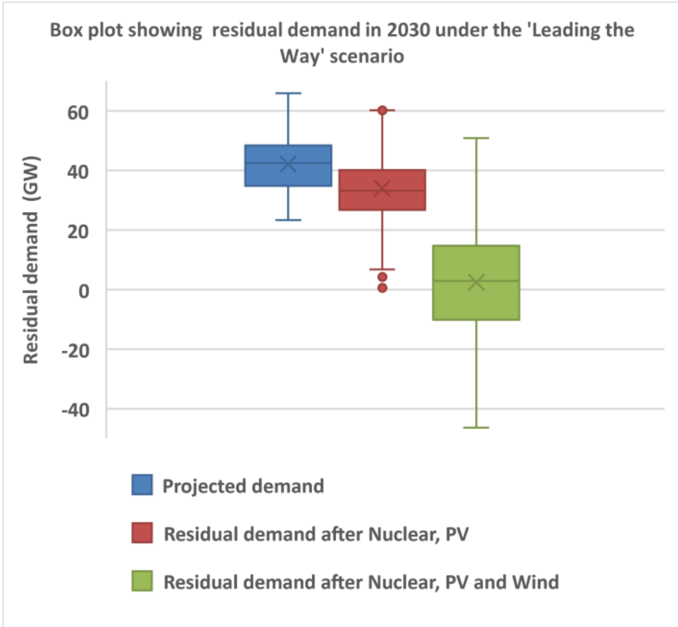


Figure 1: Level and variability of demand (blue) and the impact of deducting nuclear and PV (red), plus available wind generation (green) in National Grid FES 2030 scenarios.

Notes: The 'boxes' show the range of the central 50% of occurrences in the overall frequency of (net) demands, with the line being the median (separating the lower and upper mid quartiles of the distribution). Technically, this defines the 'interquartile range'. The 'whiskers' extends to the furthest data point in each wing that is within 1.5 times the interquartile range.

(The small dots visible for solar reflect 'outliers', associated with occurrences of high PV output at times of low demand, that lie outside this pre-defined range of the 'whiskers').

Box: Illustrative analysis to inform risks of renewables 'revenue cannibalisation'

Our analysis seeks to give simple indicators of the frequency and extent to which renewables generation in 2030 and beyond may exceed that needed to meet demand, and hence to illustrate the extent of potential risks arising from negative prices given current design of the wholesale market and CfDs.

We take the scale of annual demand and generation capacity data from two of the National Grid 2023 Future Energy Scenarios (Systems Transformation (ST), and Leading the Way (LW)), scaled to the actual hourly profiles of historical electricity demand, PV and wind output.
We assume that the projected nuclear and PV capacities operating in 2030 are 'must run', but that all other sources can be displaced by wind generation (a conservative assumptions, given e.g. other CfDs). Storage is not included and the analysis neglects interconnection (see text, noting that given the high level of wind energy capacity projected also in northern Europe, the extent of exports at times of high UK wind output is also uncertain).

Key results from this stylised analysis are summarised in Table 1 as:

		2030 System Transformation	2030 Leading the Way
Residual demand after nuclear and PV			
	Mean (GW)	30.7	34.0
	Minimum (GW)	9.31	0.622
	Maximum (GW)	54.0	61.8
Residual demand after nuclear, PV and wind			
	Mean (GW)	4.49	2.43
	Minimum (GW)	-36.0	-46.4
	Maximum (GW)	44.7	50.8
	Hours with negative residual demand	3277 (37.4%)	3855 (44.0%)
Surplus wind potential			
	As a % of total potential wind generation	14.9%	18.6%
Percentage of unconstrained output from addition 1GW wind capacity in 2030			
	Expected output at periods without surplus from pre-existing capacity (i.e. at unconstrained hours)	45%	38%
	Implied % of potential output at times of exisiting surplus (potenitally constrained-off due to -ve prices)	55%	62%

Headline findings include that:

- Compared to overall annual demand of 325 TWh (ST scenario) or 369 TWh (LW scenario), wind overall has *potential* to generate 230 TWh or 277 TWh respectively – 70% or more, if there were no constraints from transmission and variability/surplus hours
- However, even aside from transmission capacity, such output risks curtailment by the fact that in the absence of storage, the potential national generation exceeds national demand for 37% of hours in the year (ST scenario), or for 44% of hours (LW scenario)
- *If* at all such hours, the bid price were negative (see text) and wind output in excess of GB demand were curtailed, the total % of wind energy curtailed would range 15% (ST) - 18% (LW)
- This however is the snapshot across all wind in 2030: any *new* wind energy installed in that year, added to the existing capacity (with ratio 25% onshore and 75% offshore) and output, would *under the current CfD design, if these conditions of surplus led to negative wholesale prices*, earn revenues from only 45% (ST) to 38% (LW) of its 'potential' generation. This arises, of course, because the curtailed hours are precisely those with the strongest winds.

UCL will publish details of this analysis in a Working Paper.

Data sources are:

- 2017 demand data from National Grid: https://www.nationalgrideso.com/data-portal/historic-demand-data
- 2017 nuclear capacity factors from Elexon B1620: https://www.bmreports.com/bmrs/?q=actgenration/actualaggregated
- 2017 wind and PV capacity factors, scaled for current fleet characteristics, simulated using: https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract for onshore wind and PV sites. Assuming all onshore wind farms have the same turbine type (1.8 MW, 80m hub height). UKERC wind data, covering ~13GW capacity used for offshore wind capacity factors. Capacity factor simulation methodology from supplementary information of ECMWF ERA5 reanalysis weather data and methods https://www.nature.com/articles/s41560-018-0128-x
- 2023 National Grid FES (Systems Transformation, Leading the Way) to scale for 2030: https://www.nationalgrideso.com/future-energy/future-energy-scenarios-fes

The results are summarised in Figure 1 and Table 1, with key points being that wind energy in 2030 would face the following situation:

- After other 'must run' generation (represented as nuclear and PV)[1], potential wind generation would exceed demand for more than one third of the time (37% - 44% of hours across these two scenarios)
- If at all such 'surplus wind' hours, the wholesale market electricity price were negative (see below) and wind output were curtailed to match the headline electricity demand, then in aggregate 15% to 18% of the potential wind generation would be withheld (neglecting any other constraints e.g. from transmission)
- This however is the snapshot across all wind in 2030: **any *new* wind energy installed in that year subject to the CfD negative pricing rule would, with these illustrative assumptions, find that** 55% to 62% of its potential generation is surplus to **requirements,** in the sense defined here (assuming it adds to the existing capacity; assessed with a share 25:75 between onshore and offshore). This is much bigger than the hours of curtailment because the curtailed hours are precisely those with the strongest winds, so the avoided generation is much bigger than the curtailed hours alone suggest. This still does not take account of transmission constraints (or potential implications of zonal pricing).

Consequently, *under these conditions and with the current CfD design*, a new wind farm operating starting in 2030 might only earn revenues from *less than half* of its potential output in that year – from 45% (ST scenario) to 38% (LW) compared to its potential generation if there were no 'cannibalisation'.

[1] It is possible that some nuclear could flex its output; but conversely, some biomass electricity generation is supported by CfDs which would incentivise negative bidding, we take the nuclear capacity as a proxy for such sources which would bid negative prices to keep operating.

The real risk of curtailment under the current design.

Real curtailment of wind generation under new CfDs, due to negative wholesale prices, of course could be less. There are already GW of storage on the system, though the large majority of this is battery storage with duration of just a few hours, which would limit its contribution.[2] It may be possible to export surplus wind through the GB's interconnectors, though given the high level of wind energy capacity projected also in the rest of northern Europe, the extent of possible exports (and prices) at times of high UK wind output is also uncertain.

Yet, one other indication of the scale of the problem is the estimate that 30GW of capacity in 2030 would have an incentive to bid negative prices.[3] Recall also the potential level of transmission constraints, and that 2030 would be the first possible year of operation for CfD contracts established in response to REMA. The current assumption that these would operate over the subsequent 15 years – with the capacity of wind energy projected to grow rapidly, thus increasing risks of cannibalisation rapidly unless flexibility of the system increases at a corresponding pace.   It may be considered that the volume of capacity with a direct incentive to bid negative will decline (as ROC and CfD rounds 1-3 reach end of contract), but it will not help the overall drive for renewables much if new capacity simply pushes out the operation of existing capacity – and, for example, thereby deters refurbishment.

The bottom line is that, in the absence of adequate, mid-duration storage or similar capability to utilise such 'surplus' electricity, any new wind energy procured under existing CfD design that starts operating in 2030 may from its first year find that more than half of its potential output was not remunerated. If that situation comes to pass and did not rapidly improve thereafter, as a consequence, CfD bidders would have to more than double the bid price to compensate.

Before turning to the CfD reform options, we note that at system level that challenge would only get rapidly worse over subsequent years, unless the capacity to usefully absorb excess wind energy output grows at a commensurate rate. A simple illustration of this comes from comparing the stated needs for renewables capacity with the level of electricity demand projected for 2035.[4] So in response to Q4: "*Have we correctly identified the challenges for the future of the CfD? Please consider whether any challenges are particularly crucial to address."* , whilst the REMA document recognises

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[2] A cursory look at our hourly data indicate that 'surplus hours' occur in clusters, with most such periods lasting anywhere from 5 hours up to several days; storage would thus quickly be filled.

[3] . ARUP, 2020: 'Positively negative: How to capitalise on the opportunity presented by negative pricing in the British Wholesale Electricity Market'

[4] DESNZ estimate that (REMA II, p. 47) "we will need 140-174 GW of renewable capacity in 2035 to meet our carbon budget". Across the National Grid FES Scenarios, *average annual electricity demand* in 2035 ranges from 373 to 479 TWh/yr, which equates to an average level of demand ranging from 43.6 to 54.7 GW across the various FES scenarios. Of course, there is redundancy and complementarity (e.g. wind and PV rarely if ever output at peak times together), and some of the renewables are flexible (e.g. biomass). Nevertheless, this gives a sense of the extent of possible need to utilise 'surplus renewables' output – *'absorptive'* flexibility.

the qualitative nature of cannibalisation, it does not directly acknowledge the absolute scale and centrality of the issue, which is also relevant to reform options (see Q6, 7, 8).

Note also that solutions to this challenge need to separate two kinds of flexibility: namely, 'absorptive' flexibility, which can make use of surplus renewables (most obviously, adequate storage), and other flexibility. Thus, natural gas offers flexibility for meeting the security challenge, but it does not in any way help with making use of the renewables at time of surplus generation. Gas turbines *could* make such a contribution, but only if they convert to utilise hydrogen (see our response to *Challenge 3*), along with sufficient capability to generate, store and transport hydrogen generated from surplus renewables.

In economic terms, at the time of the Electricity Market Reform of 2013, the fundamental challenge to renewables investment was price risk, and CfDs have proved a brilliant instrument for tackling this. However, that very success has fundamentally changed the situation: the increasingly dominant risk for investors is volume risk.

We draw two substantive conclusions, fundamental to REMA, from this analysis.

- **There is no credible 'ongoing / modest reform'** scenario. The UK's Electricity Market Reform, initiated in 2010 and culminating with the introduction of CfDs and the Capacity Market in 2013, has been a remarkable success. However, given the scale of the transformation unleashed, fifteen years later it cannot be assumed that this implies 'more of the same'.

In rejecting some options that REMA dubs as more radical, a central argument is the need for investor confidence, which is taken to mean avoiding major change. This appears to inform the REMA incrementalist approach, which starts from a presumption to keep CfDs and the Capacity Market, and rejects potentially major structural changes (and rejects CfD options around direct revenue assurance).

The reality is that maintaining CfDs (our next section discusses the Capacity market) in anything like their current design could achieve precisely the opposite. Companies would of course very carefully analyse revenue prospects before submitting bids for billions of pounds of investment. Given the scale of potential 'cannibalisation' from surplus generation, maintaining the current CfDs would seem to risk destroying investor confidence and kill the expansion of wind energy. Reform is unavoidable.

- Before considering the CfD reform options in REMA, we emphasis our **second fundamental conclusion**. All attempts to rejig the design of CfDs are efforts to work around the fundamental economics of the system if it has rapidly increasing periods of surplus generation, with insufficient opportunities to actually utilise the generation.

Consequently, **the fundamental challenge for REMA is to enhance the flexibility of the system** - not only to ensure security of supply, but also so that the potential output from the UK's extraordinary physical potential for wind energy can actually be used in practice. That should be a primary focus of reforms.

5. *Assuming the CfD distortions we have identified are removed, and renewable assets are exposed to the full range of market signals/risks (similar to fully merchant assets), how far would assets alter their behaviour in practice?*

In general, the ability of a given wind or solar plant to vary its behaviour in response to economic signals seems very limited, compared to maximising the value of the electricity output itself. A partial exception would be if the signals changed some decisions at the investment stage – for example, location – or with a capacity-CfD, which could exacerbate the extent of exceptionally high levels of surplus generation (see *Q8*).

The same of course is not true of some other renewables (e.g. tidal, geothermal, biomass), or wind and solar integrated with storage (see also *Q7*).

6. *How far will proposed 'ongoing' CfD reforms go to resolving the three challenges we have outlined (scaling up investment, maximising responsiveness, and distributing risk)?*

We conducted a simplified quantitative analysis to determine our answer to his question. It is clearly negative, as summarised above: the 'ongoing' reforms will barely scratch the surface of the future volume risk to CfD investors.

Additionally, we note that REMA reforms need to keep in mind their potential impact on investors in the next CfD round (AR 7, 8 and maybe 9). Those investors will be looking forward. They will look at the extent to which REMA reforms may alleviate, or amplify, the risks that investments in these imminent rounds will face throughout the 2030s, most obviously in terms of cannibalisation.

7. *What specific gaming risks, if any, do you see in the deemed generation model, and do any of the deeming methodologies/variations alter those gaming risks? Please provide supporting reasoning.*

The REMA analysis has identified many of the potential gaming risks in the classical sense of the word, but has not identified two other major challenges to deemed generation, in terms of *politico-economic risk,* and *incentives for flexibility*.

Politico-economic risks. The calculations we conducted indicate that already by 2030, over half of the output from a new windfarm might be 'constrained off'. In the absence of adequate storage, under deemed CfDs, this would mean that *more than half the revenues paid to generators would not be related to their output* – and this ratio might well escalate. Of course, the overall economics are not so simple – the bids would be at much lower prices, given this revenue security.

However, we have already seen adverse headlines about constraint payments of a few hundred million pounds. The concern is that these would be dwarfed by the scale of payments ‘not to generate’ under Deemed CfDs, since (as with CfDs now), these expenditures would be added to consumer bills. It is unclear how well the politics of persistent ‘payments not to generate’ could be sustained, particularly recognising the shifting sands of UK energy politics and two election cycles by 2030.

Incentives for flexibility. The existing ‘negative pricing’ rule, whilst adopted for good reasons, already has some implications for incentives for storage across the system: it ‘shields’ the demand-side from deeply negative prices which might turbocharge incentives for downstream storage.

Deemed CfDs would seem to have potentially strong implications for storage incentives, with two main possibilities:

- As presented, CfD generators would be paid on ‘deemed’ basis for each hour, whether or not they actually generate. The existing approach to co-located storage prevents any CfD facility being able to receive strike price payments for more electricity than generated by the renewable facility (hence, preventing ‘behind the meter’ storage from being charged from the grid and then discharged as part of the CfD (see box). If taken literally with deemed CfDs, the same philosophy would mean generators foregoing the deemed CfD payments if they fill up storage. Under such an approach, deemed CfDs would therefore seem to inhibit investment in storage by some of the biggest players in the system, alongside the existing implicit removal of strong ‘negative price’ signals for other storage.
- The alternative treatment would be to provide Deemed payments including *whenever* there is no generation through the main site export meter. Generators would then have an incentive to invest in and utilise co-located storage, filling the store at their (extremely low) marginal operating cost, whilst still receiving their Deemed payments.

The latter treatment would seem preferable but would imply potential for generators with co-located storage to recover revenues far above their agreed strike prices. Indeed, during periods of low wholesale prices, said generators could receive significant difference payments (the difference between their strike prices and the lower wholesale prices), fill their store, to then sell the volumes generated during periods of far higher prices. This could risk undermining the incentives for storage across the rest of the system, a particular concern given our brief response to Q25 on the ‘market actors’. Given the central need for storage across the system, these seem to indicate additional complexities / problems with the deemed CfD model.

Deemed CfDs and co-located storage

The REMA 2 consultation document discusses some of the challenges with 'deemed generation' and (Table 5) lists six possible variations in design. It does not however mention important possible issues in relation to storage, which as our UCL consultation notes is central to a viable zero carbon system.

The CfD system already has some rules relating to co-location of storage with CfD generators. The LCCC issued "Storage Co-location Generator Guidance" in November 2021,* drawing on the government's CfD Standard Terms and Conditions. The preferred option is for storage to be registered as a separate entity (i.e. as a separate Balancing Mechanism unit). However it does allow for storage to be associated with the CfD unit directly ('behind the meter') provided that there are secure arrangements to "ensure that the unit shall only store electricity generated by the generating unit" (i.e.. not bought from the grid and resold for the strike price).

This latter provision however does not address a fundamental question for 'deemed CfDs' (since they break the link between payment and output): whether or not they could use their generation to fill co-located storage for selling later (and if so, on what terms).

If generators only ever receive payments equivalent to strike price for 'deemed' generation related to their renewable generator, they would have no incentive to invest in storage (they would just lose some money due to any inefficiencies in conversion).

For simplicity, considering the variant of '*deem generation only when reference wholesale prices are below strike price'* – which encompasses of course, potentially negative. Generators could then sell additional power when wholesale prices were higher than the strike price. If there were no constraints, the generator could receive strike price payment** for 'deemed' generation, whilst using the physical generation to fill its storage, and sell that electricity later.

This would create strong incentives for behind-the-meter storage, but would mean consumers paying both for filling the storage and discharging it (potentially both at the strike price). Moreover, this would undermine the incentive to invest in storage elsewhere in the system, since other storage across the system would be paying the retail price to fill storage – not being paid to do so.

Various 'fixes' to at least partially address this could be considered – for example, constraining the total volume of payments to the annual average 'deemed' to be generated by the renewable source. All however would come at the risk of even greater complexity.

Notes:
*https://www.cfdallocationround.uk/sites/default/files/2021-11/Storage%20Co-location%20Guidance.pdf

**when wholesale prices are negative, assuming that with deemed generation the current 'negative pricing rule' is removed, then the payment for deemed generation would presumably be at the strike price. When wholesale prices are positive (but below strike price), generators with co-located storage could potentially choose between selling to the grid or filling their storage; the deemed volume would be the same. However, presumably the price received through the LCCC could be the difference between the wholesale price and the strike price (i.e.. their 'top-up' compared to the wholesale price they would earn if they sell to the grid). This would reduce but not eliminate the problem identified.

8. *Under a capacity-based CfD, what factors do you think will influence auction bidding behaviour? In particular, please consider the extent to which developers will be able to reflect anticipated revenues from other markets in their capacity-based CfD bid.*

The capacity-based CfD was clearly introduced at a late stage in the REMA II process: the proposal is less than a page. In its raw form, it appears to be a straight government capital subsidy by another name. Also, whilst this text majors on the benefits in terms of operational efficiency (which as noted, are likely modest in the context of 'as available' wind or solar) it does not acknowledge the fundamental distortion to investment incentives: a wind farm would have incentive to place a larger generator on top of the same turbine so as to be paid more, though this would be a suboptimal design, and would exacerbate the problem of surplus generation at times of high wind.

Clearly, it could be hard to explain to the lay politician why the electricity system demands two different capacity payment processes, with neither involving payments for actual generation. It is also unclear what this would do to price-setting in a unified wholesale market and for its consumers.[5]

The 1.5 pages of 'further detail in Appendix 2' suggest the Capacity CfDs would probably need to use 'availability factors' to adjust payments. This could help to address some problems, but in general these seem to take the idea back in the direction of Deemed CfDs, with some (significant) added complications.

9. *Does either the deemed CfD or capacity-based CfD match the risk distribution you detailed in your response to Q25 on which actors are best placed to manage the different risks?*

This is an excellent question. The answer depends on 'which actors' (as highlighted in Our answer to Q25), details of design, and the overall Objective of REMA.

The deemed CfD addresses the (financial implications of) volume risk identified, by its basic principle of paying for 'deemed' output, at the strike price, whether or not that output is actually used.

Aside from possible concerns about practical viability, REMA does not seem to note some potential downsides of the proposed CfD reforms for the wider system. As indicated, deemed generation would either (a) largely destroy incentives for the generators to co-locate storage, or (b) if there were 'double payment' (strike price for 'behind the meter' filling of storage, and for generation from that storage) create risks for other storage operators across the rest of the system who would face heavily subsidised competition from the

[5] We are aware of some proposals for two-tier pricing approaches that would seek to separate long-term marginal cost of generation capital from short-term operational signals 'at the margin'. Given our previous research on a Green Power Pool approach, we also note with appreciation the attention given to a form of GPP in the REMA Options Assessment document, including the GPP 'journey map' (Figure 5). We acknowledge the REMA statement that 'the green power pool failed against investor confidence and deliverability', without necessarily agreeing with this assessment relative to other options.

CfD holders, for what is already a volatile profile of returns to storage investment.

The cost of the deemed CfDs would presumably be recovered through charges, which would also blunt operational incentives for efficient response to the variability of renewables. At the scale implied, this could also weaken incentives for renewables investment outside the CfDs (see Q13). Other system risks for deemed CfDs would seem to reflect discussions elsewhere in REMA, e.g. concerning location, akin to normal CfDs.

The capacity-based CfD is not a fully developed proposal. In principle, the thrust of it is compatible with the underlying evolution of the electricity system (and renewables) towards a system with the economics dominated by capital investment with minimal variable operating costs. The incidence of the risks associated with it for renewable generators would depend critically upon the nature and implementation of ‘availability factors’.

Moreover, with such radical changes to CfDs, REMA would then unambiguously need to consider the meaning of a wholesale market in which (as per REMA consultation, *Figure 1*) the price is being set by ‘something else’ other than gas, for more than 90% of the time. This is because it implies that almost all new investment would be paid for directly through the two Capacity markets, respectively for on-demand (‘optimised’ Capacity Market), and as-available (renewables).

If so much is being paid through capacity payments of one sort or another, with costs recovered through charges to consumers, this must have major implications for the wholesale price. This wholesale price must surely on average be much lower than without those capacity payments (unless generator profits are very much higher), with inevitable implications for investment and potentially operational incentives across the rest of the system.

This, REMA does not appear to properly consider.

13. *What role do you think CPPA and PPA markets, and REMA reforms more broadly, will play in helping drive small-scale renewable deployment in the near-, mid- and far-term?*

This question relates critically to understanding the nature of the ‘different actors’ in the system and their decision-making characteristics, and thus relates closely to our answer to Q 25 which summarises a well-established, simplified typology for characterising different decision-making drivers.

This is particularly important concerning small-scale renewables deployment, where the different decision-making domains take rather different forms from those concerning large-scale investments.

First, note that feed-in tariffs and the incentives of ROCs – also in the aftermath of the high fossil fuel prices in 2008-10, along with the crescendo of climate concerns around the Copenhagen summit – drove a wholly unexpected pace of local renewables deployment (early in the 2010s, Ofgem projected 1GW of solar PV by 2015; the reality was 10GW).

We have indicated in our response to Qs 1 and 2 a view on CPPAs. They are valuable, but there is little evidence that they can self-organise to sufficiently overcome the three obstacles that REMA notes to large-scale impact. This is for multiple reasons; and concerning small-scale renewables, the issue of network constraints on distributed generation (which capped the deployment of PV and deters many renewables today) also looms large.

At the same time, the sheer volume of the 'pipeline' of proposed small-scale renewables underlines the pent-up desire for greater deployment. Much of this is driven significantly by first-domain motivations, including:

- individual desires to enhance household contributions to environment and/or 'energy independence' (including distrust of suppliers);
- the 'transition towns' movement for community-based clean energy;
- businesses at multiple scales wanting to enhance Corporate Social Responsibility;
- major brands wanting to present as 'net zero';
- local authorities seeking to develop and deliver regional net zero goals;
- other public bodies wanting to align with climate goals (e.g. the NHS, education).

There is of course a limit to how much such actors can invest in renewables if the risks are too high, and the financial returns are too low. For a market reform programme intended to dramatically accelerate progress on renewable energy, REMA seems to pay seriously inadequate attention to such actors, their motivations and constraints, and the impact of major REMA reforms 'downstream' on the rest of the system.

Challenge 3: Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system

16. *Do you agree with the proposal that new lower emission limits for new build and refurbishing CMUs on long-term contracts should be implemented from the 2026 auctions at the earliest?*

To answer this question fully, it is necessary to examine the consultation document's assumptions about the need for flexible generation capacity in 2035 – including unabated gas plants. **Our view is that the government has overestimated the need for new, unabated gas plants – and should not support investment in such plants.**

The consultation states that 30-50GW of long-duration flexibility (more than a few hours) will be required in 2035, which includes hydrogen power plants, unabated gas, CCS power plants and long duration storage. This is in addition to a requirement for 55GW of short-duration flexibility (mainly, from batteries). In their report, *Delivering a reliable, low carbon power system*, the Climate Change Committee discuss their central scenario for 2035. This includes 17GW of dispatchable low carbon capacity and 12GW of unabated gas capacity. The unabated capacity would make 'a small contribution' to system balancing, and would account for less than 2% of annual generation. This scenario also includes 11GW of grid storage, most of which is likely to be short-duration storage.

Some of National Grid’s Future Energy Scenarios for 2023 have a higher capacity of unabated gas in 2035 than the CCC. Across four scenarios, unabated gas capacity ranges from 8GW to 46GW. The REMA consultation document only quotes the two scenarios in the middle of this range (with 25-27GW), and ignores the scenario at the lower end. By contrast, Aurora analysis for the National Infrastructure Commission only has 12GW of unabated CCGT capacity in its ‘base case’ scenario that meets 2035 and 2050 targets. In addition, it includes a further 12GW of unabated peaking plants (gas engines and OCGTs) and 9GW of gas CCS.

There is sufficient evidence across these scenarios to suggest that it will be possible to achieve the 2035 target whilst achieving a high level of reliability – and it is possible to do so with long-duration flexibility at the lower end of the DESNZ 30-50GW range.

The supporting analysis for DESNZ by Baringa states that only 12GW of the current 27GW of CCGT capacity will still be operating in 2035 under business as usual conditions. This would be in addition to 4GW of new CCGT, OCGT and gas engine capacity that already has Capacity Mechanism contracts, and an unspecified proportion of current OCGT and gas engine capacity (totalling 5GW).

A change in the capacity market rules could strengthen the business case for life extension of existing CCGT capacity. This would mean that a larger proportion of current CCGT capacity is still operational in 2035. Given this evidence, it makes sense to **lower the investment threshold for three-year Capacity Mechanism agreements** so that they provide sufficient incentive for CCGT refurbishment and life extension. This would also help to avoid investment in new unabated CCGT capacity, which will be very difficult to finance given that it will be required to operate at a low load factor.

To remove the need for new unabated gas investment entirely, the government should also ensure that there are **sufficient incentives for the early deployment of long-duration storage and power plants burning 100% hydrogen** (see response to Q18 below). This could be complemented by some gas-fired capacity with carbon capture and storage (CCS). The proposed lower emissions limit for Capacity Market agreements from 2034 will provide **a useful backstop regulation**, so that any unabated gas capacity will operate at a low and limited load factor. However, it will be important to keep the level and timing of this limit under review to ensure that power sector emissions continue to fall at a rate that is consistent with the UK’s statutory climate change targets. Higher than necessary electricity sector emissions will mean a greater need for emissions reductions elsewhere in the economy.

Finally, we note that, along with limiting emissions, an emissions limit would help to reduce competition from unabated gas displacing other flexible sources (including, absorptive flexibility to utilise surplus renewables output – including hydrogen production for use in gas turbines). However, compared to a strategic reserve, it could have complications in terms of ensuring system security: the operators would seek to maximise profits within the limits, but this leaves unanswered the question of what happens if units are needed but have exhausted their (presumed annual) limit before the end of the year, if they still rely on unabated natural gas.

18. *Considering the policies listed above, which are already in place or in development, what do you foresee as the main remaining challenges in converting existing unabated gas plants to low carbon alternatives?*

The challenges of converting existing gas plants to burn hydrogen are both technical and economic. A recent literature review by the US Department of Energy (US DoE) National Energy Technology Laboratory sets out the status of hydrogen gas turbines. It includes details of experience and development plans by the 'big three' gas turbine manufacturers – General Electric (GE), Siemens and Mitsubishi Heavy Industries[6]. All of these companies have been developing gas turbines that can burn hydrogen for several decades. Key technical challenges include higher combustion temperatures (when compared to methane), a faster flame speed and higher NOx emissions (unless they are controlled by changes in combustion chamber design). Within their development programmes, these manufacturers are also exploring the retrofit of existing gas turbines so that they can burn hydrogen.

All of the 'big three' manufacturers have **models available now which can burn up to 100% hydrogen**, though the percentage varies widely by specific gas turbine model. According to the US DoE review, GE's F and E class gas turbines (models that have been widely deployed in the UK) can already be designed to burn 100% hydrogen, whereas their newer and more efficient HA class turbine is capable of burning 50% hydrogen. Siemens can upgrade their large E and F class turbines (again, these have been widely deployed in the UK) to burn 50-60% hydrogen. By contrast, their smaller aeroderivative gas turbines – which are based on aircraft jet engines – have been able to burn 100% hydrogen for some time. Along with other European manufacturers, Siemens has committed to developing a full range of gas turbines that can burn 100% hydrogen by 2030.

The UK's policies should take into account this significant experience and progress by leading international firms. Rather than facilitating investment in new plants burning natural gas, **there is an opportunity for the UK to support plants that burn 100% hydrogen**. Just as the UK provided one of the largest 'lead markets' for natural gas CCGTs, it could also be one of the first countries to take advantage of the current wave of innovation in gas turbine technology. Initially, this may require **government innovation funding in addition to incentives through the Capacity Market**. This is to reflect the additional technological and financial risks associated with a technology that is still in the early stages of deployment.

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[6] National Energy Technology Laboratory (2022) A literature review of hydrogen and natural gas turbines: current state of the art with regard to performance and NOx control. White Paper DOE/NETL-2022/3812. US Department of Energy; https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf

19. *Do you think there is currently a viable investment landscape for unabated gas generation to later convert to low carbon alternatives? If not, please set out what further measures would be needed.*

As we note above in our response to Q16, the evidence from the government's consultants suggests that there are insufficient incentives for life extension of existing unabated gas plants. Baringa's second phase of analysis – on the economics of conversion to burn hydrogen – is not yet available. However, given that this technology is still in the process of being developed and deployed by the major manufacturers, it is unlikely that retrofitting to burn 100% hydrogen will happen without further government support. This is required to reflect the additional technological and financial risks of such retrofits.

Rather than trying to reform the Capacity Mechanism to drive retrofit investments in the short-term, we suggest a need for complementary public funding. This could, for example, provide a share of the up-front costs of one or more retrofits in the UK using different models of gas turbine from a diversity of manufacturers.

21. *Do you agree that our combined proposed package of reforms (bespoke mechanisms for certain low carbon flexible technologies, sharper operational signals, and an Optimised Capacity Market) is sufficient to incentivise flexibility in the long-term? Please set out any other necessary measures.*

In principle, the government's approach makes sense. To drive the continuing transition away from fossil fuels in the electricity system, a combination of general market signals and specific support for emerging technologies is required. A package that only includes Capacity Market reform would risk slowing down the deployment of low- or zero-carbon sources of flexibility that will be essential to operate a reliable 21st Century electricity system.

Our main concern is that the bespoke mechanisms are not strong or immediate enough to create incentives for the long-duration flexibility options that will be required to replace unabated gas. In particular, the government has overestimated the need for new unabated gas. There is a risk that this assumption will lead to reforms that continue to prioritise new unabated gas in the Capacity Mechanism. In reality, there is a need for reforms that are designed to focus primarily on life-extension of existing plants, retrofitting them (so they are low- or zero-carbon), and new investment in alternatives.

Whilst we welcome bespoke policies to support hydrogen gas turbines, long-duration storage and CCS, there is a disconnect in timing. Such policies should be driving any new investment in long-duration flexibility now, rather than waiting because of a mistaken assumption that new gas is the only feasible option in the short-term. Hydrogen is already being used as a fuel for gas turbines built by major global manufacturers, and CCS has already been deployed at scale. It is therefore essential that the government's new incentives for CCS lead to real investments as soon as possible, and that specific innovation funding is provided to support the early deployment of electricity generation from 100% hydrogen.

Moreover, and especially if the emissions limit is too weak, the Capacity Mechanism amounts to a market-wide subsidy for a major part of the UK generation fleet. Whilst this has been an effective mechanism for procuring sufficient capacity to ensure security, its extension as a system-wide incentive in effect would presumably depress the wholesale price and – more specifically – by muting the price signal across a substantial portion of UK generation, would deter market-driven investments in some established sources of flexibility, including batteries and demand-side response.

Options compatibility and Legacy Arrangements

25. *Which market actors (e.g. generators, suppliers, consumers, government) are best placed to bear / manage different types of risk?*

It is welcome to have a question recognising explicitly the different types of actors involved – this is key. However, the question is formulated purely in terms of the traditional economics of risk, when what matters for the transition is the actual behaviours of different actors involved in the transition. Because of the wide range of actors, we adopt a simple classification of key actor-decision-making categories, drawing on the 'Three Domains' structure of the book Planetary Economics and its subsequent articulation in a recent paper in the *Oxford Review of Economic Policy*:[7]

- ***Small-scale actors.***

Within the electricity system, demand is driven principally by the behaviour of individuals in around 30 million households, and in many millions of companies, ranging from sole traders to major companies, the vast majority of which are not 'energy-intensive' organisations.

The literature is unambiguous in recognising that the 'first-domain' behaviour of these actors concerning energy is, emphatically, *not* generally an active process of risk-weighted financial-return, being dominated by what economics has termed 'satisficing' behaviour. Decisions are shaped by capacity, habituation & motivation, amongst other high-level characteristics. As noted in our *Oxford Review* paper, the major failures of government policy on energy efficiency can be largely attributed to a failure to recognise, understand or engage with such first-domain behaviours.

The energy transition also potentially involves a transition in the role of consumers. This ranges from the potential for far greater consumer adoption of small-scale renewables and flexible demands (particularly in context of EVs and heat pumps, but also local batteries or other storage), to the demands of large companies like Google for efficient access to "24/7" renewables.

Energy consumers have traditionally been 'passive', but in principle, first-domain behaviours can include motivation to innovate (on both supply and demand), experimentation both with new technologies and new ways of

[7] Grubb, M., Hourcade, J.C. and Neuhoff, K. (2014) Planetary economics : energy, climate change and the three domains of sustainable development. Routledge; and Grubb M, A. Poncia, P, Drummond, J-C. Hourcade, and K. Neuhoff, 2023) 'Policy complementarity and the paradox of carbon pricing', *Oxford Review of Economic Policy,* 39(4)

operating, and environmental motivations to buy legitimately clean power. Our answer to Question 13 has indicated the wide and diverse range of such actors, many of whom would find little help from the REMA proposals, which seems to do little if anything to enhance direct consumer access to, or investment in, the emerging renewable energy economy.

All this cannot be captured just by framing “market actors” in terms of “bearing/managing risk”. This is a fundamental misunderstanding of the challenge. The absence of serious attention to consumers and first-domain decision-making in REMA is in our view a major weakness, because it neglects the potentially central – and potentially positive – role of consumers (including ‘prosumers’) in the energy transition.

- ***Active market actors and (financial) optimisation.***

Day-to-day decisions by market actors including some dimensions of investment, but particularly operational decisions dominated mainly by the self-dispatch of generators, and forward contracting typically little beyond a year ahead, so also over relatively short periods.

The current wholesale market design has proven to be a viable and potentially effective way especially of organising operating and dispatch. For investment purposes, the wholesale market contains at least two intrinsic biases against renewables investment: gas generation involves less up-front investment (thus benefiting from a major wedge between the time horizons of public interest and private profit); and their risks are self-hedged, since the wholesale market price is largely determined in relation to gas generation costs – price-setting – whilst renewables bear the price risk.[8]

The wholesale market as currently structured is thus intrinsically poorly suited to support low-carbon investment. Wind and solar generators especially are for the most part passive players, generating ‘as available’, with the willingness to invest depending significantly on government and regulatory policy made under other decision-making domains. The market is also imperfect in risk allocation and resulting pricing of operation itself, as evidenced by endemic problems in the balancing mechanism, and the levels of profits made by gas generators as well as inframarginal operations during the energy crisis.[9]

- ***Strategic decision-making.***

Actors with capacity and resources to look broadly over extended periods (in this framework, ‘third domain’ decision-making actors) and often, geographies. This is typically the domain of government decision-making, and large companies regarding infrastructure (including networks) and

[8] Grubb, M. (2022) NECC Working Paper #3 – ‘Navigating the crises in European energy: Price Inflation, Marginal Cost Pricing, and principles for electricity market redesign in an era of low-carbon transition.’ At: https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett_sustainable/files/ucl_isr_necc_wp3_with_cover_final_070922.pdf

[9] See our series *Navigating the Energy-Climate Crises,* *https://www.ucl.ac.uk/bartlett/sustainable/research-projects/2022/sep/reforming-electricity-markets-low-cost-and-low-carbon-power, particularly working papers #1 (price setting) and #2 (revenues).*

strategic decisions around technology choices, supply chain developments and large investments, maturing on multi-decadal timescales. Part of the task is for government to design markets and other signals, including risk allocations, to align such private strategic decision-making with public goals.

The success of EMR is due largely to effective government policy in this domain. The key to this was indeed the decision for the government to take on a range of risks, notably relating to price for renewables (and system security), combined with some important supporting policies. This was entirely appropriate given the combination of public objectives (decarbonisation), the endemic nature of spillovers particularly from innovation, the intrinsic bias in wholesale markets (see above) , and the fact that many dimensions of price risk are ones the private sector could neither reasonably foresee, or control – with many indeed, stemming from government decisions (e.g. carbon price, regulatory decisions including for transmission and interconnection, geopolitics etc).

For renewables, those same actors are now looking ahead and identifying that the dominant future risks will be around volume – a challenge for which CfDs were never designed and may not be appropriate, hence our responses under Challenge 2.

Note that third-domain public sector actors can in principle also include local authorities. Also, a limited number of demand-side actors, such as major energy-intensive industries, may take a strategic perspective on the risks to price and availability of energy. Such companies may seek the economic security of long-term contracts to manage price risks, but the current market (whether PPAs or wholesale) is a very poor provider for this.

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In conclusion, the challenge for the next phase of electricity transition concerns the co-evolution of low carbon generation, transmission, and more responsive demand together with both absorptive (e.g. electricity and hydrogen storage) and other flexibilities. It is not clear that REMA has yet found a balanced approach to these challenges.

Appendix: Reflections on REMA and Green Power Pool proposals

The REMA II consultation proposes rejecting a Green Power Pool approach to electricity market reform in the transition. In this Appendix we outline why we find the reasons given to be unconvincing, and touch on aspects that we believe merit further consideration, particularly given potential changes under a new government.

Basic role & rationale. First to reiterate, the purpose of a Green Power Pool (GPP) is to enable efficient feed-through of renewable electricity generation to consumers at prices which are related to the long-run (amortised investment) cost of the renewables (Table 2 of the REMA Consultation main document gives a reasonable summary of both GPP and Split Market approaches). Note that:

- This contrasts the current approach to bulk renewables, which sell into the wholesale market, through which consumers see the cost of the marginal generator (historically dominated by gas), modified by the socialised financial transfers associated with fixed-price CfDs;
- It also contrasts with the PPA market, which is disjointed between a wide variety of bilateral contracts, which as the REMA document notes is limited by three factors: *High counterparty risk; High transaction costs;* and *contract length/demand mismatches*.

A Green Power Pool can be seen correspondingly as either:

- A way to enable consumers to access bulk renewable energy on terms related to the generating costs – having already 'split the market' on the generation side through CfDs and other (necessary) mechanisms, GPP offers an extension to enable consumers (through suppliers) to access much more directly the 'pool' of renewables that are supported through long-term contracts. We set out the details of how this could work, including in relation to the variability of wind & solar, in our paper detailing GPP principles.[10]
- A GPP can also be seen as a way of addressing the three limitations to PPAs, by government playing a role in helping to standardise and aggregate ("pool") contracts between renewable generators and consumers (via suppliers). Thus for example, corporate consumers, or suppliers wanting to market renewable electricity with more credible mechanisms than current 'green certificates', would gain much more efficient access to renewable generation compared to current arrangements.

[10] Grubb M., P.Drummond, S.Maximov (2022), Separating electricity from gas prices through Green Power Pools: Design options and evolution. *Navigating the Energy-Climate Crises,* Working Paper #4, available at https://www.ucl.ac.uk/bartlett/sustainable/research-projects/2022/sep/reforming-electricity-markets-low-cost-and-low-carbon-power

REMA II proposals do nothing to resolve the growing disjuncture in the existing system. Notably, the tension between the cost of renewables generation (known and stable at point of contracting) and the price of electricity to consumers (uncertain and volatile over extended periods). Nor do the REMA proposals do anything to facilitate efficient direct consumer access to bulk renewable energy.

We noted in our response to first REMA consultation, "REMA Chapter 4 does not quite pinpoint the structural disjuncture" between the supports for clean generation through undifferentiated long-term contracts, and the short-term and gas-driven basis of the wholesale market as the channel to consumers. Pointing to the declining role of gas does not automatically translate to a market structure reflecting the characteristics of a renewables-dominated system.

The REMA II proposals to continue with CfDs and Capacity Market do nothing to resolve this disjuncture: on the contrary, its implication is that the system will become increasingly disjointed, with the majority of generation coming from sources whose overall costs have almost nothing to do with the cost realised in the wholesale market or value relating to consumers.

Objections. The REMA II consultation acknowledges that a Green Power Pool would be feasible, but says it "failed Deliverability and Investor Confidence criteria".

We are unclear how an arrangement which is primarily about the way that renewable electricity is made available to consumers fails an "Investor Confidence" criteria, since it could be based upon the output from renewables supported under the existing mechanisms (e.g. CfDs) or proposed additional (e.g. Labour proposals for GB Energy) mechanisms.

The concern about Deliverability was understandable, particularly if compared with a continuation of current mechanisms. However, our submission has underlined why such a continuation – based on current instrument designs - is likely to be ineffective, as renewables start to dominate the system.

Moreover, the Labour proposal for GB Energy suggests that new institutional arrangements will be introduced, which (along with the creation of NESO) could help to Deliver the structural transition required to market arrangements which better reflect the realities of a renewables-dominated system.

The final objection raised in REMA is that electricity marketed through a GPP arrangement could be sold-on / arbitraged, so that ultimately it would make no difference. We disagree. This appears to adopt a classical 'representative agent' approach of assuming essentially identikit consumers, and suppliers, with identical '*homo economist*' characteristics. It takes no account of the reality of both companies and individuals with varied preferences, motivations, and capabilities.

Thus some – perhaps many – consumers, both corporate and others, may be interested in striking long-term contracts to buy electricity based genuinely on renewables - whether for environmental / CSR reasons, or simply for the benefits of price predictability. The same could go for supply companies, subject to Ofgem's tests on financial resilience, enabling them to avoid many of the inefficiencies of the current system in regarding to renewables-based purchases. The REMA II consultation, to our mind, offers no convincing reasons to avoid market reforms which would facilitate this.[11]

There would of course be several options in detailed design, and also we note potentially interesting interactions with locational issues. Should the REMA process move towards zonal pricing, for example, options for GPP design could first be developed and tested in a regional context, which would also enable consumers in a region to benefit from accepting the construction of cheap renewables and enhancements to distribution networks in their region.

Hence, we are far from convinced by the REMA II proposal to exclude Green Power Pool options from further consideration.

[11] Indeed, even in purely economic terms many economists have pointed to the dominance of very short-term purchase and inadequacies of long-term contracts in the GB Wholesale market as a problem. A GPP could provide an institutional structure to encourage efficient long-term contracting on the consumer side, also facilitating the involvement of long-term financial players like insurance and pension funds beyond purely generation and transmission assets.