REMA Consultation 2
REA Townhall

Friday 5th April 2024

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  - Competitively sensitive information covers any non-public strategic information about a business's commercial policy. It includes, but is not limited to, future pricing and output plans

  - Please note this session is being recorded for note taking purposes.

Agenda

1) REMA in Context – The process so far (10 min)
2) Reviewing the four challenges

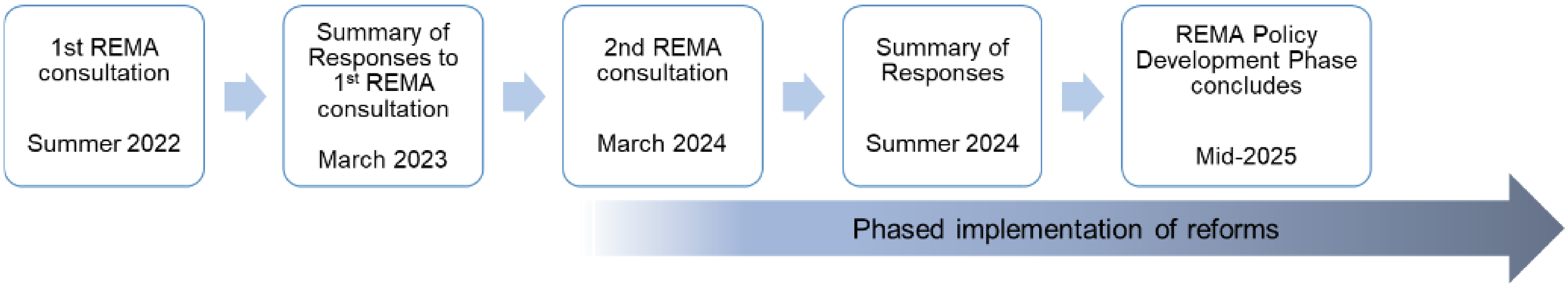
I. Passing through the Value of a renewables-based system to consumers (10 min)
II. Investing to create a renewables-based system at pace (30 min)
III. Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system (20 min)
IV. Operating and Optimising a renewables-based system, cost effectively (30 min)

3) Compatibility and Legacy Arrangements (15 min)

4) Next Steps (5 Min)

The Process

Figure 1: REMA Milestones



The REA Responding to the First REMA Consultation

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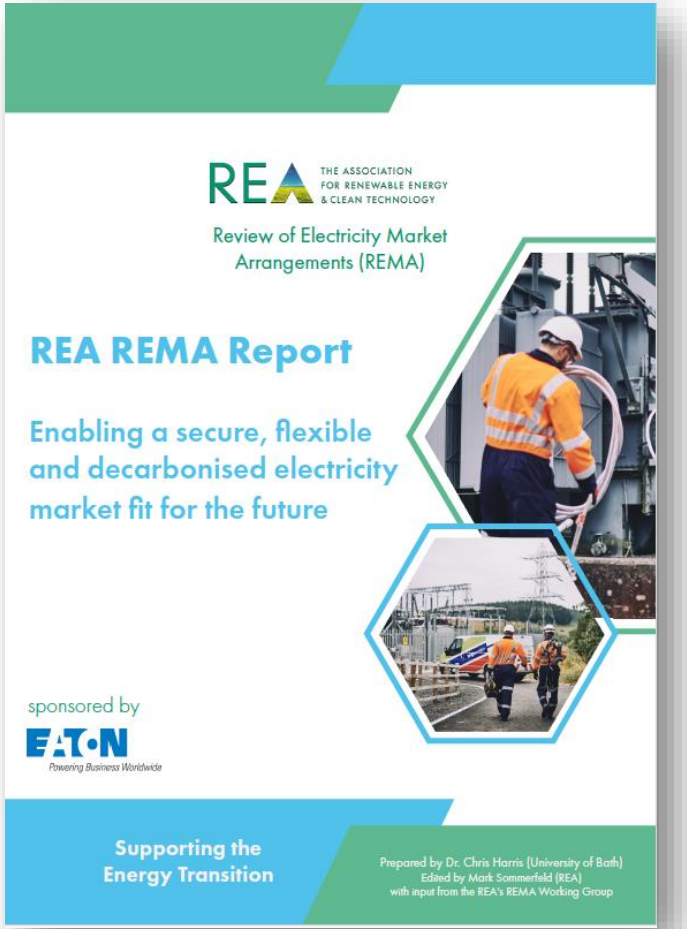
- Established the REA Members Task and Finish REMA Working Group to help develop views.
- Ran several member engagement events over 2023, both in advance of the first call for evidence and during the developmnet of our REMA report.
- Submitted detailed response to the first consultation
- Published the REA REMA Report, June 2023
- Continue to engage in parallel consultations that impacts REMA. (CfD, Capacity Market, Innovation Models)
- Sit on the Governments REMA Market Participants Forum

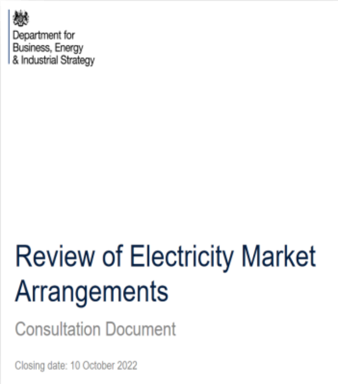


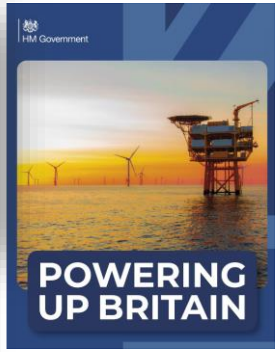
REA Task and Finish REMA Working Group:

Isabel Boira-Segarra	**Future Earth Energy**
Jon Crouch	**Infinis**
Peter Dickson	**Glennmont Partnerns by Nuveen**
Kit Dixon	**Good Energy**
Keith Gains	**Quinbrook Infrastructure Partners**
Stephen Hill	**Eversheds Sutherland**
Mark Howitt	**Storelectric**
Richard Molloy	**EATON**
Marcus Newborough	**ITM Power**
Kamila Nugumanova	**Drax**
Dai Richards	**Hitachi Energy**
Jonathan Scurlock	**NFU**
Christie Sims	**BSR**
Jerry Stokes,	**Gridserve**
Hilary Stone	**Imperial College**
Gregory Triantafyllidis	**JBM Solar**
Duncan Valentine	**Almax Partners**
Frances Warburton	**EY**
Darren Williams	**ECO2**

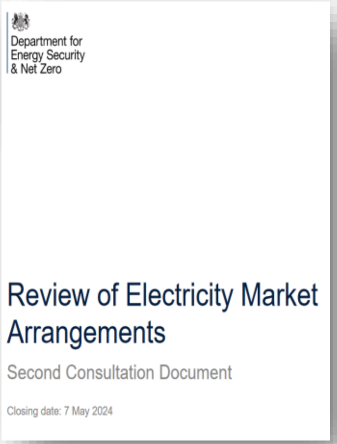
REMA in the context of the energy crisis

Industry recognise that the impetuous and urgency of REMA has changes since it was first announced.





March 2024



April 2022 — **July 2022** — **Sep 2022** — **March 2023** — **August 2023**

Russia Invades Ukraine – Feb 22

Rising Energy Prices

Stabilising Energy Market (But still at historically high prices)

Urgent Action needed to address energy crisis, security of supply and rising bills

Energy Bill Support and Introduction of Electricity Generator Levy

Ongoing need to design a market fit for fully decarbonised power system by 2035

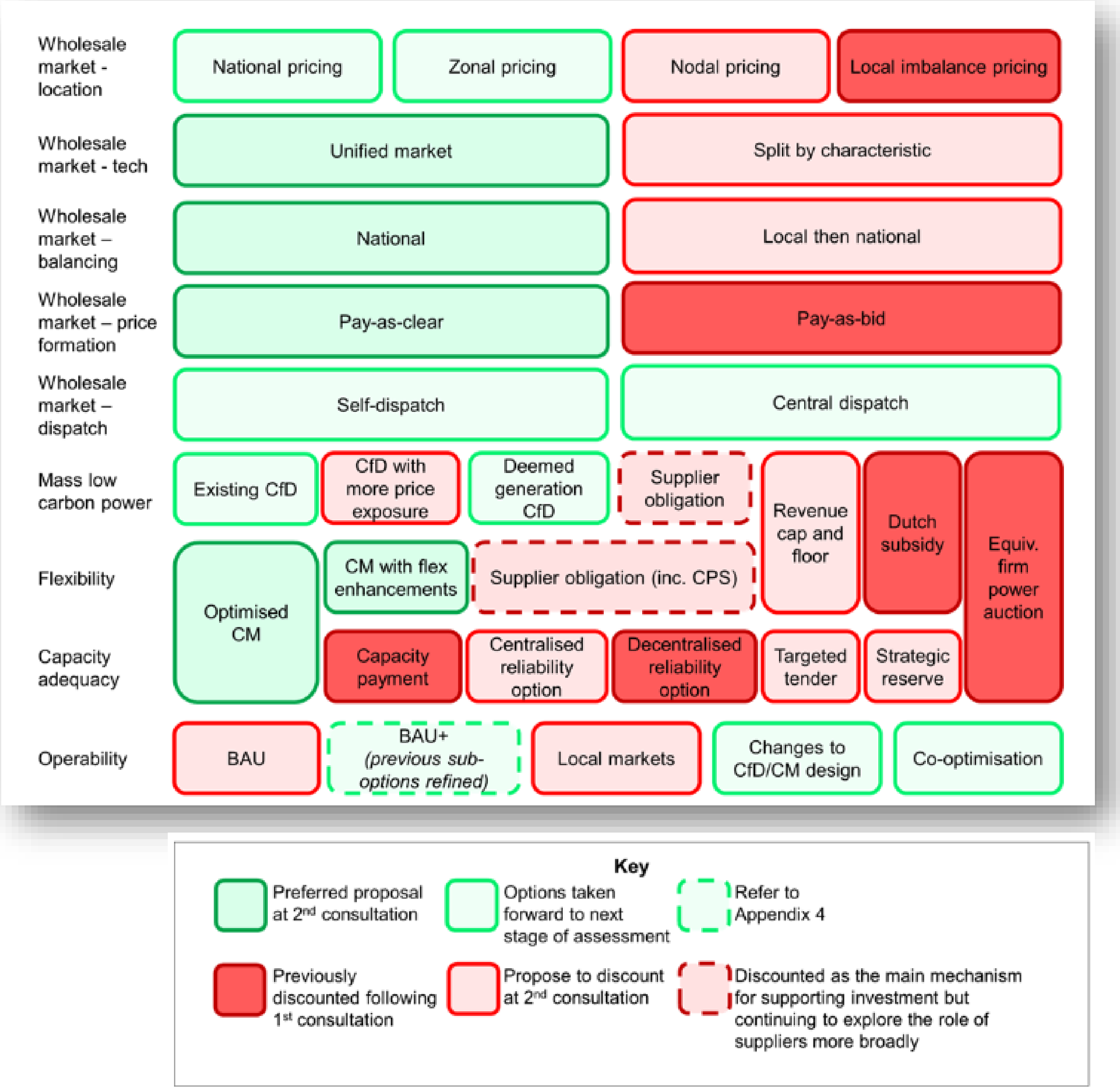
REMA Consultation 2 Summary

REA Intial View

- Intial Stage reflects many of REA's recommendations.
- We are pleased to see more disruptive proposals rejected.
- Remains a lot to be considered in terms of CfD design, in particular supporting firmness and flexibility.
- Disappointed by focus on new gas generation in Government press statement.

DESNZ Objectives on REMA 2:

1) Set clear Direction
2) Address four Key Challenges
3) Get Stakeholder views on remaining short-list of options
4) Examine impact on Legacy Arrangements and Assets



Four Key Challenges of REMA Consultation 2

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

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

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

Challenge 4: Operating and optimising a renewables-based system, cost-effectively

Challenge 1: Passing Through The Value of a Renewable Based System

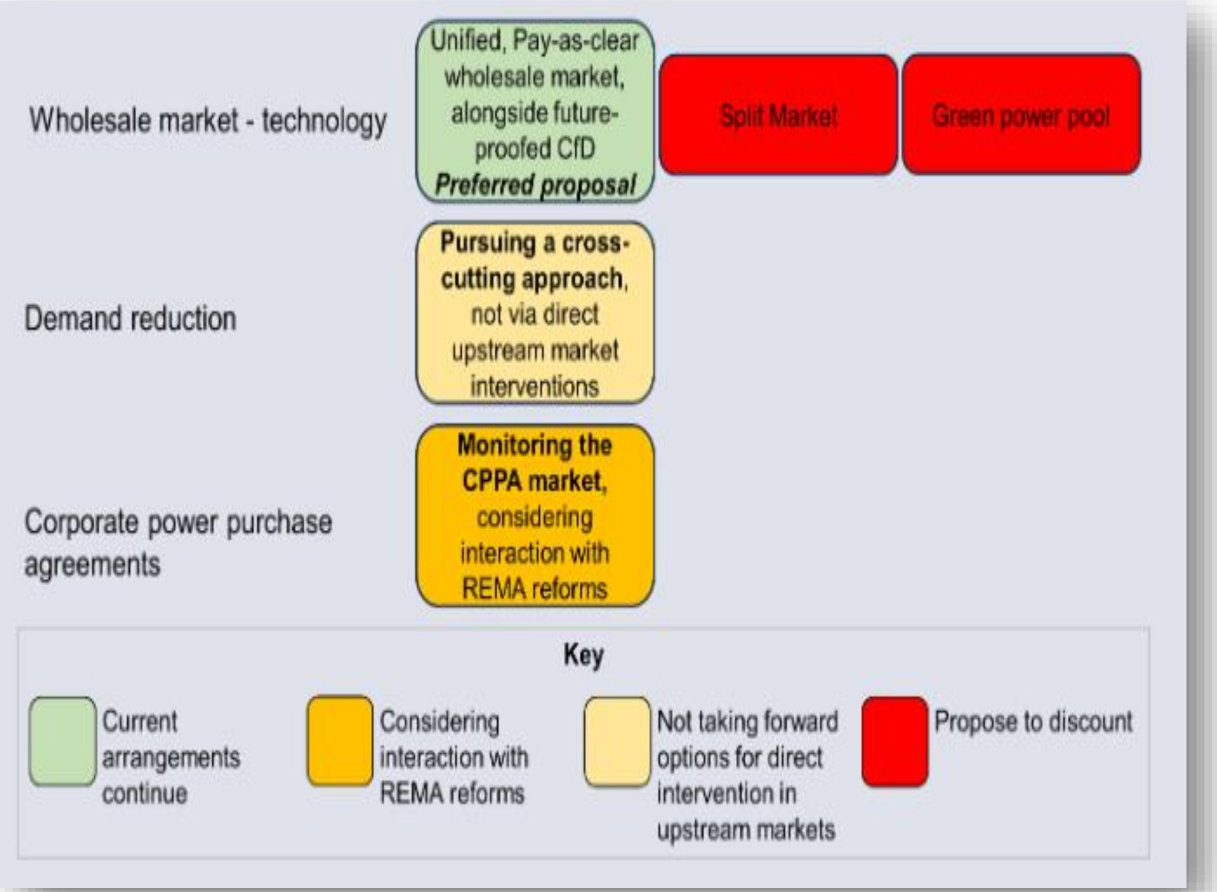
Government want to continue to look at how to decouple cost of electricity from short run marginal costs.

However, they have dismissed more radical approaches such as the Green Power Pool or Split Market.

Instead, they want to **future-proof the CfD**. (Options in Challenge 2). This protects consumers during periods of high wholesale prices, for an increasing proportion of generation.

Government also recognise role of **Corporate Power Purchase Agreements** as a way outside of the CfD Market to mitigate risks. They are interested in how this role could grow.

They are also interested in how a **cross cutting approach could deliver demand reduction**, but not direct intervention due to market complexity.



C1: Corporate Power Purchase Agreements

Gov. believe there is significant room for growth of the CPPA market. However, identify barriers:

- High Counterparty Risk
- High Transaction costs
- Contract Length/Demand Mismatches

Potential Actions:

Standardised Contracts	*Exempt CPPA holders from CfD costs*	*A Contracts Register*	*Preference to CPPA holders in CfD Auctions*

"However, we believe at this time these are likely to be unworkable, or high risk, or low impact, or address issues the market is already starting to resolve itself. Therefore...we do not believe there is need for government intervention."

<u>Questions:</u>

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?**

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

C1: Demand Reduction

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Government have decided to focus on downstream energy efficiency polices. Rather than build demand reduction into REMA. They emphasise several existing schemes.

Better valuing whole system benefits of demand reduction by reviewing appraisal methodologies to capture whole system benefits of DR.

Sharper price signal through zonal pricing (c4) and Ofgem move to half hourly settlement

Retail Market Review

Policies for Energy efficiencies in Homes – GBIS, BUS, SHDF, HUG

Policies for Energy efficiencies in Businesses– IETF, Extension of CCA Scheme

Questions:

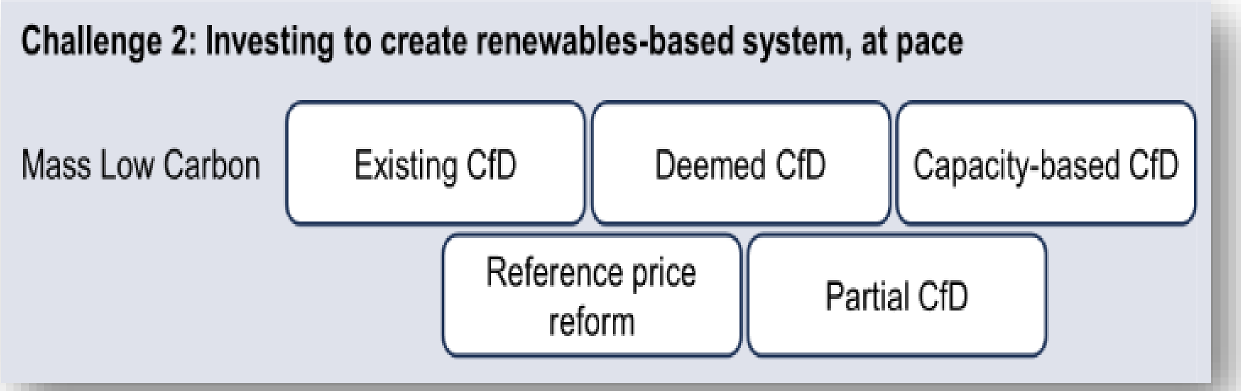
3) Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction? Please provide supporting reasoning, including any potential alternative approaches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

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

Government see evolution of the CfD as the best way to decouple marginal price and deliver renewables. However, recognition of growing issues with existing CfD:

- Need to grow renewable capacity faster
- Doesn't address Volume Risk
- Maximises power production, regardless of system need.
- 'Herding' leads to cliff edges and negative pricing
- CfD Impacts price formation
- Doesn't reward ancillary services or flexibility
- Disincentivise forward trading

"The CfD reform options offer different ways of providing revenue certainty (to support investor confidence and keep the cost of capital low) and controlling the degree of exposure to both price and volume risk (to maximise CfD assets' responsiveness to system needs)."



<u>Questions:</u>

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

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?

C2: Deemed CfD

Use existing structure of the CfD but payments would be determined by how much generation assets could have produced each hour, rather than metered data.

This would:
- Allow generators to respond to other markets signals.
- Still protect assets from price risk
- Reduce volume risk
- Potential to remove negative pricing rule
- Allocate risk differently

However, would also:
- Create profile risk – if deemed is not aligned to actual generation.
- Gaming and overcompensation risk
- Not be responsive to locational pricing unless further complex design considered.

Deeming Methodology options:
O1: Third party combines weather and asset data to calculate output. Robust but could be costly for generators.
O2: Asset owners input data into a government-set methodology for output calculation. Cheaper but may not be robust.
O3: Govt.-appointed generators determine output. Less manipulation risk but less accurate for individual assets.
O4: Subsidy payments would be based on metered output except when assets participate in specific services, (ESO Data) allowing assets to earn extra revenue from ancillary services. Less disruption but only tackles one distortion.

A Capacity Payment would pay an asset, once operational, a regular, fixed amount based on installed renewable capacity (£/MW), independent of the asset's market activity.

- Generators would therefore operate on merchant terms, optimising their trading and operational strategies to maximise revenues across markets.

- When bidding for a capacity-based CfD in competitive auctions, generators would need to reflect anticipated market revenues in the level of capacity payment sought.

- The mechanises could be combined with a 'availability factor' , effectively like the capacity market.

This would:
- Expose generators to both volume and price risk day-to-day, but still provide some revenue certainty.
- Reduce complexity.
- Could allow locational pricing signals
- Allocate risk differently

However, would also:
- Need a consumer protection mechanism to shield consumers from high wholesale costs. (gain share mechanism)
- Increase revenue risk to assets, which may mean high-capacity payments to cover cost of capital

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)?

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.

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.

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?

10. Do you have a preference for either the deemed CfD or the capacity-based CfD model? Please consider any particular merits or risks of both models.

C2: Further Options Reference Price Reform and Partial CfD

Supplementary reforms to address some of the **operational** and **investment distortions** associated with the current design, without changing the payment structure. These could be implemented in parallel with, or instead of, payment structure reforms.

Partial CfD payments: asset is split into two

- Only a % of an asset's total capacity would be covered by a CfD for all new projects
- Only this portion would be subject to top-up/claw-back payments from the LCCC equalling the difference between the strike price and the reference price
- Other portion would operate on a merchant basis
- + Could improve dispatch efficiency and reduce herding, maintains merchant portion of the market and reduces disincentive against ancillary services
- — Strike price increases proportionally: no benefit vs. BaU, negatively impacts costs of capital + investor confidence, and potential gaming

Reference price reform : forward market price, not daily

- Hybrid: portion set using a longer reference price whilst remaining portion set at the day-ahead price. The key element is the % split between the day-ahead market and other markets
- Extended: calculated in a similar way to the existing reference price but using a weighted volume average of more market price data, up to one month prior to delivery
- + Greater forward market liquidity and reduced herding
- — May disadvantage smaller assets as may not be able to participate in forward trades (Hybrid), and uncertainties around effectiveness (Extended)

C2: CfD Questions

11. Do you see any particular merits or risks with a partial payment CfD?

12. Do you see any particular merits or risks with the reforms to the CfD reference price we have outlined? Please consider how far the two reforms we have outlined might affect both liquidity in forward markets and basis risk for developers.

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?

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

Recognised that current market does not maximise the potential for the full range of flexible technologies to deploy or operate flexibly..

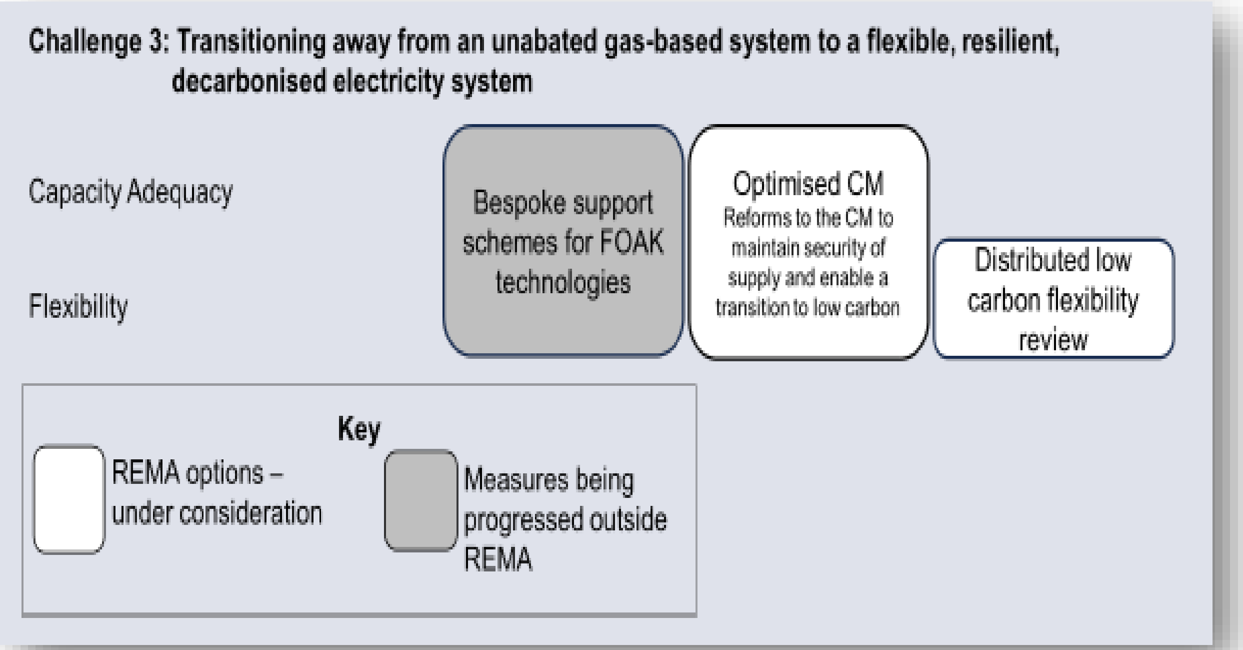
Govt. have decided to retain the Capacity Market (CM) but to optimise it.

Previously they considered:

- Split Auction
- Single auction with multipliers
- **Single auction with multiple clearing prices (minima)**

Further reforms also possible like auction targets, reliability standard or emission limits.

Accompanied by bespoke support for strategic technologies like LDES, H2P and CCS.



Single auction with multiple clearing prices (using minima) - where all technologies continue to compete in the same auction, but a mechanism is introduced to allow different clearing prices to be determined for desirable characteristics. Modelling explored how this could be achieved by setting a minimum procurement target (otherwise known as minima) for desirable characteristics.

This would have
- Administrative simplicity in having one auction
- Flexibility over how the minima is set and how it affects the overall auction parameters and design

However,
- Require further work to understand how minima could be defined and set.

Further Auction considerations

Auction Targets

Strengthen CM rules around market power

Refining the Reliability Standard

Lower Emission Limits

Consider further changes (contract length?)

C3: CM Questions

14. Are there any unintended consequences that we should consider regarding the optimal use of minima in the Capacity Market (CM) and/or the desirable characteristics it should be set to procure?

15. What aspects of the wider Capacity Market (CM) framework, auction design and parameters should we consider reviewing to ensure there are no barriers to success for introducing minima into the CM?

16. Do you agree with the proposal that new lower emissions limits for new build and refurbishing Capacity Market Units (CMUs) on long-term contracts should be implemented from the 2026 auctions at the earliest?

17. If you are considering investment in flexible capacity, to what extent would emissions limits for new build and refurbishing capacity impact your investment decisions?

Challenge 3: Delivering flexibility needed (inc. role of Gas and Bespoke Support)

The consultation explains that **30-50GW of long duration flexibility** may be required for the electricity system by 2035 to provide stability and security of supply. They plan to deliver this through a **mix of different solutions**

One of these solutions put forward by Govt. is building **new gas power plants** as a large proportion of them will be coming towards the end of their lifetime by 2035. They state that **25-27GW of unabated gas** is required for 2035 as heat and transport continue to electrify and that without it the power system would have increased costs and delivery risks associated with it. REA will be challenging this assumption.

Other solutions for delivering long duration flexibility are bespoke support mechanisms for:

- **Hydrogen to Power**
- **Power generation with CCUS**
- **Long Duration Energy Storage**

These technologies will provide low carbon long duration flexibility for 2035 and beyond, and past the need for **gas power plants which will have decarbonisation pathways** implemented on them

Ch3: Delivering flexibility needed Questions

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?

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.

20. Do you agree that an Optimised CM and the work set out in Appendix 3 will sufficiently incentivise the deployment and utilisation of distributed low carbon flexibility? If not, please set out what further measures would be needed.

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.

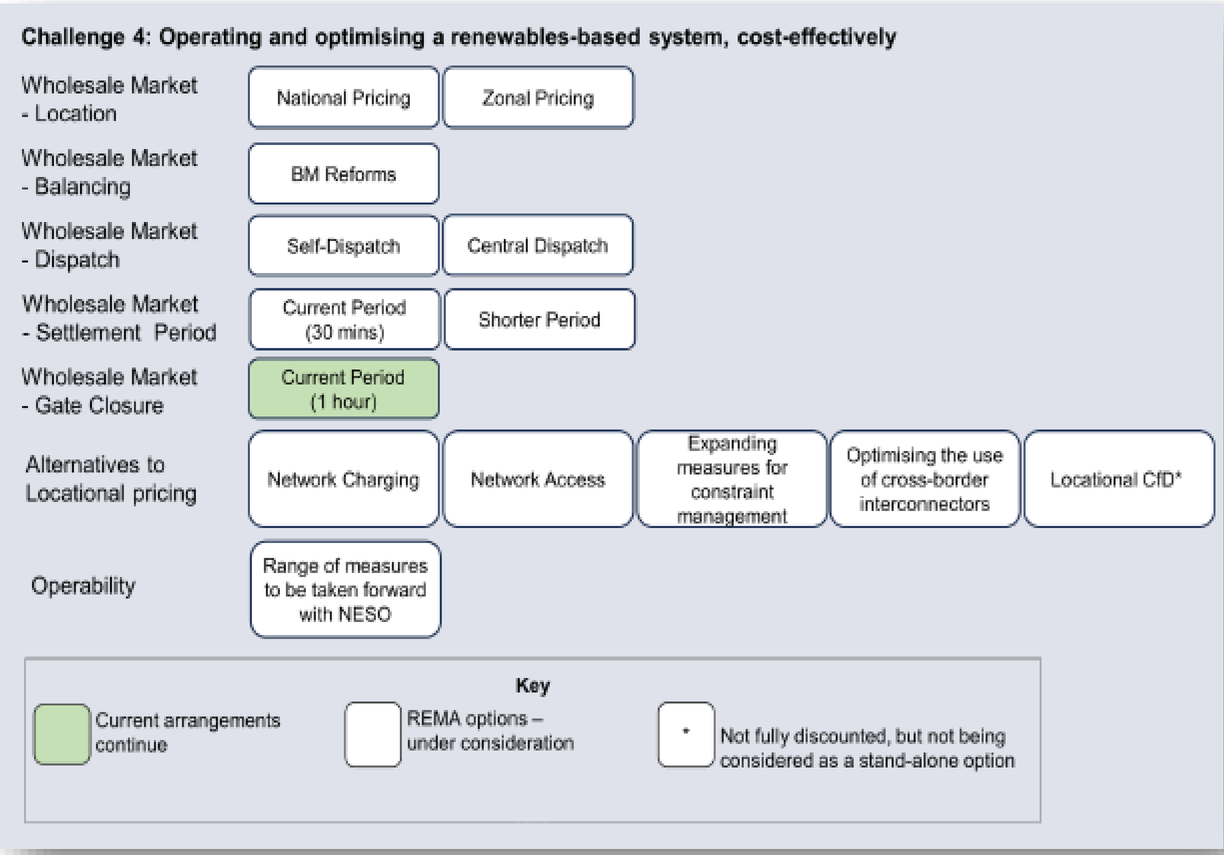
Challenge 4: Operating and Optimising a renewables-based system, cost effectively

Govt. still keen to introduce some form of locational pricing, however, have discounted nodal pricing given impact on investor confidence.

Focus will be on modelling zonal vs national pricing for further consideration.

Alternatives to locational pricing also be considered alongside proposals.

Temporal signals could also be impacted by improving balancing and Ancillary services. ESO leading work on Dispatch and scheduling arrangements.



Challenge 4: Dispatch, Sequencing, Settlement Periods

Update provided by
Francisco Andrade and Ed Farley
National Grid ESO

Challenge 4: National Vs Zonal Pricing

Why change seen as necessary
Generation increasingly locating further from demand
Constraint costs risen significantly- £0.7bn 2018/19 to £1.8bn in 2022/2023
'Fragmented' incentives across planning and energy system, for optimal siting of generation resources.

<u>Had considered two sets of market-based options for sending more efficient locational signals:</u>

• *Locational pricing options*: Nodal and zonal pricing. Send both locational investment and locational operational signals through the wholesale market.
• *Alternatives to locational pricing options*: eg transmission network charging & access reform

Government preference is for Zonal Locational Pricing – this is in line with REA's view

Initial indications of how Zonal Locational Pricing could work – to be fully developed in 'next stage'
CfD sites receive new reference prices for the locational zone – but no change to Strike Prices
Consumers may be exposed to the variability in prices (TBC) but still expected to benefit on a net basis
Self dispatch initially (possible stepping stone to central dispatch)
Approximate 5 years implementation timeframe

Challenge 4: Alternatives to Locational Pricing

These are primarily designed to send a locational investment signal, outside of the wholesale market. Government indicate most options could be implemented alongside Zonal Pricing.

Alternative options DESNZ are considering within REMA are:

• Using Ofgem's pre-existing network charging reform programme (option A)

TNuOS: Review already underway, may sharpen existing zonal differences (27 generation zones), may result in changes to the 'Permitted Range (£0-2.50/MWh for generators). DUoS: early stage review by Ofgem.

• Reviewing Ofgem's transmission network access arrangements (option B)

Ofgem still reviewing and no clear options given, but 'firm' connections discussed and changes for new/existing (only if Zonal Pricing / Central dispatch adopted), generators

• Expanding measures for constraint management (option C)

Options include: Expanded local constraints markets; Improved forecasting of congestion; Storage-based solutions; Before day-ahead constraint price signal designed to discourage generation in areas behind constraints at times of congestion (early stages)

• Optimising the use of cross-border interconnectors (option D)

The ESO already improving the efficiency of existing interconnector redispatch and SO-to-SO trading processes. Also involves assessing options to enable the exchange of balancing products between the EU and UK.

- Also examining Temporal signals

Providing shorter Settlement periods (5-15 mins) and Gate Closure (c.30 mins)

Adding locational signals to the CfD or Capacity Market schemes has been ruled out.

C4: Locational Pricing Questions

22. Do you agree with the key design choices we have identified in the consultation and in Appendix 4 for zonal pricing? Please detail any missing design considerations.

23. How far would our retained alternatives to locational pricing options go towards resolving the challenges we have identified, compared with locational pricing? Please provide supporting evidence and consider how these alternative options could work together, and/or alongside other options for improving temporal signals and balancing and ancillary services.

24. Do you agree with our proposed steps for ensuring continued system operability as the electricity system decarbonises? Please detail any alternative measures we should consider and any evidence on likely impacts.

Legacy Arrangements

Govt. Recognise that REMA reforms could impact legacy arrangements and assets in terms of:

- **Functional effects**: impacts on contracts and schemes
- **Financial effects**: impacting asset revenue, price volume and level of risk.

Approach:

- Scheme-by-scheme basis analysis in next phase.
- This include schemes currently in development that may allocate contracts prior to REMA decision

Managing Impact on existing CfD:

- If locational pricing is introduced, existing CfD (inc AR 6) would shift from national reference price to a zonal refence price, still being topped up to the strike price. This would insulate CfD assets from locational price risk.
- Impact on RO sites still being considered, alongside repowering proposals (as seen in AR 7 consultation).

Existing Schemes to Be considered	
Contracts for Difference	Capacity Market
Renewable Obligation	Feed in Tariff
Net Zero Hydrogen Fund	Interconnector Cap and floor
Nuclear CfD and RAB	
Future Schemes to be considered	
Offshore wind hybrid assets	Hydrogen business models
Power BECCS/GGR	Dispatchable Power Agreement
Long Duration Energy Storage	

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

27. Do you agree with our approach to assessing the impact of REMA reforms on Legacy Arrangements?

28. What risks do we need to consider with regard to Legacy Arrangements, and how can they best be mitigated?

Next Steps

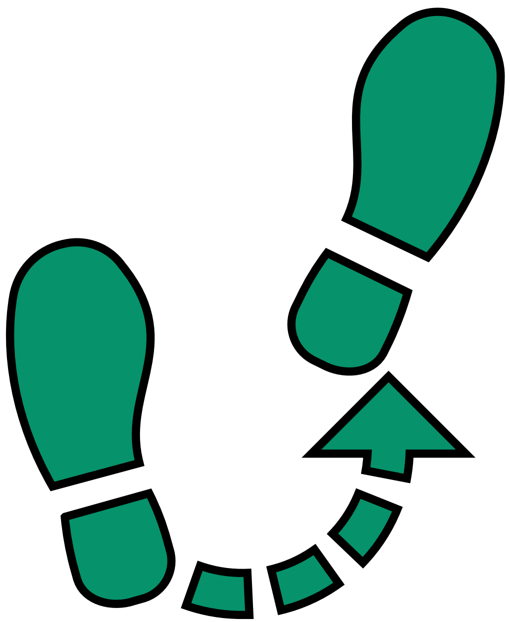
- Any further intial feedback on REMA proposals should be sent to the policy@r-e-a.net by the 19th April.

- REA will look to circulate a draft response by the end of April to all members. As such, there will be opportunity to provide further input on our response.

- REA will consider if further member meetings are required ahead of consultation deadline on the 7th May.

- REA and its members are also getting involved in Government REMA working groups. This recently included Future Renewables Investment Expert Panel.

- REA will continue to engage with the DESNZ REMA team following the completion of the consultation to inform next steps.



REA Policy Team

Samuel Adekanle
Policy Analyst, Grid & Networks
sadekanle@r-e-a.net

Francesca Cullaney
Policy Analyst, Power & Flexibility with Green Finance
fcullaney@r-e-a.net

Frank Gordon
Director of Policy
fgordon@r-e-a.net

Mark Sommerfeld
Deputy Director of Policy
msommerfeld@r-e-a.net