



Department for  
Energy Security  
& Net Zero

# Review of Electricity Market Arrangements

Autumn Update

December 2024



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# Executive Summary

The purpose of this publication is to provide an update on policy development within the Review of Electricity Market Arrangements (REMA) Programme and how our vision for electricity market reform sits alongside the Clean Power 2030 Action Plan.

The message that has emerged loud and clear from the feedback gathered during the second REMA consultation (published in March 2024), as well as from ongoing discussions with stakeholders, is undeniable. Electricity markets have a central role in delivering value for consumers. Reform is urgently needed to ensure our market arrangements are fit for the 2030s and beyond. There is a pressing need for greater clarity on the status of the different longer-term options for market reform. Therefore, this publication:

- Provides an update on REMA options development and assessment, with a particular focus on providing further clarity for investors and wider stakeholders on wholesale market reform. No decision has yet been taken between zonal pricing or reformed national pricing, and both options remain under equal consideration. However, significant progress has been made to narrow down the range of potential options, as well as to define what either reform might look like if implemented;
- Reaffirms our ambition to conclude the policy development phase of the REMA programme by around mid-2025 and confirms that the timetable for REMA decisions will align with the timetable for the next allocation round (AR7) for the Contracts for Difference (CfD) scheme; and
- Confirms our commitment to treat agreements under the next CfD allocation round (AR7) in the same way as existing CfD agreements in relation to any legacy or transitional arrangements. We expect existing, and AR7, CfD contracts to be insulated from zonal price risk (should zonal pricing be adopted in future). Transitional and legacy arrangements are being considered under both potential market designs.

We are continuing to assess whether zonal pricing or reformed national pricing would be the best approach for the future GB electricity system and will publish a Cost-Benefit Analysis alongside our final decisions. We are exploring how to design and implement either option in a way which reduces transitional uncertainty for investors while still addressing the challenges our power system will face in future and delivering value for consumers. This publication outlines our initial thinking on the key elements of either approach – the areas where we expect early clarity for investors and market participants is of greatest value. We are committed to engaging stakeholders further on these questions ahead of final REMA decisions.

This update is published alongside the Clean Power 2030 Action Plan and the Summary of Consultation Responses to the second REMA consultation.<sup>1</sup> The Clean Power 2030 Action Plan is the roadmap to achieving a clean power system by 2030. It focusses on accelerating the deployment of renewable energy, investing in innovative flexible technologies, and reforming the broad landscape of enabling policy and legislation that will support this transition. Among a range of critical actions, the plan also sets out the important role of the CfD and

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<sup>1</sup> <https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements-rema-second-consultation>

Capacity Market (CM) schemes and the immediate actions we can take through them to help deliver Clean Power 2030. This publication provides an update on our evolving thinking regarding longer-term reforms to both schemes and the role they must play beyond 2030.

# Introduction

We are undergoing a significant transformation in our electricity system, with renewables taking centre stage in the transition to a clean power system. Our market arrangements – the wholesale market and balancing arrangements, and the government support schemes that impact them – form the backbone of this system. They guide efficient operational and investment decisions so that the system is cost-effective and delivers value for consumers.

Today the Government has set out its plans to provide Great Britain with cheaper and clean power by 2030.<sup>2</sup> Review of Electricity Market Arrangements (REMA) will deliver the reformed market arrangements in which most existing and Clean Power 2030 projects will operate. Therefore, it is crucial that our market arrangements evolve to be fit for purpose for clean power in 2030 and beyond. In the Clean Power 2030 Action Plan, published alongside this document, we outline the shorter-term market reforms which will help the Government to meet its world-leading clean power targets. In this publication, we set out progress since March 2024 when we published the second REMA consultation on the options for longer-term electricity market reform being considered, as well as the next steps for decision making.

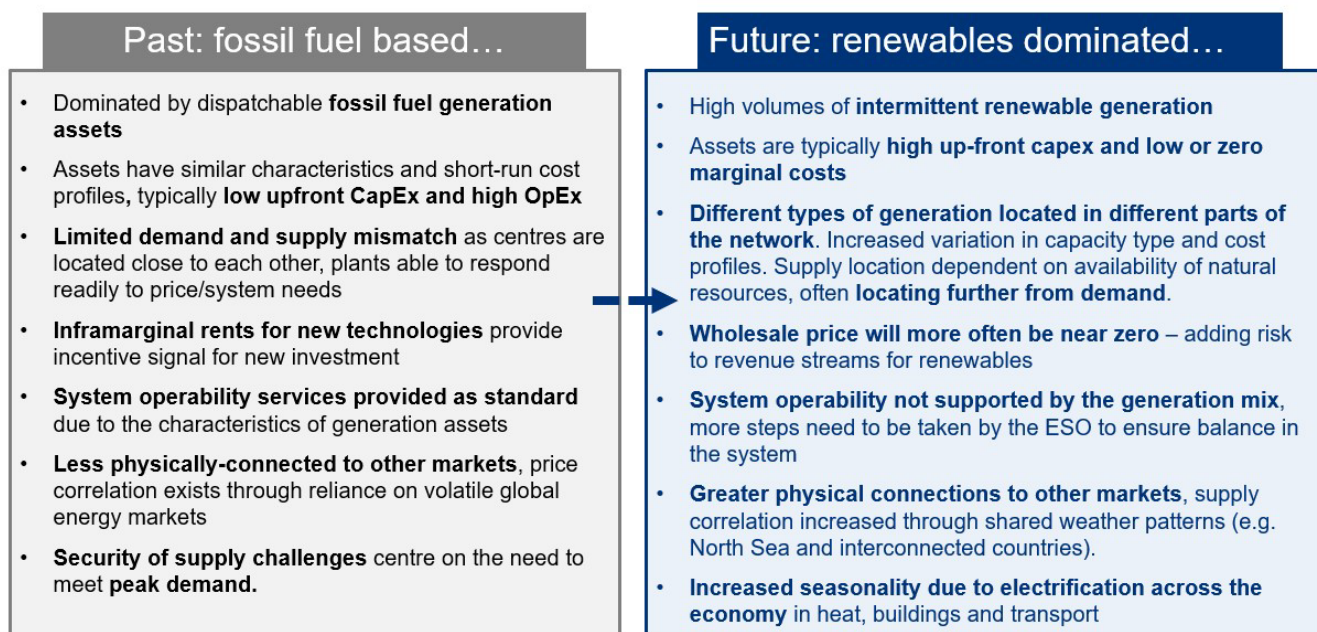
We need to secure billions in investment for new generating capacity while keeping ongoing operational costs low, and the electricity system secure. The stakes are high, and long-term reform through REMA is the solution to ensure that the clean power transition is a sustainable one which continues to deliver value for consumers. If our electricity market arrangements send the right signals, and work in tandem with other initiatives such as the Clean Power 2030 Action Plan and the Strategic Spatial Energy Plan (SSEP), we can unleash a wave of clean power that will transform our future swiftly and cost-effectively.

## Background

A renewables-dominated electricity system will have different characteristics from the fossil fuel-based generation system we have previously designed our markets around. The differences between the two systems are summarised in the table below.

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<sup>2</sup> <https://www.gov.uk/government/publications/clean-power-2030-action-plan>



These characteristics of a renewables-based system mean several issues need to be addressed:

**Wholesale electricity markets face growing challenges.** Renewables are locating further from demand and are not incentivised to provide the same suite of operability services needed to run the system securely. This is causing strain on balancing the system, and current wholesale markets are leading to operational inefficiencies. For example, flexible assets can sometimes exacerbate network constraints due to a lack of locational operational signals. System operability will also become more challenging as the system decarbonises and more intermittent sources of generation change the characteristics of the network.

**Renewables must continue to form the backbone of generation supply.** To meet future demand, annual capacity deployment rates will need to double from the mid-2020s. Scaling up low-cost renewable electricity through the CfD scheme will be critical for meeting demand. With a higher proportion of variable renewable generation on the system, we expect an increase in the number of periods when electricity prices are very low or negative. This will provide opportunities for innovation and for domestic and non-domestic consumers to benefit from cheaper electricity. However, we must also ensure that generators can obtain sufficient revenue to maintain investor confidence in GB renewables.

**The nature of our security of supply challenges will change.** We will need to manage periods when renewable generation is lower, as well as meeting the hours of peak demand. The rollout of short-duration flexibility – such as heat pumps, electric vehicles, and batteries – will help consumers save money and keep system costs as low as possible. Long-duration flexible technologies will complement these and will be critical in enabling the safe transition from unabated gas to low-carbon alternatives. Market frameworks will need to evolve to manage this transition, ensuring that Great Britain has an appropriate level and mix of flexible capacity to meet demand and face changing risks as cost-effectively as possible.



Addressing these challenges is at the heart of REMA. The policies being considered, through reforms to all electricity (non-retail) markets, the CfD scheme, and the CM will:

- Sustain the scale and pace of investment needed for future deployment of renewables and other forms of low-carbon generation;
- Ensure a smooth transition away from an unabated gas-based system to a flexible, resilient, clean electricity system; and
- Optimise the siting of assets and operation of a renewables-based system so that it is cost-effective.

## Progress to Date

REMA was first announced in April 2022. A first public consultation launched in July 2022 which set out the case for change. A second consultation followed in March 2024, to which a summary of responses has been published alongside this document. In this Autumn Update, we have significantly narrowed down reform options, including in response to feedback from our consultations following the second consultation.

**REMA remains a top priority for the Government.** Markets will play a critical role in sustaining our transition to a clean electricity system and in delivering value for consumers. Through well-structured markets, efficient price signals can be sent to help ensure assets are deployed at least cost, are built in more efficient locations for the system, and that they operate at more optimal times and in more optimal ways. These signals can reveal the value of flexibility, maximise asset responsiveness, and enable consumers to feel the full benefits of a clean power system with lower costs and greater control of their energy. This will encourage competition and innovation and enable consumers to keep their bills as low as possible.

REMA's second consultation in March 2024 identified four key challenges facing future electricity markets:

**Challenge 1:** *Passing through the value of a renewables-based system to consumers.* We decided to maintain a wholesale market based on short-run marginal pricing and use a future-proofed CfD scheme to accelerate renewables deployment. We rejected options to split the electricity market by technology via a Split Market or Green Power Pool. Instead, we emphasised the role of the CfD scheme and Corporate Power Purchase Agreements (CPPAs) in promoting renewables within existing market structures. The increased rollout of renewables as part of 2030 Clean Power will provide even greater insulation for consumers from volatile global gas prices.

**Challenge 2:** *Investing to create a renewables-based system at pace.* We committed to continuing a CfD-type scheme to maintain renewable generation investment while ensuring value for consumers. However, we recognised the need for it to adapt to the challenges of a future clean power system. We outlined potential reforms to the CfD payment structure by delinking payments from output through either deemed payments or a capacity payment

model. Additionally, we described potential supplementary reform options to increase exposure to market signals, including a partial CfD and reference price reform.

**Challenge 3:** *Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system.* We committed to retaining the CM as our primary capacity adequacy mechanism and reviewed options to evolve it to meet future challenges. We sought views on introducing a minimum procurement target ('minima') into the CM, calling it an 'Optimised CM,' as an enduring mechanism to support investment and deployment of low-carbon flexible technologies.

**Challenge 4:** *Operating and optimising a renewables-based system cost-effectively.* We proposed to strengthen locational investment and operational signals in the market by assessing zonal pricing and alternative options under national pricing, including network charging and transmission access reforms. We also committed to continue assessing centralised dispatch, a reformed Balancing Mechanism, and other reforms such as shorter settlement periods.

**Options Compatibility and Legacy Arrangements:** We assessed and concluded there was a high degree of compatibility between the remaining REMA reform options, while seeking views on this assessment and any other interactions which should be considered. We also provided an initial approach for considering and managing the impact of REMA reforms on existing assets and arrangements.

This Autumn Update marks the next step in providing the market with greater clarity on the future direction of REMA reforms.

## REMA and the Clean Power 2030 Action Plan

The Clean Power 2030 Action Plan sets out how policies will drive the necessary investment in renewables, low-carbon flexibility, and timely build-out of network infrastructure to meet our 2030 target and deliver value for consumers. In the Electricity Market Reform chapter of the Clean Power 2030 Action Plan, we outline shorter-term market measures which will help this mission:

- **Supporting investor certainty** by ensuring wholesale market reform, as being developed under REMA, are delivered quickly and progress towards delivery is communicated clearly. We will do this by having published this REMA Autumn Update and committing to a decision across the REMA programme by around mid-2025 and in time for the next CfD allocation round (AR7);
- **Reforming the CM** to provide clear and viable routes to decarbonisation for unabated gas, enable low-carbon flexible capacity, including consumer-led flexibility to increase its contribution to security of supply, and incentivise investment into existing capacity;
- **Accelerating reforms to balancing markets, maintaining system operability, and reforms to network charging to ensure that the electricity system can be operated securely and cost effectively.** The NESO will continue developing short- and medium-

term balancing service markets and explore constraint management measures. The NESO is also leading on a Constraints Collaboration Project with industry. To help drive investment in renewables, Ofgem will implement shorter-term reforms to the network charging regime. Ofgem published an open letter to industry on 30 September encouraging the NESO to develop a temporary cap-and-floor solution to the projected increasing cost and volatility of Transmission Network Use of System (TNUoS) charges;<sup>3</sup> and

- **Unlocking the full potential of consumer-led flexibility** through timely delivery of Market-wide Half Hourly Settlement in the retail market.

Together, the measures outlined above will help unlock investment in low-carbon generation and flexibility, while driving efficiencies in market operation pre-2030.

In the Clean Power 2030 Action Plan we also set out wider policy actions underway to accelerate the pace of network build, reduce connection timescales, and make the retail market work better for consumers. These actions will work alongside market-focused actions as part of a ‘whole system’ approach to deliver clean power by 2030 and will also set the scene for delivery of longer-term electricity market reform through REMA. They include:

- **To reduce connection timescales, we will work with the NESO and Ofgem to change the grid connections process** to operationalise the Action Plan, by allowing the NESO to prioritise projects that align with strategic plans, going beyond existing ‘first ready, first connected’ proposals;
- **To accelerate the pace of network build and streamline future network expansion we are seeking to fundamentally reform the connections process**, working with the NESO, Ofgem, Transmission Owners, and Distribution Network Operators to prioritise viable projects that align with the Clean Power 2030 Action Plan. To support the delivery of the 2030 target, regulatory reform is needed to integrate the 2030 mission into planning and investment decision making, including appropriateness of current incentive/penalty regime of the regulatory framework. Additionally, improvements in network planning and consenting processes are needed to provide the levers to accelerate the expansion and upgrades required across our transmission and distribution network. Engaging with local communities is also crucial, ensuring they can benefit from living near new transmission network infrastructure and understand its importance to delivering net zero; and
- **As the main interface between consumers and the energy system, we are pursuing targeted reforms to make the retail market work better for consumers.** These changes will equip retailers (both domestic and non-domestic) with the tools and incentives needed to bring forward products and services better tailored to consumer needs and will be key in promoting more widespread flexibility.

We must also consider the future system that will support and drive the transition to a net zero economy by 2050. **The inefficiencies in our current market arrangements are evident. A ‘do-nothing’ approach is not an option.** Long-term reforms will be needed to our underlying wholesale market arrangements. This could be through a reformed national pricing market, or a zonal one. CfDs will need to maintain investor confidence to support the continued

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<sup>3</sup> [https://www.ofgem.gov.uk/sites/default/files/2024-09/Open\\_letter\\_TNUoS\\_intervention\\_vF\\_Publications.pdf](https://www.ofgem.gov.uk/sites/default/files/2024-09/Open_letter_TNUoS_intervention_vF_Publications.pdf).

deployment of renewable generation, and we must ensure security of supply is reliably met while transitioning from gas generation to low-carbon flexibility.

In the longer-term, our work on electricity market reform will continue to work alongside wider policy actions in the areas described above, as well as work underway to take a more coordinated approach to spatial planning for energy infrastructure. The NESO is developing the SSEP, the first ever spatial energy plan for GB, to support a more actively planned approach to energy infrastructure across GB, across both land and sea. The SSEP will need to work alongside whichever reforms REMA introduces, including in relation to the locational signals which would be provided under either a zonal or national wholesale market. This balanced approach to the power system, combining a greater role for strategic planning with more effective market signals, will result in a more resilient, adaptive electricity system, which is capable of meeting future demands at lower costs for consumers.

## Summary of REMA Proposals

### Chapter 1: Wholesale Market Reform

We have significantly narrowed the number of options we are considering for wholesale market reform. **No decision has yet been taken between zonal pricing or reformed national pricing.** Both remain viable options which are being explored further and remain under equal consideration. However, it is clear that ‘no change’ is not an option, in any scenario. Ahead of a final decision, in this chapter, we provide further clarity on how a zonal and a reformed national market might be designed, to help provide greater clarity for investors and other market participants.

For zonal pricing, we provide details for how a GB zonal market might be designed and operate. This includes trading and balancing arrangements and the process for setting zonal boundaries, considerations regarding consumer shielding from variations in electricity price across zones, and management of risk exposure for generators.

For a reformed national pricing market, our lead option is to work with Ofgem to strengthen network charging alongside incremental reforms to balancing incentives as a supporting option. While both zonal and reformed national pricing options will need to work with the SSEP, under reformed national pricing there would likely be a need for greater action to steer where new generation capacity is located through non-market levers. We are discounting reform to network access rights arrangements for generators due to concerns about the impacts on efficient market operation, although we are continuing to explore this option for new two-way flexible assets, such as storage. We have also not identified any feasible unilateral options to significantly improve the flow of interconnectors in relation to GB network constraints under national pricing. Overall, this means our assessment shows, under national pricing, potential locational operational signals would be limited in scope and efficacy.

Across both of these market design options, we are minded not to continue considering centralised dispatch. We will continue to consider reforms to settlement periods and balancing arrangements.

## Chapter 2: Legacy and Transitional Arrangements

In this chapter, we provide an update on our scheme-by-scheme analysis of the functional effects and financial impacts on legacy arrangements for the REMA reforms to be introduced. This includes for schemes in development with no existing contracts in place. We can confirm our commitment to treat agreements under the next CfD allocation round (AR7) in the same way as existing CfD agreements, in relation to any legacy or transitional arrangements.

We also state our expectation that for existing and AR7 CfD holders, the reference price would be updated to a zonal reference price in the event of a decision to proceed with zonal pricing. We also outline the potential mitigations we are considering to reduce risk for those currently operating in the market, and to those who are looking to invest in the near-term.

## Chapter 3: Reforming the Contracts for Difference (CfD) Scheme

In this chapter, we provide our latest thinking on the challenges the CfD scheme faces and how it might be best adapted to meet them. We outline that if a decision to reform the CfD is taken through REMA, no substantial changes will be made until AR9 at the earliest.

We are also continuing to consider the potential to address some of the operational distortions caused by the current CfD scheme through greater action by the NESO.

## Chapter 4: Transitioning from Unabated Gas to Low Carbon Flexibility

In this chapter, we provide updates on policies to enable sufficient flexible capacity – both long and short duration. Gas will continue to play an important role in making the system secure during the clean power transition. Retaining sufficient capacity will be vital even as generation hours continue to reduce – effectively pushing gas to a reserve role. Further work continues to identify what additional policies may be required to unlock the opportunities associated with short-duration flexibility. The Government is also taking steps to support the decarbonisation of existing and future assets. We will continue to assess how markets can best support new technologies to be competitive once more established. This includes whether to optimise the design of the CM auction to allow low-carbon flexible technologies access to different clearing prices by introducing minimum procurement targets. As set out in the Clean Power 2030 Action Plan, the reforms we are announcing to existing market frameworks are the best way to ensure that the necessary strategic reserve capacity of unabated gas generation remains on the system. The Government's view is that a novel out-of-the-market mechanism to manage that reserve may have a role in the long-term phase-out of unabated gas capacity once its volume in the system has significantly reduced and long-duration low-carbon flexible technologies have been deployed at scale.

***What does this update mean for investors?***

Securing the continued investment needed to transform our energy system is essential to delivering Clean Power 2030 and our wider net zero objectives. Alongside the Clean Power 2030 Action Plan and ahead of final decisions on the REMA Programme, this publication aims to provide greater clarity to investors about our plans for longer-term electricity market reform, by:

- 1) Confirming the timetable for decisions on final REMA policy will align with the timetable for the next CfD allocation round (AR7);
- 2) Significantly narrowing down the options for future wholesale market reform, including setting out our position that we are not minded to take forward centralised dispatch;
- 3) Setting out our initial thinking on the key aspects of the remaining options for zonal and reformed national pricing where early clarity for investors would be most valuable;
- 4) Outlining our expectation that existing CfD (and AR7) agreements will likely use a zonal reference price if zonal pricing is adopted, insulating these contracts from zonal price risk;
- 5) Confirming our commitment to treat agreements under the next CfD allocation round (AR7) in the same way as existing CfD agreements, in relation to any legacy or transitional arrangements;
- 6) Confirming that if any CfD reforms are taken forward as part of REMA, any significant changes will not be implemented until AR9 at the earliest; and
- 7) Setting out how we plan to ensure that the necessary strategic reserve capacity of unabated gas generation remains on the system.

## Next steps

This document is not a consultation and does not include any formal questions.

We are looking to conclude the policy development phase of the REMA programme by around mid-2025 and will ensure that these REMA timelines align with the timetable for the next CfD allocation round (AR7). We, therefore, plan to announce REMA's final decisions and the timetable for their implementation, particularly in relation to wholesale market reform and any transitional or legacy arrangements, before the AR7 auctions open, giving investors clarity for prospective bids.

We will continue to assess the remaining reform options against the five REMA criteria set out in the March 2024 consultation, which are outlined in the table below, as well as the programme's objectives of security of supply, cost-effectiveness, and decarbonisation.



Criteria	Explanation
Value for Money	Market design should lead to solutions that minimise overall system costs for consumers and sub-groups of consumers, with ongoing incentives to keep costs as low as possible and drive innovation (through competition where appropriate). Markets should be open to all relevant participants, including demand-side and innovative technologies.
Deliverability	Changes to market design should be achievable within designated timeframes and seek to minimise disruption during the transition, taking account of the highly complex and integrated nature of the power system.
Investor Confidence	Market design must drive the significant investment in the full range of low-carbon technologies needed to deliver our objectives. Risks will differ by technology type but should be borne by those best able to manage them.
Whole-System Flexibility	Market design should incentivise market participants of all sizes (both supply and demand) to act flexibly where it is efficient to do so. It should also promote greater coordination across traditional energy system boundaries, including between electricity and other vectors like heat and hydrogen, to enable effective optimisation across the system as a whole.
Adaptability	Market design should be adaptive and responsive to change. It should help ensure delivery of our objectives in a wide range of scenarios and should be robust to uncertainty; for instance, regarding commodity prices and technology costs.

We will continue to engage with stakeholders throughout the next phase of the REMA programme. We are keen to engage with stakeholders on the practicalities of how either zonal pricing or reformed national pricing could be made to work best, including in relation to any transitional or legacy arrangements, ahead of a final decision. If you would like to discuss policies that are part of the programme or would like to be added to our REMA mailing list, please email [REMAMailbox@energysecurity.gov.uk](mailto:REMAMailbox@energysecurity.gov.uk) with your request and the REMA engagement team will manage your query.

# Chapter 1: Wholesale Market Reform

## Summary

Within REMA, we are considering options to ensure GB's future renewables-based electricity system operates efficiently and cost-effectively for investors and consumers. The rapid decarbonisation of our electricity system is creating new challenges which our wholesale market and balancing arrangements must rise to meet.

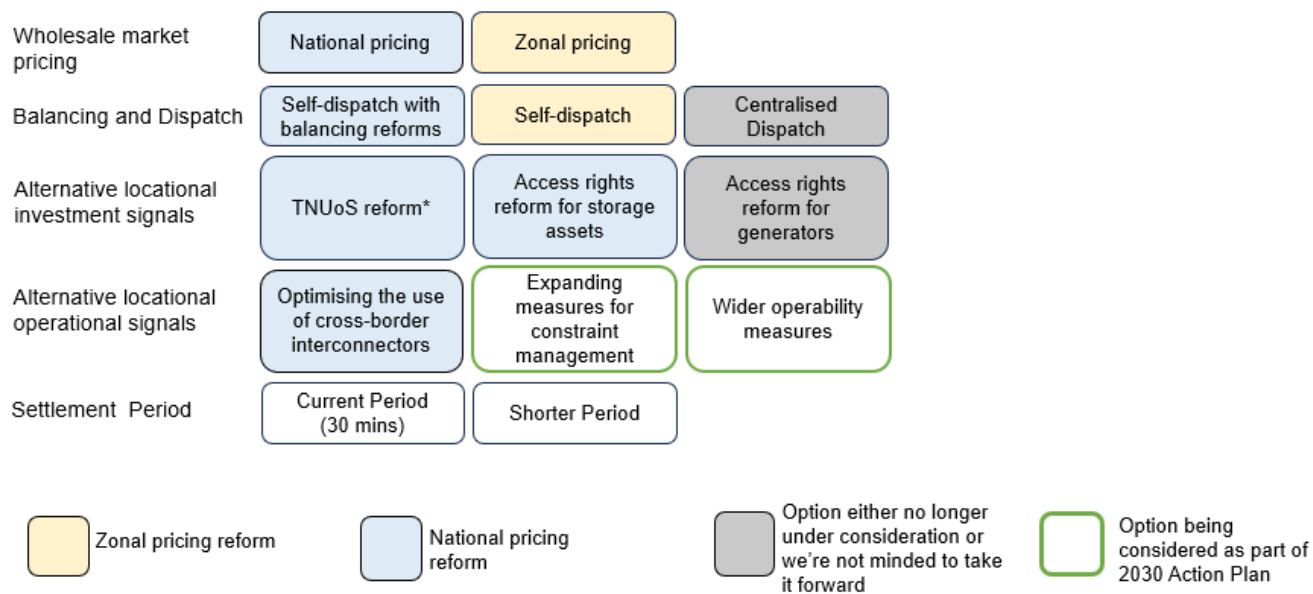
Current wholesale market arrangements do not adequately incentivise market participants to consider network conditions in their investment or operational decisions. This means that we are not making the best use of the significant amounts of renewable generation and network capacity that we are building, both now and in the future. It also limits the potential to maximise whole-system flexibility through assets like storage, demand side response, and interconnection, which can help drive down system costs.

As generation becomes more variable and located further from demand, the NESO must redispatch significantly more generation through the Balancing Mechanism than in the past, arguably beyond the level that our wholesale market arrangements were initially designed for. This is putting growing strain on the NESO's processes and increasing costs to consumers. This challenge is compounded by other issues, such as the NESO's limited visibility of certain assets on the system and the need to optimise dispatch over both location and time. Taken together, these challenges mean that maintaining the status quo – or a 'do nothing approach' – is not an option.

Since publishing REMA's second consultation, we have undertaken an initial qualitative assessment of a wide range of options for wholesale market reform against the REMA assessment criteria. We are also developing a full Cost-Benefit Analysis. Through this work, we have significantly narrowed down the reform options that remain under consideration (see figure below).

At this stage, **no decision has been taken between zonal pricing or reformed national pricing**. They both remain viable options and remain under equal consideration. In this document, we outline the main outstanding questions we are considering, and our current thinking on how either set of reforms could best be designed and implemented if chosen. Under either market design, we are not minded to take forwards centralised dispatch.





\*We would also need to consider the role and design of TNUoS in a zonal market.

## Assessment of Zonal and Reformed National Pricing

In REMA’s second consultation, options were grouped according to the challenge in the wholesale market they were aiming to resolve (improving locational signals, temporal signals, balancing and ancillary services, local and national co-ordination, and market liquidity). To aid assessment against the REMA assessment criteria, we have now qualitatively assessed whether zonal or reformed national pricing reforms, as a whole, could deliver against those key challenges facing the wholesale market; grouped as follows:

<b>Locational operational signals</b>	Does reform incentivise market participants to consider when they consume or generate energy to make the best use of locally available renewable generation and network capacity?
<b>Locational investment signals</b>	Does reform incentivise market participants to consider their location and impact on network constraints when making investment decision?
<b>Dispatch optimisation</b>	Does intervention facilitate optimised dispatch and redispatch decisions?

### Assessment of zonal pricing

Our initial assessment shows zonal pricing could effectively address the key challenges noted above. It is also the only option which significantly improves locational operational signals for market participants.

Differential wholesale price signals in a zonal market could help incentivise more locationally responsive investment for those assets which are able to respond; for example, through

decisions on where and when to invest, co-location, or asset design and optimisation. Locational operational signals could help to optimise the use of flexible technologies, such as interconnectors and storage, and while also enabling consumers to take advantage of the potential ‘surplus’ cheap renewable generation which is likely to occur at times. The need to address improvements to dispatch optimisation should also decrease as the overall need for redispatch reduces with more efficient locational balancing.

Together, these signals have the potential to contribute to a reduction in system costs and lower bills for consumers. They could also reduce the overall size of the system required to meet net zero by allowing us to make the most efficient use of the network infrastructure and low-carbon generation we are building.

However, zonal pricing would also transfer some locational risk to generators. This could lead to an increase in risks for some market participants which could also affect the cost of capital. Introducing zonal pricing would also represent a major change to our electricity market arrangements and would take some years to deliver. Without sufficient early clarity and appropriate transitional and legacy arrangements for investors, the resulting uncertainty could further increase the cost of capital.

The scale and duration of the potential impacts of zonal pricing on cost of capital is currently unclear and subject to further analysis. However, any potential increase to the cost of capital could impact the benefits case for zonal pricing. We will take these factors into account in our Cost-Benefit Analysis and in final decisions on whether to introduce zonal pricing or reformed national pricing.

We will, therefore, need to identify a design of a zonal pricing market which is deliverable and suitably allocates risks to those who could best bear them. Ahead of final decisions, we will continue our engagement with investors, generators, and other stakeholders on how best to design any zonal pricing and reformed national pricing model, and legacy and transitional arrangements. We also continue to seek feedback on how best we can provide as much clarity as possible to investors during the period ahead of any potential decision on wholesale market reform.

In this document, we have set out our progress so far on a potential design of zonal pricing for GB. This should be considered in context of legacy and transitional arrangements in Chapter 2.

### ***What might zonal pricing mean for consumers?***

Zonal pricing aims to reduce consumer bills by lowering the overall cost of the energy system. The savings from designing a more efficient system should in theory pass through to the average consumer.

If zonal prices were passed through to consumers, it could also give both domestic and non-domestic consumers the opportunity to take greater control of their energy consumption. More efficient locational price signals give consumers the opportunity to take advantage of times when *local*, cheap renewable energy is abundant, rather than costs being determined by the *national* supply and demand.

For instance, this would mean consumers in the South-West could charge their electric vehicles when it is sunny in the southwest, and those in Scotland could benefit when local wind farms are producing abundant cheap generation. This would always be on a voluntary basis and could happen through suppliers rather than being a demand on consumers.

Enabling consumers to access the *locational value* of their energy consumption by making better use of the 'surplus' electricity in a particular area, which cannot be exported due to network constraints, would not just benefit those individual consumers but would also reduce the cost of the system as a whole. It would also alleviate stress on the network, reducing the actions that the NESO are required to take to keep the system in balance. This could mean lower costs for all consumers regardless of whether they chose to take advantage of periods of surplus renewable generation.

Enabling consumers to access the locational value of their energy usage could also affect what technologies they use such as EVs, or for businesses, the electrification of industrial processes. It could also help bolster regional growth through new investment in electro-intensive technologies, such as data centres or green hydrogen electrolyzers, in areas with lower wholesale prices.

However, it is also important to consider the impact on consumers and businesses in the round and the differing capacities to engage with consumer-led flexibility. These issues will all form part of our assessment, as we move towards final decisions.

### **Assessment of reformed national pricing**

On reformed national pricing, we have significantly narrowed the range of market options we are considering and have now identified a lead package consisting mainly of reform to transmission charging and balancing incentives. Our initial assessment shows reforms under national pricing could help to send a stronger and more predictable locational investment signal than currently exists. However, they would be very limited in their ability to improve locational operational signals. There are some measures under national pricing which could improve dispatch optimisation, but they vary in the extent of their effectiveness – the potential scale of reforms to balancing arrangements may be limited, while reform to introduce more centralised forms of dispatch present deliverability challenges.

These limitations mean that if reformed national pricing were to be introduced, we would also likely need to further strengthen existing policy measures being considered outside of the market, beyond those proposed in the Clean Power 2030 Action Plan. These levers primarily affect the locational investment signals sent to newbuild generation. This could include further strengthening plans for centralised system and generation planning (for example, through the SSEP) and reforms to the connections regime. The measures proposed in the Clean Power 2030 Action Plan would represent significant progress on the role strategic planning can play in ensuring new generation is located in the right place, but further steps could still be needed. Planning and connection reform measures would also be needed under zonal pricing, but to a lesser extent. It is also possible under a reformed national pricing system that we may need a

larger electricity system compared to zonal pricing, both in terms of generation and network build.

National pricing compared to zonal pricing has both challenges and advantages. Under reformed national pricing, even with these additional interventions outside of the market, it is likely we would also have to tolerate a significant degree of unresolved market issues on an ongoing basis under a reformed national pricing market. These would have associated costs to consumers. This could include an increased need for redispatch due to the lack of locational operational signals and the inefficient operation of flexible assets which can sometimes exacerbate constraints. Managing redispatch is already expensive and complex for the NESO, and the cost and complexity is likely to increase in future. Though these issues would remain unresolved through the market, this is not to say they would be unmanageable. The cost of continuing to manage these unresolved market issues will need to be weighed against the risks and full Cost-Benefit Analysis of a potential move to zonal pricing.

On the other hand, a reformed national pricing market would be less complex to implement and would be less disruptive for investors and their cost of capital than zonal pricing. Once we have completed our assessment of the different options and further developed our Cost-Benefit Analysis, it is possible that delivering some benefits through a reformed national pricing market alongside tolerating some of its inefficiencies strikes a better balance for delivering our objectives, including on reducing consumer costs, compared to a zonal market and associated risks.

Therefore, **both sets of reform remain viable options and are under equal consideration.** As with zonal pricing, we are committed to identifying a reformed national pricing package that is deliverable and minimises overall system costs, and we are continuing to consider transitional and legacy arrangements under reformed national pricing. The sections below set out in detail our initial assessment of zonal pricing, reformed national pricing, and options which could apply under either.

## Zonal pricing design

As outlined in REMA's second consultation, we are exploring several aspects of zonal design. These have since been updated. We are now considering the following two groups of design choices:

Zonal Design Choice	Current Position
<b>Group 1 – Operation and Design</b>	
Zonal boundaries	<p>Zonal boundaries would be drawn based on independent assessment of network congestion close to the point of delivery. This means we are <b>not able to give the exact number of locational of zonal boundaries at this stage.</b></p> <p>We are continuing work on defining a potential methodology for setting zonal boundaries.</p>
Trading and balancing	<p>We are <b>not currently minded to take forward centralised dispatch</b>, and are, therefore, assuming balancing and trading would be based on a self-dispatch concept.</p> <p>We are continuing work to define how trading and balancing would work in practice under zonal.</p>
<b>Group 2 – Market Exposure</b>	
Generation risk exposure	<p>We are carefully considering how the risk profile for generators would change in a zonal market and the degree of locational risk they should be exposed to.</p> <p>We are <b>continuing to assess what additional mitigations could help generators to effectively manage risk.</b> This includes legacy and transitional arrangements, government support schemes (such as the CfD), and hedging mechanisms.</p>
Demand-side exposure	<p>We will need to carefully consider how the benefits of any transition should be distributed between consumers.</p> <p><b>We are continuing to assess mechanisms which could be used to shield consumers from zonal price variations, if our assessment shows this is desirable.</b></p>

**Group 1 – Operation and Design: Choices which affect how a zonal market is designed and will operate.**

There are many elements which would need to be considered in the design of a potential zonal market. For now, we are focusing on those which we think are most important to define to provide early clarity to market participants. The exact details of some of the design areas would be decided during any potential implementation phase of zonal pricing, Despite this, we

are considering how we can give as much clarity to investors as early as possible, if we were to decide to adopt zonal pricing. The design choices we are considering in this area are:

- **Zonal boundaries** – determining the approach to drawing and reviewing zonal boundaries.

A zonal market could have fewer or a greater number of zones, with more zones sending more accurate locational signals. Zonal boundaries would be drawn based on an independent assessment of the underlying congestion in the network to capture the most significant constraints. Should we pursue zonal pricing, a methodology for setting zonal boundaries would be proposed as part of a transparent and predictable process. The need to undergo an independent process and ensure zonal boundaries reflect the relevant network constraints at the time of delivery means that, if we were to opt for a zonal market, we would not be able to provide an exact number or location of zonal boundaries at this stage. However, we would aim to provide as much early clarity as possible on any potential proposed methodology.

Within each zone, we would also need to consider the role of TNUoS, which would likely need to adapt to a zonal wholesale market. The better that zonal boundaries reflect underlying network conditions, the less need there would be for generator TNUoS to send locational price signals. Locational TNUoS charges could, therefore, be smaller in a zonal system, although they may still be needed to send some within-zone locational signals.

- **Trading and balancing** – determining how market participants would trade physically and financially across different timescales, between zones and cross-border, and how the system would be balanced.

As we are not currently minded to take forward centralised dispatch, our assumption is that balancing and trading arrangements under zonal pricing would be based on a self-dispatch concept, as exists today. This would mean that under zonal pricing with self-dispatch:

- Generators would only have firm access rights within their zone, as opposed to current national pricing arrangements. When selling power, generators would have access to the prevailing price in their zone; and
- A Market Operator would be responsible for allocating transmission capacity for the flow of electricity between zones. The allocation of capacity would be implicit in the day ahead and intraday markets, meaning cross-zonal capacity would be taken into account and cross-zonal flows determined as part of the cross-zonal trade of electricity. As part of this, Power Exchanges and the NESO would work together to calculate and allocate network capacity. We would ensure that these arrangements would be compatible with cross-border trading arrangements.

We continue work to define how this would work in practice, taking into account issues like forward and spot market trading, inter-zonal capacity allocation, cross-border trading, redispatch, and imbalance settlement. We are looking to existing international zonal markets to inform this work.

**Group 2 – Market Exposure: Choices which affect the level of exposure which market participants may be exposed to.**



These choices will be informed by our ongoing Cost-Benefit Analysis and assessment of appropriate risk allocation. Choices should help ensure that any potential zonal system delivers a more efficient system overall and would achieve our objectives at least cost.

- **Generation risk exposure** – determining the level and type of risk generators should be exposed to (and considering the instruments to mitigate these risks).

We are carefully considering how the risk profile for market participants, including generators, would change in a zonal market and the degree of locational risk exposure they should be exposed to. Currently, locational risk is borne by consumers through balancing costs. Zonal pricing would transfer some of this risk to generators, to differing extents depending on certain design choices. Therefore, a crucial part of our assessment will be ensuring that risks and incentives in the future electricity market fall where they can best be managed and responded to.

Zonal pricing would transfer risk to generators by exposing them to locational price and/or volume risk, with the aim of driving better locational investment and operational decisions. While the exact response to signals will vary by site and asset type, there are ways in which generators could respond to these signals. For example, generators could alter investment, asset design and optimisation, trading, and dispatch decisions to take advantage of the local wholesale prices in their zones. Two-way flexible generators, such as batteries, may be able to take advantage of greater opportunities for arbitrage, as the locational operational signals in the wholesale market should be more transparent than in the Balancing Mechanism.

Generators are better placed than consumers to respond to these locational signals, and, as such, should be able to take decisions which can help drive down total system costs. However, we recognise some generators will be more limited than others in their ability to respond to these signals. As a result, they would face greater risk exposure under zonal pricing than they do at present. We are, therefore, also carefully considering what additional mitigations could help generators to effectively manage risk exposure while still delivering value for consumers. There are several options we are currently assessing. If our assessment shows that these possible mitigation tools prove effective in allowing generators to manage risks effectively, while still delivering value for consumers, we will consider this in any final market design.

**Legacy and transitional arrangements.** In Chapter 2, we update on our approach to legacy and transitional arrangements. We can confirm our commitment to treat agreements under the next CfD allocation round (AR7) in the same way as existing CfD agreements, in relation to any legacy or transitional arrangements. We state our expectation that for existing and AR7 CfD holders, the reference price would be updated to a zonal reference price in the event of a decision to proceed with zonal pricing. Strike Prices would be unaffected. As a result, existing and AR7 CfD generators would receive difference payments reflective of the zone in which they were generating and be insulated from zonal price risk. We also outline the potential mitigations we are considering to reduce risk for those currently operating in the market, as well as to those who are looking to invest in the near-term.

**Government support schemes (such as the CfD).** As outlined in the second REMA consultation, different options for future proofing the CfD may expose renewables to new

locational price and volume risks to different extents. We are continuing to explore options for CfD reform. An update is provided in Chapter 3. We are also considering the compatibility of other support schemes with zonal pricing.

**Hedging mechanisms (such as financial transmission rights).** Since the second consultation, we have explored in more detail the pros and cons of cross-zonal hedging products to address cross-zonal price risk in a zonal market, where buyers and sellers of electricity may need to offset (i.e. hedge) the price differential between two zones.

One of the potential products are Financial Transmission Rights (FTRs). FTRs are a type of hedging product which are typically issued by the System Operator (SO) following a competitive auction. The holder of an FTR is entitled to receive a financial payout equal to the outturn price difference between the two zones they are trading between. There are two main types of FTR product. The first is an ‘FTR option’, which entitles the holder to receive a financial payout equal to the price difference between the two zones. The second is an ‘FTR obligation’, which is similar to an FTR option, but holders must pay back the difference if the price differential is negative.

It is important that any cross-zonal hedging products reflect the needs of market participants. We will work with industry during this next phase of the REMA programme to better understand their requirements. We are aware of concerns around the suitability of FTRs for intermittent generation sources and we are considering how a potential GB FTR market could be designed to better suit these needs. We are still undertaking our assessment of how an FTR market might be introduced and how this might compare to other options for enabling the hedging of risks.

On liquidity, we have listened to stakeholder concerns around the potential loss of liquidity through market fragmentation if zonal pricing was to be introduced. We are considering options for the potential introduction of virtual trading hubs, with the aim of pooling liquidity and supporting trading activity through a robust and transparent reference price. A virtual trading hub is determined as an average or index of prices of the areas captured within the hub.

There are different ways a hub price can be calculated. One option is an unconstrained system price which assumes no transmission limits between zones. For example, the Nordic system price takes aggregated and anonymised data from Nordic bidding zones and assumes unlimited transmission capacity between them to provide a benchmark price. Another option is a load-weighted average price. To calculate this type of hub price, data would be used from a selection of neighbouring zones with the constituent zones weighted depending on their level of demand. Depending on whether we proceed with the creation of an FTR market, we will consider whether to price FTRs against a virtual trading hub.

- **Consumer exposure to zonal price variations** – determining the appropriate level of consumer exposure to locational signals (and considering the model of consumer shielding required).

There are important decisions for the Government to make on how the benefits of any transition to zonal pricing should be distributed between consumers. There are mechanisms



that could be introduced which could limit or eliminate differences in wholesale prices between zones for consumers. For example, a reconciliation mechanism could be used to redistribute savings from areas which might benefit the most to those which otherwise might see smaller benefits. This would still maintain a location-specific time of use incentive but could be used to equalise or reduce any difference between average retail prices in different zones. Through such mechanisms, many of the benefits of zonal pricing could be retained even with additional measures for consumer protection, as they would still enable consumers on time of use tariffs to respond to locational price signals to reduce their bills.

Any decision on whether to shield consumers from these price differentials would need to be supported by further quantitative analysis. The distributional impacts of zonal pricing should not be considered in isolation, but as part of a broader overall approach to energy affordability. This includes measures to protect low income and vulnerable consumers. We will work with Ofgem to consider the impact of different zonal pricing options alongside other drivers of regional differences in consumers' bills, including network charges.

The Government also recognises the importance of making sure electricity prices are internationally competitive. We are aware that some Energy Intensive Industries (EIs) may be affected by zonal pricing differently to other businesses. While zonal pricing could create opportunities for EIs to reduce costs, we recognise this may not be equally true for all production processes. We also recognise that existing EIs will not be able to change their location to take advantage of lower wholesale prices. Additionally, zonal pricing would also change the composition of electricity bills, for instance by moving some costs from the current Balancing Mechanism into wholesale prices. This could have implications for compensations, such as the British Industry Supercharger, which some EIs currently receive from a portion of network and balancing costs. We are working to ensure such impacts are considered in our decision making.

We will work closely with consumers and industry groups to consider any distributional issues for domestic or non-domestic consumers and whether shielding consumers would be desirable. Any final decisions will include assessment and consideration of distributional impacts.

## Reformed National Pricing Design and Assessment

The table below summarises the options that we have considered under reformed national pricing and outlines our current position on them.

Reformed National Pricing Option	Current Position
Reforming network charges – TNUoS and DUoS (Distribution Use of System charge)	Our <b>lead option</b> for sending locational signals in a reformed national market is through TNUoS reform. <sup>4</sup>  Ofgem's DUoS charging review continues and will be subject to the approach taken on TNUoS.
Incremental reforms to the NESO's balancing arrangements under national pricing	We are <b>continuing to consider</b> these options as supporting options. We have discounted the possibility of a longer gate closure.
Improving the flow of interconnectors relative to network constraints under national pricing	We have <b>not been able to identify</b> any reforms under reformed national pricing which could significantly improve the flows of interconnectors in relation to GB network constraints. We are continuing to support the NESO with the use of existing tools to manage interconnector flows, and to discuss with interconnected parties' options which would benefit consumers on both sides of the interconnector.
Reforms to transmission network access arrangements	We are <b>no longer considering reforms</b> to transmission network access rights under reformed national pricing, other than for new storage projects.

## Reforms to Network Charging Arrangements

Under current arrangements, GB generators already face a locational investment signal through TNUoS charges. The annual charge is perceived to be unpredictable for investors, and the existing methodology to determine locational TNUoS differences is not deemed to be cost reflective. The current methodology means zones further away from demand pay higher locational charges. However, this does not reflect factors, such as impacts on network constraint costs or available network capacity.

Ofgem have assessed potential reforms to address these issues as part of their longer-term strategic review of transmission charging, with the aim of sending a more effective locational

<sup>4</sup> TNUoS would also need to be adapted in a zonal market. This is being considered as part of Ofgem's Strategic Review of Transmission charging.

investment signal.<sup>5</sup> Ofgem have agreed to conclude decision-making on the review in the same timeframes as REMA decision-making. Reforms to network charging may differ under a national and zonal pricing scenario.

At a high-level, Ofgem’s preferred reforms to network charging under a national pricing scenario would be to:

**Improve TNUoS cost driver accuracy and predictability.** This would include two potential reforms to TNUoS. The first would be to reform the locational charge methodology to better reflect where there is existing unconstrained or spare capacity on the network. This would mean generators would be incentivised to locate either where there was available capacity or face a higher charge which better reflects the actual effect they would have on the network – for example, if siting in a location with limited capacity, which may result in the increased need for network reinforcement or higher constraint costs. The second option would be to use a more forward-looking network design to calculate charges. This would improve the predictability of charges by limiting near-term unforeseeable changes in costs due to changes in network build, thus increasing investment certainty.

**Change the allocation of costs across TNUoS and connection charges.** Currently GB generators connecting to the transmission network pay a connection charge for the immediate assets used to facilitate their connection. The ‘shallow’ nature of current connection charges means that irrespective of constraints – or network capacity – a generator may only face a small proportion of the reinforcement costs they trigger. Ofgem are considering changing this arrangement so that generators face some or all the reinforcement works triggered by their choice of location, with an option to include ‘local’ charges within the connection charging regime. Given that these costs would be part of a fixed and pre-determined connection charge, this would send a stronger and more predictable locational signal for generators. Ofgem is carefully considering different implementation approaches. This includes arrangements that should apply where a second generator utilises an asset that has already been paid for by the first.

These options are still being developed and assessed through Ofgem’s review. We are committed to continue to work with Ofgem to develop these policy options. Ofgem have committed to conclude their policy thinking in line with REMA timeframes. Ofgem’s DUoS charging review continues and will be informed by the approach taken on TNUoS through REMA. We and Ofgem recognise the need for coherent and complementary arrangements. We will carefully consider the impact of any changes to network charging arrangements on the British Industry Supercharger which provides a reduction in network charges for certain EILs.

Ofgem have recently published an open letter<sup>6</sup> on a proposed code modification to introduce a temporary cap and floor amendment to TNUoS generator tariffs. The purpose of this modification is to minimise system cost for consumers, while reducing uncertainty to investors

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<sup>5</sup> Ofgem reaffirmed their position that TNUoS is not an appropriate mechanism to send operational signals in an open letter published in September 2023: [Open letter on strategic transmission charging reform: a summary of responses | Ofgem](#).

<sup>6</sup> <https://www.ofgem.gov.uk/publications/seeking-industry-action-mitigate-investment-impacts-very-high-projected-tnuos-charges>.

to deliver Clean Power by 2030. This is ultimately an industry modification process, but Ofgem, as decision maker, will help ensure a smooth transition into any future arrangements under REMA.

## Incremental Reforms to Balancing Arrangements Under National Pricing

We are working closely with the NESO to assess options which could help to improve balancing incentives for market participants under self-dispatch arrangements. The purpose of these options would be to make it easier for the NESO to balance the system; for example, by incentivising market participants to ‘self-balance’ (minimise differences between contracted and metered positions). These reforms are subject to further assessment, but we expect they would deliver more limited benefits relative to the operational challenges in the market and compared to zonal pricing. If implemented, they would support reforms to network charging as set out above.

The options being considering include (but are not limited to):

- Returning to a dual imbalance price, to manage issues around Net Imbalance Volume chasing and constraint management;
- Lowering the threshold for mandatory participation in the Balancing Mechanism, to facilitate redispatch;
- Realigning Gate Closure with the deadline for market trading, to give the control room more certainty; and
- Reducing the settlement period duration.

We considered the option of extending gate closure, as raised as an option by the NESO in their publication on ‘scheduling and dispatch’,<sup>7</sup> but discounted it on the grounds that it would not create significant operational efficiency savings.

## Improving the Flow of Interconnectors Relative to Network Constraints

Given the potentially significant benefits of zonal pricing for the improved flow of interconnectors relative to network constraints, we have assessed a wide range of options under a reformed national pricing scenario. These options included introducing applying network charges to interconnectors and allowing interconnectors to directly participate in the domestic Balancing Mechanism.

We have concluded that **there is very little that can be done unilaterally in GB under reformed national pricing** to improve the flow of interconnectors. This is because of requirements under international agreements with the EU and Norway, which are designed to support efficient trade and cooperation, and the need to consider the impact and dependencies on interconnected countries.

We are working with the NESO to ensure that they can effectively utilise the existing tools that are available to them to manage interconnector flows. This includes SO-to-SO trading,

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<sup>7</sup> <https://www.neso.energy/about/our-projects/net-zero-market-reform>.

countertrading, and considering whether interconnectors could participate in constraints markets. The latter is being explored through the NESO's ongoing Constraint Collaboration Project. We will also continue to review options for GB-EU balancing arrangements. While effective use of these options may support management of interconnectors with respect to constraints, we expect the benefits they could deliver would be limited in comparison to those delivered by zonal pricing. This would mean that under reformed national pricing, interconnector flows in relation to constraints would continue to contribute to the wider challenge the NESO faces in managing the network, which would have to be resolved at cost to GB consumers.

We note that under all REMA scenarios, interconnectors are, and will continue to be, an important component of GB's energy capacity mix and for supporting GB's transition to net zero. We are continuing to assess interactions between specific REMA reforms and our international trading obligations for electricity trading and cooperation, including those in the UK-EU Trade and Cooperation Agreement (TCA).

### Reforms to Transmission Network Access Arrangements Under National Pricing for New Generators

Under the current 'Connect and Manage' arrangements, generators receive financially firm access to the transmission network once they are ready to connect, even if physical network capacity is not currently available in sufficient quantity. These access rights mean asset owners are entitled to compensation if the transmission network cannot physically accommodate or transport the energy that asset is producing.

Since REMA's second consultation, Ofgem have undertaken an assessment of several options for restricting the offer of financially firm access rights for new generators choosing to locate in constrained part of the network. The purpose of this reform is to send a stronger locational investment signal.

Based on our initial assessment of these options, **we are no longer considering reforms to transmission network access rights for new generators under reformed national pricing.** This is due to concerns that introducing non-firm access rights for these assets could lead to operational inefficiencies and would only provide an incomplete locational signal.

Restricting financially firm access rights for some new assets could lead to operational inefficiencies in the Balancing Mechanism and challenges for the NESO due to the introduction of a 'two-tier' access rights regime. Holders of non-firm rights would likely be newer, cheaper low-carbon assets. A 'two-tier' system could materialise, however, if these cheaper non-firm rights holders are constrained down first ahead of plants holding firm rights, resulting in higher overall dispatch costs.

We have considered options to mitigate this inefficiency, such as introducing rules to influence which type of assets the NESO prioritises 'turning down' when making curtailment decisions (i.e. curtailing low-carbon assets last). However, our assessment shows that such options would likely weaken the locational investment signal which the reform is intended to send.

Additionally, restricting the offer of firm access rights alone may not be able to provide a complete locational signal. This is because while it may signal *where not* to locate (i.e. in constrained areas), it does not signal where it is most beneficial *to* locate.

We recognise that the balance of risk to reward of restricting firm access offers may be more reasonable for new storage assets, although there are other potential limitations which need to be considered. There is scope to investigate this further in the future, if a reformed national pricing design is selected as the preferred REMA option.

## Assessment of Options that Could Apply Under Both Reformed National Pricing and Zonal Pricing

The table below summarises the options that could apply under both reformed national pricing or zonal pricing and which were kept on the table in REMA’s second consultation. The table also outlines our current position on them.

<b>Reforms Options Under Both Zonal and Reformed National Pricing</b>	<b>Current Position</b>
Centralised dispatch	We are <b>not minded to take forward centralised dispatch</b> under either reformed national pricing or zonal pricing at this stage, but are open to considering the evidence that the NESO are gathering on it.
Reforms to settlement periods	We are <b>still considering the case for shorter settlement periods</b> under both reformed national pricing and zonal pricing.
Expanded measures for constraint management	We are continuing to consider these options with the NESO as part of the <b>Clean Power 2030 Action Plan</b> through the NESO’s Constraints Collaboration Project.
Wider operability measures	We are continuing to consider these options as part of the <b>Clean Power 2030 Action Plan</b> .

## Central Dispatch

Since REMA's second consultation, we have assessed variants<sup>8</sup> of centralised dispatch as a possible method for improving operational efficiency under both national and reformed zonal pricing. Overall, **we are not minded to take forward centralised dispatch** due to concerns over deliverability, investor confidence, and value for money.

Centralised dispatch may have benefits for managing high volumes of congestion cost-effectively, especially for enabling co-optimisation of energy and ancillary services. These benefits could be of greater value under a reformed national pricing scenario compared to zonal pricing. As part of the REMA programme, the NESO are continuing to assess the scale of potential benefits of central dispatch, under both national and zonal pricing.

However, the initial assessment shows that the option would be very challenging to deliver. This is particularly with regards to cross-border arrangements, given our obligations under international agreements, including in the UK-EU TCA. It could also create significant challenges for developers and investors.

## Reforms to Settlement Periods

We are continuing to assess the merits of shortening the settlement period duration (e.g. to 5 or 15 minutes) to create a more 'granular' wholesale market temporal signal. This could lead to greater market participation by smaller and innovative flexible assets, including Demand-Side Response, and reduce overall costs by moving volumes out of the Balancing Mechanism and into the wholesale market. However, shortening the settlement period duration would raise several deliverability challenges, including for energy suppliers and their interactions within the retail market.

## Expanding Constraint Management Measures and Addressing Wider Operability Measures

In the second consultation, we noted that we were considering specific constraints management measures to reduce the cost of constraints. The NESO's ongoing Constraints Collaboration project with industry is informing our understanding of the potential for more effective action. We also explored options specifically for promoting efficiency and investment in low-carbon ancillary services for meeting the needs of a system increasingly dominated by intermittent renewable energy. These options could help to reduce system costs, and it is possible that some of these reforms would be introduced ahead of wider wholesale market reform. These constraint management and operability options are, therefore, being considered further as part of the 2030 Clean Power Action Plan. We will consider the outcomes as part of the REMA programme.

## Wider system dependencies and non-market levers

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<sup>8</sup> In line with the work that the ESO published on its website as part of its Scheduling and Dispatch Options Webinar in July 2024, we have considered 'hybrid' and 'gross pool' variants of centralised dispatch. See: <https://www.neso.energy/about/our-projects/net-zero-market-reform>.



As set out above, we would also need to consider the impacts on other parts of the GB energy system and other policy levers, depending on whether either zonal pricing or reformed national pricing was adopted. Under reformed national pricing we would likely need to rely more on non-market levers, such as the SSEP or the connections regime, to send even stronger locational investment signals than under current plans.

Managing operability in a clean power system will require different and innovative approaches. We will work closely with the NESO and industry, to help ensure that an increasingly distributed and complex electricity system is operated and managed reliably and efficiently, under either a reformed national or zonal pricing scenario. As part of the final REMA decisions, we will ensure that the interactions of our electricity market arrangements with other policy areas and non-market levers are taken fully into account, so that they are aligned and provide coherent signals to investors and market participants.



## Chapter 2: Legacy and Transitional Arrangements

### Summary

We understand through the responses to REMA's second consultation and our ongoing engagement with investors and other market participants that introducing any changes to a market naturally causes uncertainty for investors and those operating in the current market. As well as considering the potential benefits for the system and consumers from reforming our electricity market arrangements, the Government is also taking account of issues relating to potential cost of capital increases, expected returns on investment (for both debt and equity), the pace of renewables deployment, the ability to trade, and international competition.

These concerns highlight important considerations, and the Government recognises that both past and present investors in GB low-carbon energy are also the investors of the future. Having considered this feedback, we are keen to minimise uncertainty that any reform to our electricity market arrangements might naturally cause.

We understand that all investors want to have as much certainty as possible about the effect that any reforms might have and will want reassurance about what reforms mean for their previous investments. This will be important for ensuring continued future investment enabling the delivery of a low-carbon-based system at pace and for achieving clean power by 2030. Therefore, for both zonal and reformed national pricing, we are keen to ensure that we can provide as much early clarity on key design parameters and implementation timetables as possible, which would limit any uncertainty faced by project developers during this transitional period.

In addition, as part of the final decisions on the market arrangements to be implemented through REMA reforms, we will announce details of how we will ensure a smooth transition to these new arrangements, and what interventions would be available to assist those currently operating in the market as well as to those who are looking to invest in the near term.

Decisions relating to any potential interventions we might consider will ultimately be shaped by the market arrangements we are looking to implement. For example, given zonal pricing would represent a more transformational reform than those being considered under reformed national pricing, any interventions we might consider are likely to be different and more substantive than those under reformed national pricing.

In this Autumn Update, we can confirm our commitment to treat agreements under the next CfD allocation round (AR7) in the same way as existing CfD agreements, in relation to any legacy or transitional arrangements. We also set out our expectation that if zonal pricing was to be introduced, existing and AR7 CfD contracts would be amended to use a local zonal reference price in accordance with the Principles Review process outcome under the CfD Terms and Conditions, insulating these agreements from zonal price risk.

## Our Overall Approach

As set out earlier in this document, we are keen to provide early clarity on how either zonal pricing or reformed national pricing would be designed and implemented in practice, as an important part of smoothing the transition to any new market arrangements. We are keen to engage with stakeholders on which aspects of the detailed policy design of these two options are most important to provide early clarity during any transitional period.

Going beyond this, specific additional provisions to ensure a smooth transition have been a feature of previous reforms to GB electricity market arrangements; for instance, around the introduction of the CfD scheme as part of the previous Electricity Market Reform programme.

*How were legacy and transitional arrangements treated under previous reform to GB electricity markets?*

The **New Electricity Trading Arrangements (NETA)** were introduced in England and Wales in March 2001, and later extended to Scotland in April 2005, becoming the British Electricity Trading and Transmission Arrangements. The process began in July 1998, when NETA was first considered. Over the next few years, potential contractual and legal issues arising from the reform were addressed. Additionally, new information technology systems were developed and implemented before NETA went live. The transition had a narrow focus on the practical aspects of moving away from wholesale trading via the centralised England & Wales Pool toward decentralised trading, self-dispatch, and implementing the Balancing Mechanism. By the time NETA was launched, most of the necessary changes had already been planned and executed, resulting in a very brief market transition period. The main goal of NETA was to create a more efficient and competitive electricity market in Great Britain.

**Electricity Market Reform (EMR):** The Energy Act 2013 legislated for CfD, the flagship government scheme to replace the Renewables Obligation (RO). Applications for new ROs then closed in March 2017, providing a three-year transition period. From April 2017 to March 2018, further grace periods were available for projects delayed owing to grid and other issues; as well as for projects within the dedicated biomass cap, Scottish offshore wind projects using test turbines, and other new technologies.

This question is, therefore, an integral part of our thinking within the REMA Programme, as we identify the reforms needed to make our electricity system fit for the 2030s and beyond. Any interventions for current market participants and prospective near-term investors will be focused on ensuring a smooth transition to new market arrangements established under REMA, while seeking to achieve an appropriate distribution of the benefits of any reform between generators and consumers.

Specifically, we aim to:

- Enable the continued contribution of existing market participants to a secure, decarbonising energy system;
- Minimise uncertainty for investors in potential new assets up to and during the transition;

- Ensure that our decision-making under REMA is comprehensive, taking account of the costs and benefits of any legacy or transitional arrangements; and
- Help ensure a well-functioning market by ensuring any interventions for legacy and transitional assets are compatible with the broader market reforms.

An important question as part of this is considering how far into the future any interventions might last. Stakeholders have proposed a number of different timescales for the duration of any interventions – for instance, relating to the length of existing legacy arrangements, the economic lifetime of the asset or for a particular number of years – and we need to also take into account the pace of network build and other changes which might happen while REMA reforms are being implemented. The Government is carefully considering this question to ensure that any interventions provide a proportionate and appropriate level of protection for investors.

We will assess any potential interventions aiming at achieving a smooth transition to REMA's new market arrangements against the same criteria as for elsewhere in the programme: value for money, deliverability, investor confidence, whole-system flexibility, and adaptability.

### Scheme-by-Scheme Analysis

In REMA's second consultation we committed to a scheme-by-scheme analysis of existing arrangements, to determine what interventions might be necessary for legacy arrangements and to ensure that any intervention is necessary and proportionate.

In that consultation, we defined that a legacy arrangement was a contract or set of arrangements governing participation in electricity wholesale markets agreed before a public decision on proposals made as part of REMA. These are contracts or sets of arrangements agreed in accordance with government support schemes. These schemes were established by the Government to either incentivise the development of low-carbon electricity generation or to ensure security of supply.

A legacy asset is an asset used in the generation, transmission, distribution, or supply of electricity which is the subject of a legacy arrangement at the point that REMA reforms are announced. Transition assets are those looking to invest in the period after REMA reforms have been announced and before they are implemented (for example, those bidding successfully into future CfD rounds during this period). In scope for our analysis are those assets which would still be operational at the point of reforms being introduced. However, **regardless of the reforms announced under REMA, we can confirm our commitment to treat agreements under the next CfD allocation round (AR7) in the same way as existing CfD agreements, in relation to any legacy or transitional arrangements.**

We recognise that there will be projects in the pipeline which might bid into auction rounds beyond AR7 where investors may be concerned about what the reforms might mean for their projects. This is an important consideration for our policy making. For example, grace periods might be appropriate for both zonal and reformed national pricing, so that pre-operational assets that have reached a certain level of investment maturity by a certain point in time might

also be eligible for some form of protection. How far back in time, and the level of investment maturity that projects would need to have reached in their development cycle, would require further consideration and could be dependent, for instance, on the type of asset. A longer period between decisions on our future market arrangements and their implementation might reduce the requirement for, and/or narrow the scope of, any grace periods which might be needed for particular assets or agreements – while still giving project developers sufficient time to adapt.

We have been specifically considering the impacts of REMA reform options in respect of a number of legacy arrangements, including:

- Contracts for Difference;
- The Capacity Market;
- The Renewables Obligation;
- Feed-in-Tariffs;
- The Net Zero Hydrogen Fund;
- Interconnector cap and floor arrangements; and
- Nuclear CfD and RAB mechanisms.

We are also considering government schemes currently in development, such as:

- Offshore hybrid assets;
- The planned hydrogen business models for production, transport and storage;
- Power BECCS;
- Power CCUS Dispatchable Power Agreement (DPA);
- Long Duration Electricity Storage (LDES); and
- The potential Hydrogen to Power business model.

## Functional Effects and Financial Impacts

We have been assessing legacy arrangements in two ways through considering functional effects of any reforms and, also, the financial impacts. These are defined as:

- Functional effects – contracts and schemes may rely on elements of current market arrangements to work efficiently. Should these features change, then existing contracts or schemes are likely to need to change to remain functional.
- Financial impacts – here market changes may affect, for example, asset revenue, price, volume, and level of risk.

**Functional effects:** As an example, zonal pricing, would affect what drives wholesale prices, and, therefore, the functionality of some schemes linked to these prices. As such, we are considering whether CfD contractual changes may be required to resolve functional effects

because of REMA reforms, or whether more active intervention might be required. There is a process set out in the terms of existing CfD contracts which states that the LCCC would need to bring forward amendments which are consistent with the principle of the market reference price being reflective of the price in the relevant part of Great Britain. In practice, this means that we expect the contracts to be amended to use a local zonal reference price if zonal pricing was introduced. Strike Prices would be unaffected. As a result, existing and AR7 CfD generators would receive difference payments reflective of the zone in which they were generating and be insulated from zonal price risk.

Other schemes may also require changes, and we will provide more information on these in due course. We recognise that the impacts of change will be felt differently by different market participants and these impacts may change over time. Reforms under national pricing may also have a lesser impact on scheme functionality as compared to zonal pricing.

Although our analysis is continuing, we intend to ensure any functionality issues which emerge are resolved prior to implementation.

**Financial impacts:** Even in a scenario where functional issues were resolved, further interventions may be needed to ensure a smooth transition to any new market arrangements. We are, therefore, also considering a number of potential intervention options in respect of the financial impacts of new market arrangements for legacy and transition assets under either a reformed national pricing or zonal pricing market. Zonal pricing would provide some market participants with new revenue opportunities, while for others it may represent a new risk that needs to be managed. For reformed national pricing, our lead option is a stronger and more stable TNUoS charging regime, an existing policy which market participants must already manage. The considerations will, therefore, be different under both potential scenarios.

In a scenario where we introduced zonal pricing, these potential options include:

- **Potential CfD reform:** We might consider offering a reformed CfD to existing holders of CfDs (for the remainder of their lifetime of their current CfD) as a way of helping them manage risks, but we would need to consider how this inter-relates with decisions we might want to make on CfD reform overall.
- **Development of an FTRs market:** We are potentially considering creating a market for FTRs, which could be implemented to support a zonal market. An FTR market would allow buyers and sellers of electricity to offset (i.e. hedge) potential losses related to the price risk of energy generated in one zone and purchased in another. As part of this we are considering whether or not to offer a free allocation of these FTRs to legacy and AR7 assets, such that market participants would receive a payout based on the difference in prices between two zones. We are conducting analysis on how an FTR market might be introduced, how this would compare to other financial mitigation options and the potential benefits of introducing such a mitigation.
- **Development of further mitigations:** We are currently considering further mitigations that might help existing investments manage other risks, such as volume risk, and which could be assessed on a fair, and robust, basis. Further work is required on the design,

costs, and benefits of these potential mitigations and the Government is looking to engage with industry on this work.

For reformed national pricing, GB generators already face locational investment signals via TNUoS, for which the precise values change regularly, and the methodologies have evolved over time. We would also likely need to further strengthen non-market policy measures, such as strengthening plans for centralised system and generation planning (for example, through the SSEP).

We are exploring the potential impact of all measures under consideration as part of reformed national pricing on legacy and transitional assets and considering how they are treated under such reforms. We plan to engage stakeholders further on this issue, including to inform our final decision-making under the REMA Programme.

# Chapter 3: Reforming the Contracts for Difference Scheme

## Summary

The CfD scheme is the primary government mechanism for supporting investment in large-scale renewable electricity generation. It aims to attract new investment in renewable generation by reducing counterparty and price risk, enabling developers to access lower cost of capital and, thereby, lowering the overall cost of renewable projects to the benefit of consumers.

Since its introduction in 2014, it has successfully supported a rapid increase in renewable investment, with the most recent auction (AR6) awarding 130 contracts to renewable electricity projects across GB, delivering a total capacity of 9.6GW. This is enough to power the equivalent of 11 million homes. The CfD also protects consumers from volatile gas prices as the ‘strike price’ mechanism limits the price that consumers pay during periods of high wholesale market prices. Scaling up renewables will also reduce the number of times that gas sets the market price, which further protects consumers.

Through the REMA programme, we have committed to retaining a CfD-type scheme as the primary government mechanism to support investment in large-scale renewable generation. This recognises the past success of the scheme and the continued importance of it for reaching decarbonisation targets. However, we also highlighted the need to ensure the scheme continues to meet the changing needs of our decarbonising system, with the focus on options to tackle three key challenges that the future CfD faces:

### 1) Continuing Low-Cost Growth in Investment in GB

A future, renewables-dominated, GB electricity system will likely lead to increased periods where generation supply exceeds demand. This represents an opportunity for both existing and new consumers to adjust their energy usage to take advantage of these periods of very cheap or ‘surplus’ supply. We would also expect to see a growth in batteries, green hydrogen production, and other flexible technologies which can move this ‘surplus’ supply in time to periods when it would be more valuable.

In any market, assets face the risk that they will not be paid if available supply exceeds available demand, even if they could have supplied the market. For CfD-supported assets, the likely increase in the frequency of periods of over-supply would result in increasing exposure to price and volume risk through the negative pricing rule, as assets on AR4 contracts and beyond will not get paid their CfD subsidy when any day-ahead market price periods are negative. The likelihood of not being able to dispatch due to generation surplus, illustrated by low and negative prices, is difficult to forecast with any certainty. This uncertainty has the potential to reduce overall revenue certainty for assets, increasing risk within CfD investment cases. This, in turn, is likely to be priced into CfD costs, raising strike prices and cost of capital for projects which would be passed onto consumer bills.



There may be ways for some projects to manage uncertainty around the future frequency of generation surplus, either instead of, or in addition to, increasing project cost of capital and strike price bids. For example, developers may choose to optimise asset design and performance so that more of its output is likely to be produced outside these periods of over-supply or adjust the timescales and sequence with which they bring forward individual projects across their portfolio, depending on wider wholesale market reforms. Some technologies and developers will be better able to respond to investment uncertainty than others.

### 2) System Efficient Design and Location

In shielding generators from price risk and some volume risks, the CfD blunts incentives to design projects that deliver greater system value, such as asset location and site optimisation. The current CfD, thereby, incentivises investment in projects and locations which maximise overall load factors instead of high-value output (i.e. output with a higher capture price). While we want generators to utilise GB's renewable resource (such as wind) where it is abundant, ensuring generation is responsive to demand signals is also important to lower overall system costs for consumers.

A key consideration will be the level of exposure CfD assets should have to locational signals, whether these are strengthened through zonal pricing or reformed national pricing. We are carefully considering the overall system benefits and costs of exposing renewable generators to these signals through the CfD, beyond the existing merchant tail. Chapter 1 on Wholesale Market Reform discusses generator exposure to zonal pricing signals in more detail.

### 3) Incentivising System-Optimal Asset Operation

In linking subsidy payments to metered output, the CfD incentivises generators to maximise metered output at all times of positive day-ahead wholesale prices, regardless of system need. The wholesale market will function most efficiently when generators participate based on their short run marginal cost – their cost of providing a unit of output – rather than in a way that seeks to maximise or protect subsidy payments. If they do not, this could lead to inefficiencies, perverse incentives for different technologies, and subsequent increases in system costs.

With an increasing number of CfD assets on the system, we are beginning to observe more examples of sub-optimal market behaviour. This includes distorted bidding in the Balancing Mechanism, intraday, and day-ahead markets; reduced incentives to provide ancillary services; and herding behaviours which could create potentially damaging cliff-edges in electricity supply. These behaviours result in higher system costs, which are passed on to consumers.

As CfD generation is expected to make up a larger proportion (around 70%) of the electricity market in the future, these distortions left unchecked may drive up system operation costs.<sup>9</sup> However, identifying and quantifying the possible range and scale of future system costs arising from these market distortions is inherently difficult given the complexity of predicting future behaviours of market participants. It is also possible that some of these market distortions could be reduced through other interventions without the need to reform the CfD.

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<sup>9</sup> [DESNZ: Review of Electricity Market Arrangements, Options Assessment \(March 2024\), p.27.](#)



This could include greater action outside the CfD scheme itself, for instance by the NESO, to address some of the operational distortions caused by the current CfD scheme.

As shown in the summary of responses, a majority of responses to REMA's second consultation agreed that we have correctly identified the challenges for the future of the CfD scheme. There were differing views on how far generators would be able to alter their behaviour if steps are taken to address CfD-related operational distortions. A few respondents expressed a need for further data, analysis, and modelling to understand the scale of the distortions and how generators would respond to any changes, before proposing more transformational changes to the CfD scheme.

## Updates and Next Steps

REMA's second consultation narrowed and refined the options space for CfD reform, focusing on the existing CfD structure, the capacity-based CfD, and the deemed CfD as the main options, with reference price reform and partial CfD as supplementary reform options. Since REMA's second consultation, we have engaged extensively with a range of expert industry stakeholders on these options and continue to explore the extent to which they resolve the identified challenges for CfD reform, under either a reformed national or zonal wholesale market, and at what cost to consumers. Retaining the current output-based CfD with minimal changes remains a possible outcome of the REMA process. This will continue to be the case until we can demonstrate that the consumer benefits from any reforms outweigh any increased costs, risks, and disruptions of making those changes.

Our immediate focus is to deliver the CfD reforms which are necessary to enable Clean Power by 2030. However, we also recognise the need to provide clarity on the future design of the CfD scheme and how it will interact with wider reforms across government. We can also now confirm that, if any CfD reforms are taken forward as part of REMA, any significant changes to the CfD will not be implemented until AR9 at the earliest. This gives time for industry to adjust to any new requirements and avoids disrupting any changes to the CfD scheme planned for the next allocation rounds, which are focused on delivery of 2030. For more information on shorter-term reforms to the CfD, please refer to the Clean Power 2030 Action Plan.

# Chapter 4: Transitioning Away from Unabated Gas to Low-Carbon Flexibility

## Summary

Delivering Clean Power by 2030 and an electricity system that can support a net zero economy by 2050 relies on the accelerated deployment of renewable energy. The inherently variable nature of renewables makes it critical to have sufficient flexible capacity that can ramp up or down quickly to meet peak demand and cover longer periods of low renewable production. This will require both long- and short-duration flexibility.

While forms of shorter-duration flexibility, such as batteries and consumer-led flexibility, can efficiently manage peaks and troughs in daily demand, these technologies will not be able to perform the role of long-duration flexibility<sup>10</sup> to meet demand for longer periods (days) of low wind/sun, or rarer longer periods of very low renewables output; a function currently fulfilled by unabated gas generation.

As set out in the Clean Power Action Plan, by 2030 unabated gas will account for less than 5% of total generation. While running hours will be significantly lower, it will be important to retain the unabated gas capacity needed to maintain security of electricity supply until longer-duration low-carbon flexible technologies (such as power CCUS or Hydrogen to Power) are deployed at scale.

The projected reduction in unabated gas in electricity generation, as low-carbon technologies are deployed, will effectively shift gas to a reserve role within the system. As set out in the Clean Power Action Plan, the reforms we are announcing to existing market frameworks are the best way to ensure that the necessary strategic reserve capacity of unabated gas generation remains on the system. The Government's view is that a novel out-of-the-market mechanism to manage that reserve may have a role in the long-term phase-out of unabated gas capacity once its volume in the system has significantly reduced and long-duration low-carbon flexible technologies have been deployed at scale. However, reforms to existing market arrangements are currently sufficient to ensure that strategically necessary unabated gas capacity remains available.

We will continue to monitor the deployment of low-carbon long-duration flexible technologies and associated infrastructure, and review whether our market arrangements need to evolve to manage the phase-out of unabated gas throughout the energy transition.

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<sup>10</sup> Long-duration flexible technologies include Power CCUS (Gas with Carbon Capture, Usage, and Storage), Hydrogen to Power (H2P), Long Duration Electricity Storage (LDES) such as pumped hydro storage, and unabated gas.

## Ensuring Security of Supply While Enabling the Transition to Low-Carbon Flexibility

The CM remains GB's primary mechanism for ensuring security of electricity supply and has secured the capacity we need in recent auctions.

As set out in the Clean Power 2030 Action Plan, we have proposed reforms to the CM designed to enable unabated gas to move to a back-up role while retaining the capacity we need for security of supply, by making it easier for the existing gas fleet to stay online. We are also giving investors clarity through clear decarbonisation readiness requirements, which will ensure investment in either significantly refurbished or new plants has a credible path to transition to either hydrogen or CCUS.

As the deployment of low-carbon flexible technologies continues to increase throughout the 2030s and beyond, the availability of enabling infrastructure, such as transport and storage networks, will provide routes to decarbonisation for unabated gas assets.

The Government is also examining the challenges associated with accelerating the use and deployment of short-duration flexible technologies. This involves assessing the impact of work already taking place to address these challenges across DESNZ, Ofgem, the NESO, and industry, and identifying what additional policies may be required to fully unlock the opportunities associated with short-duration flexibility. The Government is looking at the barriers faced by these technologies to fully participating in GB electricity markets across four key areas:

- Inefficient market operations;
- Barriers to market access for short-duration flexible technologies;
- Temporal signals that do not fully reflect system needs; and
- Locational signals that do not fully reflect system needs.

Some options considered within REMA wholesale market reform to sharpen locational and temporal signals or maintain system operability could have an impact on these market signals and potentially help to address the barriers listed above.

In addition, with low-carbon flexible technologies expected to play such a critical role in the coming decades, DESNZ will be publishing a Low-Carbon Flexibility Roadmap in 2025, alongside Ofgem and the NESO, outlining actions for government, Ofgem, the NESO, and industry to support both the delivery of 2030 Clean Power and 2050 net zero targets. The roadmap will bring together short- and long-duration flexibility options and enabling policies and programmes to provide a coherent and comprehensive vision for achieving the levels of flexibility required to deliver our ambitious targets. It will provide clarity and reassurance on the government's commitment to facilitating flexibility capacity growth, enabling investment from, and into, providers of flexibility. It will also remove blockers and promote coordination across government and industry.

## Ensuring Appropriate Market Arrangements

As set out in the second REMA consultation, bespoke support mechanisms may be essential for developing and building confidence in novel low-carbon flexible technologies. But as technology-specific barriers are overcome and enabling infrastructure is rolled out, there are strong arguments for transitioning back to cross-technology, price-competitive allocations at the earliest opportunity. This will harness the power of markets to identify the most cost-effective technologies and deliver best value for consumers.

Once a certain level of technology readiness and infrastructure availability has been met, the CM provides a route to supporting investment in, and the deployment, of a competitive mix of low-carbon flexible capacity by transitioning technologies away from any administratively awarded bespoke mechanisms, while offering continued revenue support.

One route to enabling this, as proposed in the second REMA consultation, could be to optimise the design of the CM auction to allow low-carbon flexible technologies access to different clearing prices by introducing minimum procurement targets (i.e. minima – an Optimised CM). We are reviewing the proposal based on the stakeholder feedback received via the second consultation and within the context of the wider REMA policy landscape, particularly a potential zonal wholesale market design. Several conditions would be needed for minima to be introduced, including that:

- The intended low-carbon flexible technologies are ready for competition without bespoke support;
- Eligible projects require and justify a clearing price above that expected across the rest of the market; and
- There is a sufficient pipeline of projects expected to participate in each auction to support a competitive auction that achieves cost-effective results.

We will ensure that any changes to the design of the CM and broader electricity market framework continue to effectively support security of supply. As set out in REMA's second consultation, we are exploring the changing nature of future stress events and evaluating the case for reforming aspects of our reliability framework. Any potential reforms would need to take into consideration potential impacts on consumer costs.

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This publication is available from: <https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rem-a-autumn-update-2024>

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