Submitted online to NESO's consultation platform

14th April 2026

NESO Reformed National Pricing Call for Input

This response is written on behalf of the Distribution Network Operators listed below. This response sets out collective views of ENA members, any of whom may also be providing their own company-specific responses to the questions contained in the Call for Input.

If you would like to discuss any of the points raised in this submission, please contact Helen.Jarva@energynetworks.org or Matt.Langham@energynetworks.org

Yours Faithfully,

Energy Networks Association

On behalf of:

1. National Grid Electricity Distribution
2. Northern Powergrid
3. SP Electricity North West
4. Scottish & Southern Electricity Networks
5. SP Energy Networks
6. UK Power Networks

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Reform Principles

Q1. Reform principles and inherent trade-offs

Do the stated balancing and dispatch reform principles identified in Section 2.2 provide a coherent and achievable framework under a national pricing, self-dispatch market design?

Please consider:

• Whether the principles conflict (e.g. transparency vs liquidity, clear handover vs flexibility).

• Which principles should take priority, or where trade-offs arise. Please provide your prioritisation of principles.

• Whether any additional principles, or changes to existing principles are required to ensure reforms support the future system needs.

ENA members agree that the principles are consistent but would like to call out the importance of the principles being set in the context of other industry reforms. ENA recommend NESO address the concerns of the distribution networks before proceeding as the current approach as-stated risks undermining local flexibility and community energy.

We thank NESO for the reassurances following the references to the SSEP, RESP and TIDE programmes but wish to raise there are still outstanding DNO concerns within each of these programmes that are yet to be addressed.

We do not support progression without a clear enduring process for whole-system co-ordination. Changes made here in a top-down way will materially impact the development of any whole-system approaches and may then preclude approaches that rely on bottom-up aggregation. We do not support a wholly-centralised approach to these reforms.

Top-down reforms applied to the whole system are only one way to solve the problems. Reforms that enable local markets such as a per-GSP or per-GSP group approach could also work. We note that several of the aims identified may pull in different directions, and careful consideration of trade-offs will be required. A particular tension exists between transparency and liquidity, in that measures that increase the visibility of positions and constrain how parties trade close to real time risk reducing the flexibility of assets and the depth of intraday markets.

There is an implicit reliance on high-quality system forecasting and ability to engage, which may not be achievable especially for smaller participants in the market.

The reforms will bring c. 7,000 distribution-connected generators into scope of the Balancing Mechanism up from c. 200 today (including accepted and connected generation.) The reforms will also potentially increase the amount of data required by a factor of six (by reducing the settlement period from 30 to five minutes.) We recognise that this may only be applied partially in retrospect but it is still a great increase over today.

The ENA recommends that NESO set out very clearly where and how these principles will be applied and the support that they will offer to facilitate change. We agree with NESO on the principles of increased visibility and dispatchability underpinning many of the highlighted reforms, however we would encourage NESO to ensure that they are suitable for a future electricity system.

Cost-benefit analyses should consider the future system. This date probably lays beyond 2050 as an asset installed today can be reasonably expected to be in service into the late 2060s and early 2070s. Ambition is

for this to be a net-zero, very distributed, very flexible energy system and these Reforms must support that. It is important that in examining options for reform to the balancing, settlement and dispatch arrangements, the flexibility technologies of the future are considered.

System security should not be compromised. NESO's proposed reforms set out how this will lead to a more-operable and more-secure system. There is an implicit reliance on communications channels and high-quality forecasting to support the implementation of these reforms. NESO needs to set out the support it will provide to anyone mandated to engage with these reforms.

Clear delineation of responsibilities between the System Operator and market participants will facilitate the co-ordinated and efficient operation of the system by allowing signals (direct e.g. dispatch or indirect e.g. pricing) to be issued and to achieve the desired outcome, without overlapping or contradictory signals causing problems. We support this as a core principle, and request input and consultation into where these lines are drawn.

Any reforms must have affordability for the consumer at their heart. When considering balancing reforms, it is important to consider the impacts of all costs that feed into the consumer bill in the cost benefit assessment of any potential changes NESO has indicated it will complete.

Q2. On a scale of 1-5, how confident are you that the balancing and dispatch reform principles set out in Section 2.2 (efficient operational signals, clear handover of balancing responsibility, secure and efficient operation of the system) are a suitable framework for reform under a national pricing, self-dispatch market design?

Scale:

1 = Not confident

5 = Very confident

3 – ENA members are somewhat confident these principles are suitable however would like to draw to the attention of NESO there is no explicit mention of DNO needs, which could conflict with NESO needs. Primacy rules (for example) must be developed and applied before confidence can be increased (noting that these are mentioned later in the RNP CfI document.)

Challenges to Address

Q3. System challenges and causal drivers. To what extent do you believe each of the challenges in defined in Section 2.3 contribute to current and future redispatch volumes and costs?

In your response, please comment on:

- Which challenges you consider structural drivers versus secondary symptoms
- Whether any challenges are over- or under-emphasised relative to the others
- Evidence from your operations, experience, knowledge of the market, and empirical or anecdotal evidence that supports alternative interpretations of redispatch growth.

Operability and cost challenge from increasing redispatch:

Structural driver caused by the transition from a top-down system to a highly-distributed system, that must be addressed in order to increase system efficiency and reduce constraint volumes. Requires structural change of the energy system.

Insufficient visibility of and access to balancing resources:

Symptomatic of a top-down system. Could be mitigated by encouraging more local system balancing actions e.g. within a GSP feeding area, or within a DNO licence area, and issuing control instructions on that basis rather than directly to thousands of DERs. Alternatively can be addressed via direct visibility and control but the data volume will be large and especially for smaller DERs the requirements may be too costly to implement.

Misalignment and overlap between the wholesale market and balancing:

Symptomatic of managing a real-time system in a less-than-real-time way which cannot be avoided but can be improved. Shorter time intervals with aligned start and end times of each mechanism involved will mitigate this, if the data flows can be set up.

Distorted wholesale price signals, and incentives to exacerbate system constraints:

Structural driver requiring reform, such that the market reflects the physical reality of the system. Unit-level trading and more-granular settlement periods will make it harder to game the system and potentially triple-dip for payments (MWh delivered to market, constraint, and dispatch to manage the constraint) within a portfolio, and this benefits everyone except the market participants who are exploiting this mechanism.

Q4. On a scale of 1-5, how impactful do you consider the operability and cost challenge from increasing redispatch to be for the GB system over the next 5-10 years?

5 – We strongly believe these challenges will be highly impactful as the system is becoming more distributed with many more market participants, which is stretching the existing redispatch and system balancing mechanisms.

Q5. On a scale of 1-5, how impactful do you consider the challenge of insufficient visibility of and access to balancing resources (particularly distributed and flexible assets) to be for secure and efficient system operation?

3 – We believe that the question of impact should be split between visibility and control rather than grouping them together, as this challenge can be addressed in multiple ways that do not necessarily require direct top-down control of DERs. The challenge of visibility and the confidence that control actions are being undertaken by someone, is more impactful than the ability for NESO to make those control actions directly.

Q6. On a scale of 1-5, how impactful do you consider the challenge of misalignment and overlap between the wholesale market and balancing (including overlapping timeframes and conflicting signals) to be for market functioning and NESO's role as residual balancer?

4 – We believe that this is impactful as the better the market performs, the less residual balancing has to be done which improves outcomes for everyone.

Q7. On a scale of 1-5, how impactful do you consider the challenge of distorted wholesale price signals and incentives to exacerbate system constraints (including opportunities for strategic positioning around congestion) to be for investment and consumer outcomes?

Scale:

1 = Low impact

5 = High impact

4 – We believe that this is impactful as wherever there is an incentive to reduce overall efficiency and increase total system cost for individual gain, this must be removed. There is also an edge-case risk that an artificial constraint will mask a real one. "System" here refers to the whole energy system and the minimisation of overall costs.

Effectiveness of the Balancing Reform Package

Q8. Impact on redispatch volumes, actions, costs: do you agree with the interactions and dependencies in the reform package defined in Section 3 to manage redispatch volumes, actions, and costs, do you see any gaps?

In your response, please comment on:

• The volume, timing, cost, and predictability of redispatch actions.

• NESO's ability to act as a residual balancer, rather than a de facto scheduler?

• Interactions with other reforms, such as P462 or other RNP reforms, that could amplify or diminish their impact on redispatch.

Please distinguish between expected impacts in the early transition period and the enduring state.

Members are of the opinion that if the reforms operate as designed, we anticipate that they will reduce the quantity of redispatch options which will reduce the operational burden on NESO, reduce the cost of balancing the system, and make constraints behave more predictably. If the market responds as anticipated to the reforms, NESO will be able to return to its role as a system balancer, rather than effectively scheduling the system at very short notice by balancing and re-balancing, sometimes against the market with associated high costs.

Q9. Market behaviour and strategic response: how do you expect market participants' behaviour to change in response to the balancing reform package defined in Section 3?

Please reflect on:

• Changes in trading, scheduling, and risk-management strategies

• Potential new optimisation, arbitrage, or strategic behaviours that could emerge

• Which design features are most important to mitigate unintended outcomes

Reforms must not encourage gaming of the system or reward the exacerbation of constraints. This includes local constraints on the Distribution network being exacerbated by management of Transmission constraints. We are reassured to see references to Primacy in the Call for Input but note that there are multiple ways to solve this problem.

Q10. Distributional and competitive impacts: What distributional impacts do you expect across different participant types and technologies as a result of the full balancing reform package implementation defined in Section 3?

Please consider:

• Impacts on generators (by technology), suppliers, storage, aggregators, DSOs, interconnectors, and consumers.

• How this change would affect your business operations (operational practices, trading strategies, and risk management).

• Whether impacts are temporary (transition-related) or structural for the market operation.

• Where targeted transitional measures may be justified, and where they could create longer-term distortions

The changes to the Balancing Mechanism threshold bring the vast majority of generating capacity in-scope and if this is to be applied retrospectively, support packages must be defined well ahead of time and the channels of support available to customers need to be well communicated. With reference to support packages for retrospective application only, this is a transitional impact.

The changes to the Balancing Mechanism will affect some new applicants for Distribution-connected generation and the requirements are more-onerous than existing requirements. This may deter small-scale renewable generation and local flexibility providers from entering the market if they are built at all, in conflict with a vision for the system that sees a place for local and community energy. Enduring support, template agreements, relaxed requirements etc. could be considered in these cases. This is an enduring impact.

DSO flexibility markets risk being undermined if reforms place unduly-onerous requirements on potential providers of flexibility. We would like to see explicit reference to DSO flexibility including document references and an impact analysis, and we cannot agree to any reforms without this and wider co-operation between NESO and DSOs being defined. If participants face higher exposure in the wholesale market, they may prioritise balancing their BM risks over offering services to DSOs. In locations where flexibility markets are still emerging, this could significantly reduce liquidity, making it harder and more expensive for DSOs to manage local constraints or mitigate outages. This becomes especially problematic as DSOs are expected to take on a greater operational role in ED3, including reducing curtailment and coordinating redispatch more actively with NESO. This is an enduring impact.

DSO members request to be consulted at an early stage on the detailed technical implementation of the proposed reforms, as any changes to data requirements will likely take at least 15 months to implement end-to-end. In particular, NESO must not assume that an ICCP link or DERMS/V&C solution will be available, and must confirm with each DSO their level of readiness for any confirmed reforms, before communicating a firm timeline to the wider base of stakeholders. This is a transitional impact.

The proposed reform package will have markedly different impacts across different participant types, and several of these distributional effects raise concerns about competitive fairness and the viability of existing market structures. Large portfolio holders – particularly those with thermal or mixed fleets – will be best placed to manage most changes, though they will face higher compliance and IT costs if PN-matching and unit-level bidding proceed, and portfolio optimisation will become harder as liquidity thins in the final hour before real time. This is an enduring impact.

Intermittent generators, particularly wind and solar, are the most sensitive to tighter PN-to-trade alignment and unit-level obligations, as their exposure to short-term forecast error is inherently higher. This is an enduring impact.

For small scale participants the reforms risk creating indirect barriers that discourage their participation altogether. Earlier locking of traded positions removes their reliance on intraday adjustments, which many smaller providers use to manage weather driven volatility or consumer behaviour uncertainty at low cost. This could lead to more unpredictable imbalance charges, which are far harder for small players to hedge. This is an enduring impact.

A material increase in the number of small distributed assets in the Balancing Mechanism, without clear primacy and co-dispatch arrangements, will substantially increase DSO operational complexity and creates a real risk of conflicting dispatch signals. Earlier trading deadlines and unit level bidding could complicate local network management, as small scale participants increasingly lock in physical positions further from real time. This reduces efficiency and reduces the DSO's ability to use flexibility as operational tools to manage constraints. The result could be more frequent curtailment of distributed generation and higher local constraint costs. This is an enduring impact.

Q11. On a scale of 1-5, how confident are you that the balancing reform package as described in Section 3 will materially improve operational efficiency and support NESO in managing the four challenges identified in Section 2.3?

Scale:

1 = Not confident

5 = Very confident

3 – for the materiality to be considered, we need to understand the cost-benefit analyses. Members have requested sight of these analyses.

Reform 1 Lower Mandatory Balancing Mechanism Threshold

Q12. Cost, benefits and implementation impacts: what implementation and ongoing costs should NESO consider associated with lowering the mandatory BM threshold reform, and what operational benefits or opportunities do you expect?

Please comment on:

• Implementation timelines and associated costs, including feasibility of phased rollout, retrospective application and target BM threshold.

• Which asset types or business models face the most material implementation and operational cost impacts, and where the reform may generate net benefits across your portfolio.

• How the reform would change your cost exposure when providing or using flexibility services

• Interactions with DSO flexibility arrangements or flexible connection agreements that may increase or decrease costs or benefits.

The cost of any retrospective application of the reduced threshold should be considered carefully and distributed equitably. This will, by design, bring many more generators and storage operators (if applied fully-retrospectively, from c. 200 to c. 7,000 based on DNO ECRs, including accepted as well as connected schemes) in-scope and particularly at the threshold the cost of compliance per megawatt on an initial and ongoing basis could be considerable, with uncertain system wide benefits.

The primary benefit cited for lowering the threshold, enhanced visibility of smaller assets, can already be achieved through existing and proposed DSO-NESO data sharing arrangements, including ICCP and control system integration, risk of conflict reporting on planned flexibility actions, and outage and curtailment visibility.

Phased roll-out should be banded by capacity, with consideration given to dispatchability as well. Non-dispatchable generation could be considered for visibility-only implementation which would simplify matters considerably and support deployment of renewables at the small scale.

1 MW could be suitable with adequate support for those in-scope and respect for DNO flexibility needs. The fallback 10 MW threshold is long-established in the SHEPD licence area which could inform a national rollout, though how the revised BM threshold interacts between Transmission and Distribution will still need to be developed if applied to the rest of the system.

Interactions with local flexibility services must be considered. If many small assets are required to join the BM without clear primacy and stacking rules, participation in DSO flexibility markets could decline or become more difficult to coordinate, creating conflicting instructions and operational uncertainty for system operators and asset owners

We highlight that there is a risk that mandatory participation in the Balancing Mechanism could stop a provider from engaging with DNO flexibility tenders either through exclusivity agreements or through onerous requirements that are functionally an exclusivity agreement. There is also a risk that, contrary to policy ambition, new local/small-scale generation does not build or even disconnects if this is applied early due to the requirements.

The overall operational value of lowering the threshold depends heavily on whether smaller assets will actually be dispatched rather than skipped during BM actions. Without a clear, evidence based case for regular utilisation, there is a risk that the additional compliance burden would outweigh any system benefits.

We request that the cost-benefit analysis showing the rationale for selecting 1 MW is made available, and that this CBA includes analyses of other options e.g. targeted measures to improve visibility of specific asset classes such as non-BM batteries through existing DSO-NESO data sharing arrangements. An alternative is to pursue enhanced NESO-DSO real time data sharing and redispatch coordination as a lower cost, lower risk alternative, alongside proportionate voluntary access routes to the BM.

Q13. Proportionality and implementation What barriers or challenges might smaller participants encounter with lowering the BM threshold? What steps could be taken to manage impacts, while ensuring the stated objectives of enhanced visibility and access are achieved?

Please comment on:

- Proportionality of compliance requirements.
- The role of aggregators or alternative access routes.
- Transitional arrangements/incentives to support parties in meeting BM obligations.
- Any specific risks to competition or market access that we should consider.

Changes to the balancing mechanism threshold are only one of a number of possible solutions available. This could for example be managed through enrolment in an existing service, or the creation of a new service; and requirements could be defined by e.g. voltage level of the Point of Connection. This may lead to efficiencies for any retrospective changes to e.g. metering and communications links, and may reduce the burden on all affected parties when it comes to developing the technical detail of how this potential reform will be carried out.

Members have commented that DSOs and aggregators could reduce the compliance burden on smaller mandated participants by providing support or assurance that an arbitrary set of smaller mandated participants can act as one or more “virtual power plants”. Particularly for the smallest affected sites, the initial and ongoing requirements and obligations for direct Balancing Mechanism entry and participation may require a disproportionate amount of financial and technical support, even if that support is made available in principle. This would not represent value for money. Allowing these sites to participate as “virtual power plants” or otherwise in-aggregate could be a practical resolution to this issue as this provides a practical means of participation for smaller assets whilst avoiding the inefficiency of requiring each device to meet BM level compliance individually.

DSOs can also continue to provide equivalent visibility for the smallest assets through existing real time data exchange channels, which already give NESO insight into DER behaviours, constraints and outages.

Financial support to implement the new threshold will help. Any funding mechanism that intends to rely on regulated companies must be developed in concert with Ofgem and we are keen to hear their views on this subject.

A critical prerequisite to any threshold change is the publication of clear primacy rules between NESO and DSOs, as without these there is a significant risk of conflicting dispatch signals and operational uncertainty for participants and system operators. Ensuring proportionality, supporting aggregation-based access, and strengthening NESO-DSO coordination and data sharing would allow NESO to achieve its stated objectives of improved visibility and access without undermining participation in local flexibility markets or placing disproportionate burdens on small DER.

A phased implementation where the threshold is stepped down in stages, the costs and benefits assessed, and lessons-learned applied, would allow the quick wins to be made sooner and the needs case for the reduction to be tested in stages – for example, it may be that reducing the threshold to 10 MW proves sufficient. As and when threshold reviews happen, we recommend a pilot approach for a small number of affected DERs before any broader threshold reduction, allowing evidence-based assessment of costs and benefits and ample time for issues to be identified and addressed.

Q14. On a scale of 1-5, how confident are you that lowering the mandatory BM participation threshold will significantly improve visibility and access to balancing resources, while remaining proportionate in terms of costs and obligations?

Scale:

1 = Not confident

5 = Very confident

2 – low confidence. If applied retrospectively, the costs and requirements could very well outweigh the benefits. Members consider that the requirements for visibility-only will be lower than those for visibility and control and therefore more proportionate to the costs and obligations.

Reform 2 Aligning Market Trading Deadline with Gate Closure

Q15. Risk allocation and market functioning: how would aligning the market trading deadline with gate closure reallocate forecast, imbalance, and operational risk between market participants and NESO?

Please consider:

- Impacts on trading liquidity and intraday risk management.
- Current use of post-gate-closure trading.
- Effects on different technologies and business models.
- Whether the reform strengthens or weakens the clarity of balancing responsibility.

We are of the opinion that this reform will slightly increase sensitivity to rapidly-developing price shocks on the wholesale market e.g. the sub-hourly spot price swings in oil and gas caused by the current Israel/USA-Iran war. This may slightly increase electricity costs overall as generators exposed to that risk will price that risk into their models. However, with the transition to a net-zero energy system this effect will only be present for a short amount of time.

This reform rolls back a change made in 2017 when the amount of intermittent generation on the system was much reduced compared to today, and these new generators have been able to make trades to reflect changing conditions post-gate closure due to changing forecasts. This will be a fundamental change for them. This reform acknowledges that intermittent generators will need to improve their within-day forecasting and this is a common implicit theme throughout this Call for Input, that forecasting will improve and keep improving as time goes on. It will never be perfect, and definitions of “best estimate”, “best forecast” and the like must consider this.

The burden of compliance for the real-time flexibility market to participate must be low, which possibly conflicts with reducing the threshold for Balancing Mechanism participation.

NESO will have a clearer balancing responsibility and in theory longer to carry out these responsibilities, which should reduce the burden of balancing the system and give more confidence that balancing actions undertaken will not be undone and require rework.

Q16. Implementation timelines, costs and transition considerations: what implementation and ongoing costs should NESO consider associated with aligning the market trading deadline with gate closure?

Please comment on:

- Implementation timelines and costs of adapting trading systems and internal processes to an earlier deadline.
- Cross border or contractual factors that may increase cost or extend implementation timelines.
- Any ongoing cost implications of the change.

We anticipate that the direct cost impact of this alignment on DSOs will be limited but that there is potential for the reforms to drive up the cost of Distribution flexibility more generally.

Q17. On a scale of 1-5, how confident are you that aligning the market trading deadline with Gate Closure will improve clarity of balancing responsibility and reduce inefficient overlap between market trading and NESO balancing actions?

Scale:

1 = Not confident

5 = Very confident

4 – we are confident that this reform will achieve greater separation of market trading actions and balancing actions.

Reform 3 Physical Notifications Matching Traded Positions

Q18. Costs, benefits and implementation feasibility of FPN to match traded positions: what implementation and ongoing costs should NESO consider associated with implementing FPNs to match traded positions?

Please comment on:

• Implementation and ongoing costs, including system changes, forecasting processes, and compliance requirements.

• Differences in cost and implementation timelines between portfolio level and unit level approaches.

• How differing technologies within a portfolio may affect the complexity, cost, and practicality of implementing the reform.

We do not anticipate any major changes to direct DSO costs and to DSO systems.

Q19. Risks, tolerances and exemptions: what risks or unintended consequences could arise from the different scenarios proposed for FPN to match traded positions under portfolio bidding or unit bidding, and how should tolerances or exemptions be designed?

Please comment on:

• Technology-specific and contract structure differences.

• Potential gaming or risk-shifting behaviours.

• Governance and enforcement considerations during transition.

• Whether obligations should differ between aggregated portfolios and disaggregated unit-level positions.

No DSO comment – flexibility providers are better-placed to input. DSO forecasting such that flexibility can be accurately called upon (which will therefore enable the flexibility providers to meet their own obligations) is an area of active development, and with suitable forecasting tolerances designed into the system we do not anticipate issues.

Q20. On a scale of 1-5, how confident are you that requiring FPN to match traded positions will improve forecasting accuracy, transparency, and NESO's operational confidence, without creating disproportionate implementation or compliance risks?

Scale:

1 = Not confident

5 = Very confident

3 – thresholds need to be defined and the cost-benefit analysis clearly communicated before we can comment.

Reform 4 Unit Level Bidding

Q21. Value of unit-level granularity: what benefits and risks do you associate with introducing unit-level bidding and nominations in the wholesale market, including the potential requirement to submit these at Day-Ahead and Intra-Day stages?

Please address and specify when referring to Option 1 or Option 2:

• How this change could support alignment between physical notifications and final traded positions.

• Impacts on visibility pre-gate closure, market monitoring, and deterrence of inefficient, strategic behaviours.

• Potential effects on liquidity, price formation, and participant risk exposure.

• Differences between physical (Option 1) and financial (Option 2) approaches, including operational complexity and portfolio aggregation challenge (e.g. breaking down aggregated positions into individual unit bids, managing compliance across diverse assets).

This change should support alignment between physical notifications and traded positions by compelling portfolio operators to set their positions per-unit, rather than aggregated across their portfolio (and therefore across constraint boundaries.) This reform has the potential to act to stop market participants from gaming constraint payments, which is supported by members.

For smaller providers, who may only have one or a few units, this will not make a practical difference. For portfolio operators with many units this may have unforeseen or underestimated impacts and a transitional period is recommended, that covers both winter peak and summer minimum. This will allow for any unforeseen, unintended or undesirable outcomes to be identified and addressed before general deployment.

Q22. Cost, proportionate granularity and implementation timelines: what implementation and ongoing costs should NESO consider associated with implementing unit level bidding? What level of unit granularity would be practical and proportionate to deliver meaningful system benefits?

Please address and specify when referring to Option 1 or Option 2:

• Implementation and ongoing costs, including IT, data, and compliance requirements associated with different unit-level approaches.

• Practicality and proportionality of different levels of granularity (the extent to which positions are broken down purely to BMU level or aggregated by GSP group), and where the balance lies between system value and implementation burden.

• Implementation timelines and key dependencies, including interactions with cross-border market coupling and the provision of ancillary services.

We consider the GSP group level a natural and suitable level of granularity for the design of this reform if it goes ahead, with processes and tools already able to support it. Any transitional arrangement should cover at least a year to allow for a full range of conditions to be tested-for and addressed. In the rare case that a change in running arrangement moves a market participant from one GSP group to another this change can be handled on a bespoke basis.

Q23. On a scale of 1-5, how confident are you that unit-level bidding (option 1 physical) will materially enhance transparency, scheduling, and market monitoring, relative to its complexity and transition costs?

3 – we need to see a detailed plan before we can comment on any relative materiality.

Q24. On a scale of 1-5, how confident are you that unit-level bidding (option 2 financial) will materially enhance transparency, scheduling, and market monitoring, relative to its complexity and transition costs?

Scale:

1 = Not confident

5 = Very confident

3 – we need to see a detailed plan before we can comment on any relative materiality.

Reform 5 Shorter Settlement Period

Q25. Temporal efficiency and system outcomes: how effective would shorter SPs (e.g., 5 or 15 minutes) be in addressing temporal inefficiency, imbalance volatility, and the use of fast-acting flexibility?

Please consider:

• Whether settlement granularity should move in step with other market timelines (e.g. gate closure, trading deadlines)

• Operational and commercial impacts on your organisation

• Interactions with imbalance pricing and balancing actions

• Which market participant cohorts would benefit most from shorter SPs, and how could this inform staged implementation?

The question is slightly unclear with two views presented by members – if the interpretation of "timeline" is of implementation, moving in step with other change timelines is logical. If the interpretation of "timeline" is of reducing every time-based aspect of the market in proportion with the settlement period, this probably warrants an entire programme of work in and of itself.

A concern is that the volume of data to be generated, stored, and exchanged will be considerably more than under the 30-minute regime, which must be considered at an early stage and would probably benefit from a specific request for technical information from all stakeholders to understand existing capabilities and limitations.

The natural beneficiaries are stakeholders who have highly-dispatchable DERs, representative examples being batteries and highly-flexible loads who already have an agreement in place. These would be ideal candidates for any testing of shorter-term price signalling and settlement.

Q26. Cost, deliverability and implementation timelines for shorter SPs: what are the principal implementation and ongoing cost drivers in delivering shorter settlement periods (5 or 15 minutes), and how can these be mitigated to ensure a smooth transition?

Please comment on, identifying any differences between 5 and 15 minutes:

• Implementation and ongoing cost drivers, including system upgrades, metering changes, data and forecasting requirements, and impacts on internal operational processes.

• Practical and logistical challenges of metering upgrades or installations, and supplier system readiness.

• Implementation timelines and feasibility of phased vs. single step migration, including key dependencies (e.g. digitalisation progress, readiness of trading and settlement systems, metering upgrades).

• Transitional arrangements—such as shadow settlement or staged go live—that could support a stable migration.

Members have raised the concern that historically, changes to metering and settlement (Smart Meter rollout, MHHS) have taken longer and been more challenging than first anticipated. In order to execute this change smoothly, the complexity of this task must be appreciated from the outset, all stakeholders must be brought

along from the outset, and a phased programme of work is strongly recommended. A trial period of logging data at shorter intervals but still settling half-hourly could ease the transition.

Data systems will have to deal with up to 6x more data from each participant, even before the number of participants increasing potentially by 35x is factored in, and with the settlement window shortening, timeliness of transmission of data becomes more-important. Readiness to implement this, and requirements for doing so, should be the subject of a specific request for information from affected parties.

Q27. On a scale of 1-5, how confident are you that shorter SPs (e.g. 5 or 15 minutes) will materially improve temporal efficiency and use of fast-acting flexibility, given current and planned system, data, and metering capabilities?

Scale:

1 = Not confident

5 = Very confident

4 – with the right flexibility markets – including DSO markets – and the right commercial signals in place members are confident that material improvement could be seen. This is reliant on the wider context that this potential reform operates within.

Reform Package Cost-Benefit Analysis and Evaluation Framework

Q28. To what extent do you agree with the proposed CBA methodology and evaluation framework, and are there additional factors NESO should consider?

Please focus your response on:

• Whether you agree with the overall CBA approach and methodology, and whether any important factors are missing.

• Expected operational or market behaviour impacts (e.g. forecasting, trading strategies, operational planning) that should be reflected in the CBA.

• Key risks or uncertainties (e.g., liquidity impacts, forecasting uncertainty, operational risks) that should be captured in sensitivity analysis.

• How your organisation typically estimates implementation costs (e.g. CAPEX vs OPEX, system upgrade cycles), and any practical challenges in providing robust cost estimates for the balancing reform package.

• Any distributional or competition impacts that should be included to distinguish system wide benefits from simple cost transfers.

• Which post implementation metrics or indicators would be most meaningful to assess success.

There is a risk that top-down flexibility and mandatory Balancing Mechanism participation could undermine DSO efforts and community energy plans to participate in flexibility markets. At present, flexibility is used to manage physical constraints on the network, with limited interplay between Transmission and Distribution. System balancing and constraint management at any and all system levels are two separate issues (we note that this is clearly communicated in the RNP CfI) and there is potential for opposition between solutions. In the worst case, top-down flexibility and mandatory Balancing Mechanism participation could act to worsen local issues and create greater conflict of needs across system levels.

High-quality forecasting is a requirement of the proposed reforms. Support must be given to the smaller participants, who may struggle to develop the capability required by themselves.

It is possible and practical to set the Balancing Mechanism threshold by connection voltage rather than capacity, e.g. in a manner similar to Engineering Recommendation G99 whereby a 132 kV-connected site is automatically Type D regardless of installed capacity.

We need to see more detail in the plans before we can comment in detail on this, and would welcome being directly engaged in the inputs to and methodology of the cost-benefit analysis.

Reform Package Implementation Roadmap

Q29. To what extent do you agree with the proposed approach to developing the implementation roadmap, and what practical considerations should NESO take into account?

In your response, please comment on:

• Whether you agree with the overall approach to sequencing and phasing reforms, and whether any important elements are missing.

• Practical insights on implementation timelines and organisational readiness, including internal lead times, required system changes, and interactions with other industry programmes.

• Key dependencies and risks NESO should account for (e.g. digitalisation constraints, system readiness, regulatory interactions, potential bottlenecks across the current market change pipeline).

• Transitional arrangements that may ease implementation, such as phased migration, shadow operation, or alternative access routes for smaller participants.

• Any evidence or experience (e.g. data availability, expected operational impacts, lessons from previous programmes) that would materially improve the practicality or proportionality of the roadmap.

We need to see a roadmap in detail before we can consider agreement or disagreement.

We note that there are industry-wide efforts to modernise and digitalise processes and move them to common platforms; these are still in active development. We are supportive of a transitional period where reforms are made as systems become ready to enable them, provided that there are clear feedback mechanisms before, during, and after implementation of each reform.

We are awaiting publication of a piece from DESNZ on the topic, and this may influence our responses. If so, we will follow up on our initial response to this call for input.

Dispatch Reform

For all the following questions refer to Section 5.

Q30. Objectives and Design Principles: what should be the primary objectives and guiding principles for investigating any future dispatch reform in the GB electricity market?

Please address:

• How dispatch reform could improve system efficiency, transparency, and cost effectiveness.

• The role of market signals versus centralised instructions in achieving these objectives.

• Key considerations for maintaining competition and liquidity under new dispatch arrangements.

The guiding principle should be to develop and maintain an efficient system at all voltage levels without compromising resilience. Any solution must be proportionate to the cost and complexity and must not undermine competition, value-stacking, etc..

We need to understand the technical detail of how this aspect of the RNP programme will work before we can comment fully. We are interested in the mechanisms and implementation of dispatch reform, any new standards to be adopted e.g. new APIs, and how the responses to dispatch instructions will be measured.

Q31. Market and Operational Impacts: what impacts—positive or negative—could dispatch reform have on market participants and system operation?

Please comment on:

• Dynamics and interactions between market participants and system operation, as illustrated in the diagrams.

• Effects on trading strategies, risk management, and portfolio optimisation.

• Implications for different participant types (generators, suppliers, aggregators, storage, DSOs, interconnectors).

• Potential interactions with other reforms (e.g., unit bidding, shorter SPs).

• Implementation and ongoing cost implications, including system upgrades, process changes, and operational readiness for participants.

Dispatch reform must consider collaboration between DSOs and NESO and dispatch reforms must not interfere with a market participant's ability to participate in Distribution-level flexibility nor interfere with a DSO's ability to manage and operate their own network. An overall system with fewer constraints and more local consumption of electricity is more resilient and is cheaper to both construct and operate, and the benefits of this must be assigned in proportion to the outlay of effort by each system user. A collaborative approach that does not rely on a wholly-centralised system will likely unlock the greatest whole-system benefits.

Q32. Implementation Pathways and Risks: what implementation pathways and risk mitigations should NESO consider for dispatch reform?

Please address:

• Feasibility of phased or incremental approaches.

• Data, system, and governance requirements.

• Transitional arrangements to minimize disruption and ensure proportionality.

• Potential implementation timelines and associated costs, including required system changes and operational readiness.

We need to see a detailed technical implementation plan to comment fully.

A phased approach for any reform is supported, throughout a transitional period as reforms are implemented and then tested to ensure they operate as designed. This may happen in parallel with other reforms.

The costs must be clearly defined and agreed between all affected parties before work commences.

We consider that a minimum of 15 months from kick-off will be required, noting that this piece of work will be happening in parallel with other changes and that there will be some degree of enabling work happening in the background, if we remain co-ordinated as an industry. Without this implicit co-ordination, timelines could be significantly longer.

Q33. On a scale of 1-5, do you agree that further dispatch reform on top of the proposed balancing reforms will be needed to meet the future operability and redispatch cost challenges described in Section 2.3 and Section 5?

Scale:

1 = Strongly disagree

5 = Strongly agree

3 – too early to say either way.

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