Learning together

A joint consultation on proposals for local flexibility

nationalgrid DSO | DSO | UK Power Networks Delivering your electricity

Contents

1. Why we developed this document

Local flexibility is a critical tool for managing the cost of distribution networks and accelerating connection of low carbon technologies, particularly in the context of the UK's Net Zero commitments. It allows network operators to keep connecting new customers and assets, ahead of the need to upgrade the network.

In 23/24 UK Power Networks and National Grid Electricity Distribution (NGED) tendered for over 680MW of flexibility services and dispatched over 10GWh of flexible generation, storage and demand. This constituted nearly 90% of all DSO flexibility.

Since 2017, volumes of need and use have grown, with further growth expected over the next five years of our price control, known as ED2. Both organisations have worked closely with customers to innovate and support this growth, positioning Great Britain among the leaders in using local flexibility.

However, we continue to see opportunities for service provision unmet, and limited competition across a number of our requirements.

In 2023/24, more than half of service needs were unmet across the organisations. As such there is a clear requirement to continue to drive improvement in how we procure services. We are striving to build liquid and competitive markets at a local level to maximise the benefits we can release.

Through the Open Networks programme we are using our real-world experience to play significant roles in simplifying and standardising the approach to local flexibility across the industry. We firmly believe that cross-DSO and DSO-ESO alignment is fundamental to the growth of local flexibility – a position reinforced regularly by many of our flexibility providers.

Our efforts are having real impact already, for example through newly aligned registration requirements which standardise the questions asked by all DSOs.

Nonetheless, we believe there is opportunity for further learning and alignment, and that it is our responsibility as leaders to facilitate this. We intend for this paper, and the industry feedback that it generates, to inform short-term actions across our organisations and to feed into the direction of Open Networks and the new Market Facilitator.

We have selected areas of focus where we believe we can learn from one another and where a more consistent approach would have considerable value.

In many cases National Grid Electricity Distribution and UK Power Networks have a similar view of the way forward and we are putting forward a single approach for feedback.

In others, we have outlined different options, and will closely review stakeholder feedback to determine whether there is a 'best' approach which can be consistently adopted.

We believe alignment is fundamental to enabling the growth in liquidity assumed within our ED2 Business Plans. This is not an argument against innovation, but towards targeting that innovation in the areas of greatest uncertainty and aiming for standardisation and simplification elsewhere.

We hope that by communicating together, stakeholders find these proposals easier to digest and offer constructive feedback.
We welcome views on this approach.

The consultation document will be accompanied by an online workshop on 22nd July.

To respond, please submit feedback via **Slido** or by contacting both organisations (**nged.flexiblepower@nationalgrid.co.uk** and **flexibility@ukpowernetworks.co.uk**) by 23rd August 2024.

Please be aware that we will share responses between the two organisations unless explicitly informed otherwise. We will provide a summary of responses and next steps in the Autumn.

Thank you for engaging on the future of local flexibility.

2. Moving to consistent timelines for procurement and dispatch

Definitions

Contract
The point where contractual terms are agreed, this might occur after a provider is successful in a specific procurement event or a framework contract that covers ongoing procurement events.

Award/Trade
The point where a provider has had a specific offer accepted by the DSO, committing to time windows, volume, and price. Some DSOs might have post award mechanisms to vary some of these commitments such as timing and volume.

Utilisation/Dispatch Request
For services which rely on a call-off mechanism, this is the point where the DSO confirms its actual needs (usually closer to operational timescales).

The importance of consistent timelines for procurement and dispatch

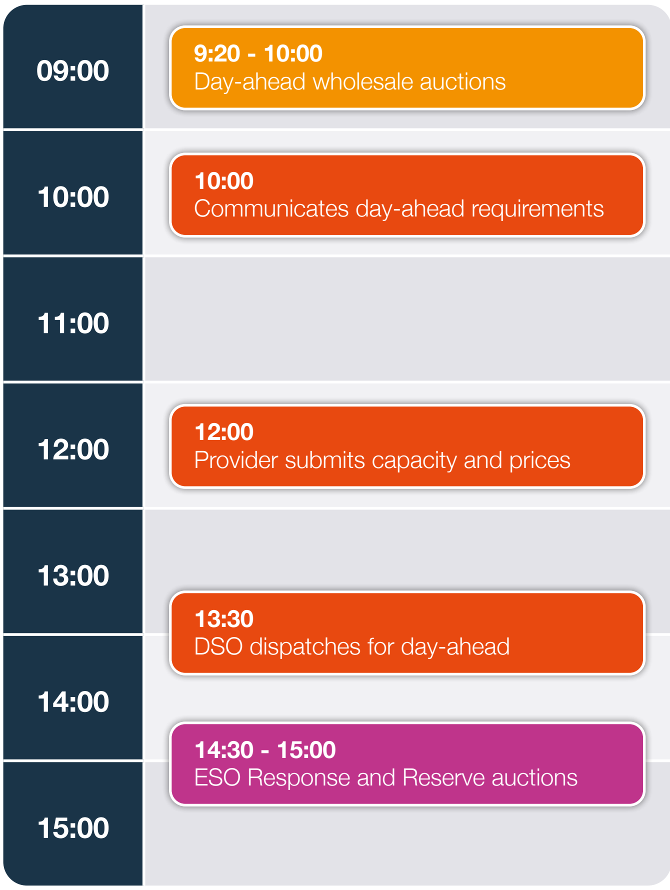
Applying consistent timelines for procurement and dispatch can facilitate simpler processes and system requirements for participation.

Critically, they also simplify potential interactions between services (particularly those procured by ESO and DSO), enabling clearer and more open stacking rules and ultimately increased opportunities for flexible resources.

The Open Networks project recently published an updated set of five products and twelve product variants. These provide a more detailed definition of DSO products and will drive improved coordination. For example, these products set clear timelines for 'operational dispatch' (where procurement and dispatch decisions are made at different times) – with options to instruct 2 or 15 minutes before delivery.

Some timelines such as "at procurement", "day ahead "and "week ahead" could drive differing interpretations. For example, day ahead utilisation could fall at different times.

We want to explore some of the details of these timings, and seek views on how to use them optimally.



2. Moving to consistent timelines for procurement and dispatch

Our experience to date

Historically DSO flexibility procurements have focussed on longer term contracts months or years ahead of need. Where sufficient flexibility has been sourced, this has allowed network upgrades to be deferred while new customers or assets continue to connect to the network. Where sufficient flexibility has not been available at an economic rate, this has allowed sufficient time for alternative solutions to be put in place. These long-term contracts have also supported the investment case for new assets or start-up flexibility providers. This approach has supported the growth of DSO flexibility markets to date.

The timing of dispatch decisions has varied across networks and products – in some cases it has been set at the point of contracting, some at week ahead and some made minutes before delivery.

The need for longer term contracts will remain until highly liquid shorter-term markets are in place. They are needed to provide the DSO with confidence that network risk can be managed and investment deferred.

However, both organisations have received feedback that moving commitment decisions closer to real-time would enable greater participation – particularly from demand-side assets (where availability is often uncertain a long time in advance) and assets which are looking to optimise their participation across multiple markets (where the opportunity costs of committing to the DSO are unclear a long time in advance). That said, leaving the commitment too late, such as beyond gate closure in the balancing mechanism, can make revenues stacking more difficult.

As such DSOs need to balance the requirement to retain longer term markets whilst building out shorter term ones.

In 2023, UK Power Networks moved its dispatch decisions to 2pm day-ahead, to provide greater clarity to flexibility providers about their ability to participate in ESO markets.

Following trials, UK Power Networks expanded the coverage of its day-ahead market in April 2024. This approach is founded on advancements in its short-term forecasting of network constraints - which allow it to pinpoint flexibility requirements for the following day.

National Grid Electricity Distribution currently operates week ahead short-term markets, that sit alongside longer-term procurements across its zones. National Grid Electricity Distribution trialed day-ahead decision-making through its IntraFlex innovation project, which highlighted the market potential for closer to real time procurement, alongside long term procurements.

While moving award and dispatch decisions to day-ahead offers potential value, it is clear from our experience that there could also be considerable per-transaction costs and efficient systems must be in place to (largely) automate decision-making for both DSO and flexibility providers.

Another challenge facing short-term markets is uncertainty in utilisation requirements. Typically a DSO will be conservative in planning timescales, with flexibility requirements reduced closer to real-time when uncertainty is less.

The availability of the short-term market, which has value for the DSO, is not well shared, potentially making such markets unappealing – particularly if there are one-off costs to participation.

To manage this risk, in its initial short-term procurements UK Power Networks provided 10 hours of guaranteed utilization volumes.

2. Moving to consistent timelines for procurement and dispatch

Our proposed way forward

We both continue to see significant value in longer term tenders, particularly in providing sufficient confidence of flexibility availability to make decisions to defer network investment.

Relying on short-term markets cannot yet provide this same confidence. We therefore expect to run both long-term and short-term processes for the foreseeable future.

We intend to publish our full flexibility requirements and contract for some or all of them within long-term markets. Short-term markets will enable additional providers to participate and provide additional competition for utilisation prices. We see value in aligning dispatch timings for long and short-term products to promote competition between the two.

We believe that long-term tenders should be complemented with short-term processes for day-ahead award and dispatch, early enough to allow participation in ESO's auctions for Frequency Response and (in the future) Reserve services. This would imply a deadline for communication of decisions of around 2pm day-ahead. We propose 1.30pm.

When procuring at day-ahead we believe that there is limited value in separating out availability and utilisation decisions, and that we would conduct utilisation-only competitions, where the result of the auction would include the dispatch instruction.

How quickly these changes are introduced will depend on the balance of value to any enabling investment in systems, processes and personnel. UK Power Networks started to roll out day-ahead procurement across its network from April 2024.

National Grid Electricity Distribution currently expects to conclude the move of its trade and dispatch decisions from week-ahead to day-ahead in 2025.

In the minority of cases, where we are using flexibility in response to an unplanned fault, there would still be a need for closer to real-time dispatch. Current use cases have focused on de-loading networks to enable enhanced customer restoration.

This has asked Flexibility Service Providers (FSPs) to respond in 15 minutes. The new ENA products support 2 minute responses, which could reduce restoration times, and could even allow for post-fault actions against faults that fall within network security of supply standards.

To help ensure value in short term markets, we are considering the use of minimum utilization volumes in short term markets. These would be per zone, rather than per provider, and set relative to the value of the zone.

Questions

1. Do you agree with the approach of aligning decisions on short-term awards/trades and dispatch at day-ahead? If so – would a decision by 1:30pm support your operational and commercial processes?

2. What do you see as the biggest costs or challenges of participating at day-ahead and what enablers would you expect to be in place?

3. Would your assets be able to respond within 2 minutes? Is an alternative commercial structure required to enable this?

3. Deployment of 'Demand Turn Up/Generation Turn Down' services

Definitions

Demand Turn Up (DTU)
A service where customers increase their demand. For example they might charge their EVs or move consumption to the relevant time period.

Generation Turn Down (GTD)
A service where customers decrease their Generation. They could simply turn off a generator.

Demand Turn Down (DTD)
A service where customers decrease their demand. For example they might avoid charging their EVs or move consumption away from the relevant time period.

Generation Turn Up (GTU)
A service where customers increase their generation. They could simply turn on a generator.

ABSVD: Applicable Balancing Services Volume Data.
This process adjusts settlement data to account for the provision of applicable balancing services. This avoids suppliers being penalised for the provision of service.

The importance of Demand Turn Up/Generation Turn Down services

To date, DSOs have predominantly procured flexibility to reduce network demand, hence procuring Demand Turn Down (DTD) or Generation Turn Up (GTU).

The business case for DSOs to do so within their regulatory settlement is clear. If flexibility can help defer load-driven reinforcement costs within the plan, then any savings are shared between the DSO and consumers. This value case remains and will continue to grow with the adoption of more electric vehicles and heat pumps.

However, there is a growing number of areas with capacity needs driven by high levels of generation. Historically most of the reinforcement costs were paid for by the connecting generators rather than the DNO.

As such DNOs introduced flexible connections as a means for customers to obtain quicker and cheaper connection by accepting curtailment.

In April 2023 Ofgem changed the connection charging regime so that DNOs now take on a lot more of these costs. Flexible connections are still available to customers, but many now come with guaranteed limits on curtailment and end dates.

This has created a much simpler benefits case for the DSOs in valuing DTU/GTD services.

These can be used to either defer the reinforcement triggered to deliver the end date, or be used to manage the risk of curtailment exceedance payments.

3. Deployment of 'Demand Turn Up/Generation Turn Down' services

Our experience to date

Both DSOs see real value in this new use case. National Grid Electricity Distribution trialled DTU back in 2016 to understand the feasibility of such services, however roll out was limited due to issues around the value case, the challenges on aligning to connections led timescales and the co-location of flexible assets with the areas of need.

The market has moved on significantly since then. The new charging regime creates new value streams, however due to the lag between offering connections, and them connecting, needs in the near term are limited. National Grid Electricity Distribution will be opening new DTU zones in its Autumn procurement.

UK Power Networks launched DTU services in the Winter 2022 tender in response to the anticipated changes to network charging.

The first units were dispatched from Summer 2023, including wind, solar, residential demand and EV charging.

Around 4GWh has been dispatched and more volume continues to be on-boarded. The response from the market has been positive, including over 24,000 households registering onto the service via Octopus Energy's PowerUps scheme.

UK Power Networks makes dispatch decisions for DTU/GTD at day-ahead. When a need is forecasted, the provider is notified in the morning, providers submit their capability and price by midday and if required a dispatch is issued at 2pm day-ahead.

The service has opened up local flexibility to a wider set of technologies and business models. There are also new stakeholders too, such as off-takers that need to be comfortable to sign-off on the potential for lower generation volumes.

UK Power Networks has observed higher flexibility potential from domestic assets to turn up demand (compared to turning down).

3. Deployment of 'Demand Turn Up/Generation Turn Down' services

Our proposed way forward

There is clearly strong market appetite for DTU/GTD services, which can now be a useful tool for managing generation-driven constraints, particularly in shorter term procurement.

The challenge is now to scale up the interactions to provide enduring value to both DSOs and FSPs.

There is a need to review the flexibility procurement process and products to ensure that they remain attractive to the market whilst also aligning with the needs of the connections process such that the most economic and efficient decision can be made amongst the combination of flexible connections, flexibility procurement, and network reinforcement.

This could include pairing them with longer-term contracts to support network investment decisions.

Questions have also been raised around risks to off-takers, and how to manage them appropriately. In the Intraflex project, National Grid Electricity Distribution looked into this topic for DTD/GTU services, and identified potential mitigations through information provision or the extension of the ABSVD process.

However, this was not progressed due to the limited value to the market. This may need to be reconsidered following market growth and this new use case.

Questions

4. Would longer term DTU/GTD contract, with greater commitment to be available, be attractive to you?

5. How can we best manage the impact of DTU/GTD services on supplier or off-taker imbalance positions? For example through earlier dispatch decisions, better forecast data, or extension of the ABSVD process.

4. The value of fixed baselines

Definitions

A fixed baseline
Is known at the point of contract and does not change. It may be set according to the measured behaviour of the asset prior to the contract, or according to behaviour of some 'reference class' (e.g. a sample of Electric Vehicles that are not smart charging).

A provider-nominated baseline
Is one submitted by the flexibility provider on a regular basis as an accurate forecast of their consumption or generation in the absence of a flexibility dispatch. This is the approach used within the Balancing Mechanism.

A recent history baseline
Is calculated based on behaviour during some recent comparable time periods – for example the baseline for 17:00-17:30 on Monday might be an average of behaviour at the same time over the past 10 weekdays, excluding any days where flexibility was dispatched. An extreme example of the recent history baseline is the 'immediately prior' baseline which uses the reading immediately prior to a dispatch event.

Why are baselines important?

Baselines represent what would (or could) have happened if flexibility had not been procured.

They are used by buyers of flexibility to determine whether they have received the service they procured and have a material impact on how much flexibility a given asset can offer and the amount it is ultimately paid.

The complexity around baselines, and how they influence the flexible capacity that can be offered, can sometimes be a barrier to participation and a source of frustration to those already participating whose payments may be reduced in line with their baseline behaviour.

While baselines may seem a technicality, their impact on flexibility is profound.

4. The value of fixed baselines

Our experience to date

Open Networks has previously identified four equal principles for baselines.

Simplicity
The baseline should be practical and the effort required proportionate to the outcome.

Accuracy
The baseline methodology provides a good representation of the counterfactual behaviour.

Integrity
Restrict the ability for the DER provider to distort or game the market.

Replicability
Can be replicated for forecasting and verification to all relevant parties.

Engagement with FSPs, and National Grid Electricity Distribution's recent **report on revenue stacking** have highlighted that the choice of baseline can also have a significant impact on the competitiveness of a given technology type and the ability to stack different services, where delivery of Service A may affect the baseline for Service B.

UK Power Networks has typically provided a 'menu' of baseline options for each product or technology type and where providers are not satisfied with the proposed options, they have been able to make alternative proposals.

This approach has helped to grow participation and provided broad experience of the effect of different approaches, but risks becoming unwieldy and inadvertently favouring a particular technology or provider.

In general, services which are dispatched at day-ahead have used a recent history baseline, while services which deliver an enduring reduction in peak demand (e.g. domestic EVs or energy efficiency) participate with reference to a fixed baseline. Some renewable assets have chosen to use a nomination baseline – particularly where they are already required to provide similar baselines for the Balancing Mechanism.

UK Power Networks' recent history baseline has been shown to be one of the most accurate baselines available (i.e. the best predictor of what an asset does in the absence of a dispatch instruction).

However, in some cases it has failed to reward generation assets which have reliably generated when requested, but which the baseline has judged as 'likely to have generated anyway'.

Initially National Grid Electricity Distribution employed recent history baselines. However, this presented challenges for newly connected assets, portfolios with changing assets or assets that were active in many markets.

The requirement for "clean" metering data to support baselining acted as a barrier to entry. As such a number of options emerged, such as zero baselines for generation.

To simplify the process National Grid Electricity Distribution now applies fixed baselines, aligned to the assumptions used in the network planning phase as this is when most of the flexibility is procured. These load profiles are taken from measured data, academic studies, and innovation projects, and are known as the customer behaviour assumptions.

For generation and storage assets, planning assumptions are quite conservative – within a demand-constrained zone, storage may be importing at 100% and generation sitting idle.

Using these profiles means that each unit of flexibility procured is against the planning counter-factual which indicated a need for additional capacity.

4. The value of fixed baselines

Key similarities and differences in current approaches

	UK Power Networks	National Grid Electricity Distribution
Dispatched weeks or months ahead of time	Fixed (for domestic EVs or anything with 1 yr historic data)	Fixed baseline except I&C demand
Dispatched day-ahead or closer to real-time	Recent history, Nomination, Fixed (EVs)	Fixed baseline except I&C demand
Baselines for commercial demand	Recent history	Self nominated based on recent history baseline
Baselines for generation and storage	Recent history/Nomination	Fixed baseline (worst case)
Choice of baseline	Provider selects at contracting stage	Determined by service and technology type

Summary of issues identified

- Approaches are not consistent across DSOs.
- The perceived and actual complexity of baselines is inhibiting service participation.
- In some cases, baselines are preventing service stacking.
- System operators and flexibility providers are expending considerable time to manage baselines. This is likely to increase if recent history baselines need to be adjusted for actions by other system operators.
- Flexibility providers cannot easily or reliably predict their 'recent history' baselines – creating uncertainty on what capacity they have available and how much they will be paid.

4. The value of fixed baselines

Our proposed way forward

It is clear that trade offs will need to be made between the Open Networks principles. Our experience to date has highlighted the particular tension between Simplicity and Accuracy.

We also note that Accuracy should be determined against the information used in DSO decision making, which is, for good reasons, more conservative that average expected behaviour.

This alignment is crucial to create a level playing field between different flexibility options and between flexibility and network upgrades as well as clearer decision making (misaligned baselines may under or over value the action).

At the point of ‘planning the network’ and securing availability – months or years before delivery – a fixed baseline (based on a reference class or historic behaviour of the individual asset) is an accurate and simple reflection of the counterfactual as it aligns with network planning assumptions.

In the context of long-term auctions, we believe UK Power Networks could align to the use of fixed baselines like National Grid Electricity Distribution’s, to cover additional technology types such as heat pumps and to reflect planning assumptions for storage and generation. Availability payments could be calculated in relation to these fixed baselines.

At operational time frames, DSOs are implementing short term forecasts to understand the need for flexibility service utilisation.

These tend to be based on recent historic loading across the network taking into account recent network measurements and local weather forecasts. These forecasts provide the most accurate counterfactual for dispatch decisions and can differ significantly from conditions at the planning stage. Whilst not using identical methodologies, a recent history baseline may be seen as more accurate as it is using similar concepts. However, the complexity of asset change management, and which events to remove from historic data remain. As such it may be simpler to determine a fixed baseline.

Whilst less “accurate” this may prove a lower barrier to entry. However the potential misalignment between the DSO forecast and the baseline means the DSO may procure a response already factored into the needs assessment. This could add risk to the network, and require DSOs to over-procure, reducing available pricing.

Additionally, consideration is needed for the utilisation of longer-term products in operational time frames (such as the Scheduled Availability Operational Utilisation product). Whilst availability decisions might be made against planning assumptions, utilisation decisions would be made against operational forecasts, creating a potential mis-alignment between baselines.

The concept of a Joint Utilisation Competition could be used to deliver this. This would honour long term contracts, their initial terms and baselines, but allow for resubmissions of utilisation prices, and associated baselines, to create genuine competition between long- and short-term products.

Questions

6. Do you agree that fixed baselines align well to the principles in planning timescales?

7. Would you prefer to see the used of fixed, nomination or recent history baselines in operational time frames?

8. How can we ensure fair utilisation of longer term and shorter-term contracts if different baselines are used?

9. Are there other options for baselining that we should consider?

5. Building trust in flexibility delivery

Definitions

Development Performance
Realisation of awarded volume under longer term contracts, e.g. if a provider offers 10MW in 3 years' time but only delivers 1MW then their development performance is low.

Operational Performance
Delivering in line with dispatch instructions following a proving test, e.g. if we instruct 5MW of flexibility for tomorrow and a provider delivers 5MW, their operational performance is high.

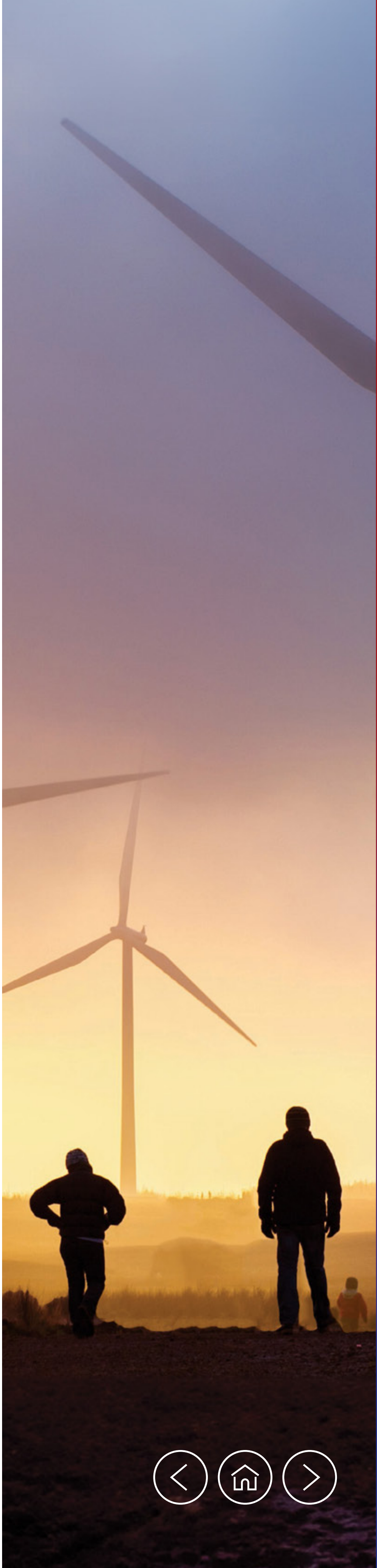
Why trust in delivery is important

Trust underpins all markets, and is particularly important in the context of emerging markets such as those for local flexibility.

Ensuring flexibility is reliable is key to value to the DSOs.

To help defer reinforcement and to manage subsequent network risk, DSOs need confidence that flexibility contracts entered into, be it years in advance or closer to real time, will deliver as promised. Failure to deliver can create additional network risk, which may lead to reduced security of supply.

Equally, responsible flexibility providers want to know that reliable performance will be rewarded and that the flexibility they offer will be valued accordingly and not be crowded out by speculative competitors who fail to deliver.



5. Building trust in flexibility delivery

Our experience to date

We have both avoided imposing penalties for performance, in order to minimise barriers to entry. This approach has been successful in growing participation, particularly from smaller players.

Operational performance following a proving test has generally been high, with some site specific exceptions. When we send dispatch signals, the vast majority of flexibility providers respond reliably, although the use of 'recent history' baselines can mean that a 1MW unit generating at full capacity may be marked as delivering significantly less if it judged to be normally running at that time. In adopting a fixed baseline rather than 'recent history', National Grid Electricity Distribution has avoided such performance mismatches.

The table below illustrates operational performance from flexibility dispatched by UK Power Networks and National Grid Electricity Distribution last year. It covers flexibility dispatched for HV zones.

	Bottom quartile (ie 75% of dispatches are better than this)	**Median**	**Top quartile**
Delivery as % of requested output	86%	>100%	>100%

Historically, we have both allowed 'planned' assets to participate within long-term flexibility contracts. As these contracts have reached operational stages both have seen a significant drop off in the volume of assets available, i.e. development performance has generally been poor. While this partly reflects the inherent difficulty in accurately forecasting long-term customer growth within particular locations, there have been instances where flexibility providers appear to have offered speculative, rather than realistic, volumes.

In these instances, while the DSO may request a delivery plan and challenge flex provider assumptions, providers see limited down-side to securing contracts with higher volumes than they can realistically deliver.

This pushes more network risk onto the DSO, which materialises at a time where mitigations are limited to operational, rather than planning, actions. It can also mask the need for more flexibility, distorting the results of flexibility tenders and prevent providers with actual flexibility from participating.

For example, some providers managing EV charge points have delivered less than 1% of their contracted volumes, while some generators have shifted their focus to alternative markets.

As such, and to provide a consistent process across short and long term markets, National Grid Electricity Distribution no longer allows for planned assets in its trades.

Changes to the assets providing the response are allowed, to account for inevitable changes in portfolios and short term markets are available for assets once they are built. This allows for greater clarity of the available volumes in markets for DSO decision making.

All performance incentives are currently based on reducing payments for low performance (including by reducing availability payments), rather than exposing providers to penalties.

This is generally the status quo across DSO markets. These incentives (along with liabilities unrelated to delivery) are currently being standardised through the Open Networks programme.

5. Building trust in flexibility delivery

Our proposed way forward

As local flexibility markets mature, we believe there is a growing case for more active performance management, noting that any additional measures should not create additional barriers to entry for flexibility providers who plan to deliver.

As such we are keen to start a conversation with flexibility providers about how this should be done and what mitigations will be needed to ensure they deliver the intended outcome.

Measures should be proportionate and reasonable, supporting competition for delivery on a level playing field, with risks held by those best placed to manage them.

We believe that DSOs should manage overall network risk through over-procurement and other fallback solutions, while providers should be able to manage risks of their asset reliability.

We believe that alongside any performance management measures, we should consider introducing additional means to mitigate or compensate for risk.

For example:

- Secondary trading of long-term flexibility contracts could reduce the risk associated with Development Performance (see Section 6).
- Greater use of availability payments could re-balance risk and reward.
- Expansion of day-ahead markets would reduce the risk that planned assets are locked out of markets.

Development Performance: Options for incentivising realistic long-term capacity declarations

National Grid Electricity Distribution is minded to continue to require that flexibility units are operational at the time of contract.

UK Power Networks is minded to continue to allow planned assets to be granted long-term contracts, but could request a small associated bid bond to be provided.

This could apply above a certain minimum capacity and be returned on successful passing of a proving test.

For example, we could require that any provider with more than 10MW of ‘planned’ assets lodge a bond of £2,000 for each MW above that threshold. Alternative options include the addition of greater financial penalties for non-delivery.

These would need to be capped and proportionate to the value of the contract.

Operational Performance: Options for driving more reliable response to dispatches

Options include the extension of bid bonds to cover this stage or the introduction of capped penalties proportionate to the contract value.

Both could be triggered for repeated and significant under-delivery.

Questions

10. What are your views on our proposed approaches to mitigating Development Performance risks?

11. What do you see as the most significant challenges to delivering high Operational Performance? Which options to mitigate penalties would most help you manage the associated risks?

6. Prioritisation of secondary trading

Definitions

Secondary Trading
Secondary Trading allows holders of flexibility service contracts with the DSO to transfer them to others – who would then take on the direct contractual relationship with the DSO.

What benefits could secondary trading bring?

Enabling providers to transfer their responsibilities could allow them to better optimise their assets across different markets – for example by transferring their DSO requirements to allow them to access higher revenue opportunities in other markets.

The benefits would depend on the extent to which market opportunities are not equally valuable or accessible to all parties.

Secondary trading could also enable additional participation by allowing service providers to gain access to contracts outside of biannual tenders.

Finally, if secondary trading were to be combined with non-delivery penalties, it could enable more reliable delivery of flexibility services if providers who cannot meet their obligations can transfer them ahead of time to those who can.

Our experience to date

Over the past few years, we have both explored the concept and practicalities of secondary trading. Both see a role in DSOs facilitating trading, but with a limited role in match making. This is a space open to various market platforms and services.

In early 2024, **UK Power Networks worked with LCP Delta** to understand the priorities of flexibility providers, along with lessons that can be learnt from secondary trading initiatives in other markets.

This concluded that the need for secondary trading is currently unclear and that in the short term UK Power Networks should focus on embedding the benefits of its day-ahead flexibility market.

National Grid Electricity Distribution's engagement with stakeholders has also pointed towards a focus on improving access to primary markets rather than focusing on secondary markets.

This does not mean that secondary trading is not allowed.

Over the past 12 months, UK Power Networks has facilitated one secondary trade between providers, where the original provider identified another provider to take on their obligations.

However, this process is currently manual, and would require work to make more scalable.

6. Prioritisation of secondary trading

Our proposed way forward

In the short term, we both plan to focus on development of primary markets for local flexibility services, including introduction and expansion of closer to real time flexibility procurement.

Both parties will re-assess the need periodically to ensure that the required support can be put in place in a timely manner. The approach would then be shaped by the lessons learnt from any relevant initiatives, eg ENW's BiTRADER innovation project.

Questions

12. In the short term, do you agree that the option to participate in local flexibility markets closer to real time would deliver much of the potential benefits of a secondary market?

13. By when do you think we will need a facilitated secondary market for flexibility service contracts? What market conditions will signal that need?

7. Summary

We wrote this document to highlight the alignment between both organisations and to gather stakeholder feedback together.

Whilst our internal systems and processes may differ, many of the challenges we face do not, and building on the collective learning between the organisations will drive a more efficient market.

Thank you for engaging with our proposals. We would be grateful for your thoughts.

You can provide feedback via **Slido** until 23 August 2024.

We will provide a summary of responses and our next steps in Autumn 2024.

UK Power Networks
237 Southwark Bridge Road,
London
SE1 6NP
United Kingdom

dso.ukpowernetworks.co.uk

National Grid Electricity Distribution plc
Avonbank
Feeder Road
Bristol BS2 0TB
United Kingdom

nationalgrid.co.uk

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