Energy UK

The voice of the energy industry

Energy UK response to Ofgem's Call for Input on Locational Charges and Regulatory Siting Levers Under Reformed National Pricing

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About Energy UK

Energy UK is the trade association for the energy industry, representing companies investing billions of pounds to secure our country's current and future energy needs.

From growing start-ups to major electricity generators, grid and infrastructure developers and energy suppliers, our members are driving change across power, heat, transport and flexibility.

We provide a collective voice for the sector working with governments, regulators, charities and other organisations to provide crucial insight that shapes policy, offers solutions and promotes best practice.

Our broad view across the whole system supports evidence-based positions which are not tied to particular technologies, and are focused on delivering strategic benefits for people, businesses and the economy.

We champion initiatives such as our Vulnerability Commitment, which pushes suppliers to go beyond regulation to support customers with additional needs, and TIDE, the industry's drive for greater inclusion and diversity. Through our Young Energy Professionals Forum, we support the development of future leaders.

We are equally committed to our team and are proud to be recognised as a 'Gold' Investors in People employer.

Executive Summary

Energy UK welcomes Ofgem's work on Locational Charges and Regulatory Siting Levers under Reformed National Pricing (RNP), and would note the following core positions:

- The current network charging framework must be reformed through both immediate actions to reduce uncertainty and longer-term holistic reform to align with wider levers being explored in the DESNZ RNP Delivery Plan.
- Ofgem must continue to engage with a wide range of stakeholders to consider the actual impacts and consequences of any changes before implementation.

- Coordination of this work with the Cost Allocation and Recovery review is critical, as the impact on affordability must be considered.
- Action to address uncertainty should be urgently pursued, in light of upcoming market and support mechanism auctions, to reduce the risk premia applied to projects critical to delivery of Clean Power 2030.

Sector confidence is low following significant delays to critical workstreams, market uncertainty, and geopolitical circumstances. Energy UK would welcome closer, more regular engagement and the broader consideration of actions DESNZ, Ofgem, and NESO can take to improve the investment signals for developers.

If you would like to discuss anything noted in this response in more detail, please do get in touch.

Sincerely,

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Consultation Response

Q1: Do you agree with our assessment criteria for locational charging options?

Energy UK broadly agrees with the five criteria, with certain important clarifications. The existing approach to charging is no longer fit for purpose, and the intention to address this is welcome.

Ofgem should consider how the levers explored interact with political risk to ensure the durability of arrangements, which would help maintain investor confidence. Wider clarity over how Ofgem, the National Energy System Operator (NESO), and the Department for Energy Security and Net Zero (DESNZ) will coordinate delivery of investor certainty through effective actions across price signals, governance, and legislative frameworks would be welcome.

Spatial planning and the connections regime will shape siting decisions for new build projects, and Energy UK supports the intention for a reformed charging framework to encourage capacity to connect in line with the best value to the system. The current charging regime is no longer fit for purpose, in that it was designed for an electricity system that is no longer relevant, and now exposes developers to unexpected losses and gains after a siting decision has been made.

Transitional and legacy assets will be unable to react to changes in locational signals, as investment and siting decisions have already been made. Clear principles on legacy arrangements and timelines is essential to maintaining investor confidence and preventing uncertainty that currently risks early closure of existing assets.

The criteria appropriately align with the developing Strategic Spatial Energy Plan (SSEP) but should explicitly acknowledge that whilst the SSEP sets the envelope of what is needed where, connection processes and/or charges fine-tune selection within that envelope. The SSEP is yet to be finalised, and as such does not deliver any inherent improvement to investor confidence.

<u>Wider System Value</u>
The SSEP is not itself a price signal for locational investment. Locational charging is one of the levers to support the SSEP by delivering that signal, enabling cost-effective delivery of the SSEP by enhancing the predictability of charges, enabling efficient investment decisions by a robust, competitive market.

Ofgem should clarify the distinction between this criterion and the efficiency criterion, given that the aim of the SSEP should be the least-cost, most-efficient approach to system design and delivery. The two criteria should not overlap or create confusion.

Efficiency
Greater predictability, both in terms of visibility and reduced risk of volatility, is needed to give confidence to investors. A marginally more accurate but undeliverable signal is less efficient overall than a simpler approach that can be robustly implemented.

An appropriate balance between cost-reflectivity and predictability must be maintained.

Investability
This criterion is critical and insufficiently emphasised in the majority of the proposed approaches. Investors need clarity not just on charges themselves, but on whether and how charges will evolve over the asset lifetime. Further clarity is needed regarding the potential for charges to be fixed at various investment decision points, and how more certain charges would be shielded from the impact of future SSEP iterations or wider market conditions while continuing to deliver the required investment in the network itself.

The ongoing risk of failure to develop the robust network supply chains and skilled workforce required to connect projects continues to impact investment confidence, and recent increases in the cost of connection and delays to timelines for connection under newly issued Gate Two connection offers raise further concerns. Industry is continuing to engage with NESO regarding the SSEP and further improvements to connection processes, and welcomes the engagement to date from NESO.

Competition
Competition is fundamental to the efficiency and cost-effectiveness of the market, essential at two levels: within SSEP zones (choosing between viable projects), and across SSEP zones (if headroom is provided, enabling competition for the same envelope of authorised capacity). Without headroom within zones, the regime risks becoming allocation without competition, which would be fundamentally inefficient.

Deliverability
Deliverability requires clarity on ongoing governance and dispute resolution, and transparency of underlying assumptions. Sufficiently strong transitional protections for assets reaching Final Investment Decision (FID) before implementation would give more time for the comprehensive design of a new regime.

Q2: Do you prefer any of the five options? If so, why?

Energy UK does not support a single option at this stage. Member views vary on the best approach, but without further detail on the intended implementation approach and targeted outcomes for each option, it is not possible to support any option.

TNUoS, as it is currently applied, is not fit for purpose, either in the immediate term or the long term. Transitional arrangements should be pursued urgently to improve certainty while the longer-term reform of charging is developed and implemented. A clear indication of the direction of travel for these transitional arrangements should be set out ahead of upcoming investment rounds such as Contracts for Difference (CfD) Allocation Round Eight (AR8).

Option A, as recognised in the Call for Input, may not address some of the key issues in current charging arrangements. More detail would be needed regarding how the approach would address volatility.

Energy UK recognises the merits of the proposed framework for interzonal charges (between SSEP zones) set out under Option B (Network Utilisation Impact Charge). More detail would be required from Ofgem for the industry to support any option in full, and further engagement with expert groups should be pursued to better design options B and C.

Through modelling based on the Centralised Strategic Network Plan (CSNP) and proposed network build, rather than the existing network, more frequently updated charges on a multi-year cycle, aligned with SSEP iterations, could provide charge trajectories to developers in advance of investment decisions.

Q3: For each of the options presented, what do you see as the key costs, benefits, and system-wide implications?

It is difficult to assess the costs, benefits, and system-wide implications of these options without further development and engagement with industry regarding implementation and potential unintended consequences of each option.

All options hold inherent risk: if network buildout is delayed following CSNP modelling, charges will be greatly misaligned. Recent experiences with Connections Reform give the industry a level of mistrust in projected build-out, as networks may, at a later stage, state they are unable to deliver due to wider constraints, for example, in supply chains and skilled workforce. Ofgem's decisions regarding critical network upgrades have also impacted confidence, as strategic High Voltage Direct Current (HVDC) upgrades have seen delays that will extend constraints into the 2030s. Indeed, the RNP Delivery Plan notes that existing constraints are primarily the result of insufficient network build-out, and not the result of generation siting decisions.

All options hold an inherent risk that, without sufficient coordination efforts, they will be misaligned with the SSEP, or with future versions of the SSEP. Ofgem and NESO must set out how charging and spatial plans will be aligned effectively regardless of the option pursued.

Regardless of the option selected, there is a critical need to deliver significantly enhanced (more granular, more accurate, and more transparent) modelling capability to best estimate the future cost of the system. The transparency of any option would be dependant on the level of transparency embedded in NESO forecasts and the baseline assumptions applied.

Option A: Targeted Changes

Benefits

- Minimal disruption
- Fast implementation, potentially the most deliverable by 2029
- Known approach with existing industry familiarity

Costs and Risks

- Without significant reforms, there is a risk that this approach would not address root issues with the existing methodology
- Continuing volatility, if TNUoS is not also fixed or stabilised against transparent projections of actual system costs, targeted changes alone do not solve the predictability problem
- Potentially weak SSEP alignment, depending on which changes are taken forward
- Ongoing tariff complexity

System Implications

- Persistent constraint costs if fundamental issues are not addressed under the NESO constraints workstream and the RNP Delivery Plan
- Limited strategic progress

Option B: Network Utilisation Impact Charge

Benefits

- Reflects spare network capacity in the locational signal
- Potential to better align with SSEP in terms of enabling charges to vary to enable the cost-effective delivery of the SSEP, if the approach is based on CSNP-modelled future network

- Zero charge where spare capacity exists would incentivise connection in unconstrained areas, with potential impacts based on whether this applies as an intrazonal or interzonal charge
- Potential to better reflect the cost of expanding the network

Costs and Risks
- Subjective assumptions on what constitutes 'spare capacity'
- Charge volatility risk, particularly around cliff edges where a single project consumes the last spare capacity on a circuit
- Update frequency issues: too frequent and charges become unpredictable; too infrequent and they lose cost-reflectivity
- First-mover disadvantage risk: if Project A triggers a network upgrade, Project B, connecting shortly after, benefits from the newly created spare capacity at little or no charge. This fairness issue needs to be addressed in the design, recognising that a ‘build once’ approach to reinforcement offers longer-term cost efficiencies.
- Potential to result in false accuracy when attempting to reflect the actual cost of network expansion, given the dependence on uncertain forecasts and subjective assumptions.

System Implications
- Incentivises smart siting relative to planned network
- More efficient network utilisation over time
- Cliff-edge/first-mover issue as a significant design challenge that warrants explicit treatment in any Option B design. Charge volatility risk may also depend on whether LRMC or LRIC (Long-Run Incremental Cost) methodology is used, as well as on update frequency and input assumptions.

<u>Option C: System and Constraints Impact Charge</u>
Benefits
- Strong alignment to both SSEP and CSNP if network build proceeds on schedule
- Certainty would be increased by transparent SSEP/CSNP outputs, which would allow for charges to be averaged or fixed based on these pathways
- Could reflect spare capacity in the system

Costs and Risks
- Major methodological shift from current regime, requiring more resource to implement, a longer implementation timeline, and higher transition costs
- Complex system modelling requirements; NESO is currently unable to produce accurate constraint forecasts and publishes projections that can differ significantly from outturn.
- Risk of conflating operational constraint costs, properly managed through BSUoS and balancing markets, with long-run locational investment signals. Any potential that

costs currently covered by BSUoS could be shifted into TNUoS must be resisted; operational constraint costs should be dealt with on operational timescales using operational tools
- Clear need for specificity in definitions, in particular for what is 'Optimal', which may be subjective

System Implications
- Incentivises smart siting relative to planned network, but would need careful alignment with the SSEP and CSNP
- More efficient network utilisation over time
- Strong potential for alignment to SSEP and CSNP if delivered on schedule
- Misalignment risk if network build is delayed and does not align with the SSEP or CSNP timelines. This could be mitigated by basing charges on an optimal future, reflecting the grid as if planned reinforcements were in place, to reduce the risk that generators are penalised for network delivery delays outside of their control.
- Higher transition costs possible
- System balancing and operational costs boundary needs careful interrogation, including examination of what part of the system is being optimised. Some members consider the scale of the modelling challenge to be materially understated in the current treatment.

Option D: Metric-Based Charge

Benefits
- Simple calculation methodology
- More predictable for investors than modelling-based approaches
- Built-in SSEP alignment if the metric is well-designed
- Low governance complexity relative to Options B and C
- The current DCLF ICRP (DC loadflow investment cost related pricing) model is already a metric-based charge that uses incremental MWkm weighted cost of existing network as a proxy for future network reinforcement.

Costs and Risks
- Lack of a fundamental basis for the charge, it is a major departure from the principle of cost-reflectivity that has underpinned TNUoS
- Subjective metrics: the methodology for converting a metric like generation-to-demand balance into a charge level is currently both unclear and likely to be arbitrary.
- Risk of crude signals that do not reflect actual network conditions
- Potential unintended consequences, particularly where the metric has the potential to produce perverse incentives
- Technology fairness issues: different technologies may be treated inequitably by a simple metric

System Implications

- Improved simplicity if the metric aligns well with underlying network conditions
- Risk of distorted investment if metric design is poor
- Potential fairness gaps across technologies and locations: the methodology for translating a metric into a charge level is a significant unresolved problem that the response should address explicitly

<u>Option E: Plan-Based Auction Pricing</u>

Benefits

- 'Market-based' pricing, though the market would be heavily influenced by constraints imposed by policy and regulatory decisions on connections and zone capacities.
- Transparent valuation, though it is not clear what value the auction price would be based on.
- Competition potentially preserved if sufficient market players participate.
- Flexible zone capacity allocation.

Costs and Risks

- Demand-based/value-based rather than a cost-based charge, resulting in unpredictability and a lack of fundamental justification for the locational charge level, impacting value for money for consumers.
- Offshore wind developers would face three separate auction processes: seabed lease, connection capacity, and CfDs. This creates a significant timing and coordination burden.
- Complex auction interactions: for example, a developer cannot finalise their connection auction bid without knowing their CfD strike price, nor their CfD bid without knowing connection costs. The same can be said of other technologies engaging in other market mechanisms.
- Participation and market power risks in zones with low liquidity.
- Timing misalignment between connection auctions and support mechanism auctions, and a lack of clarity regarding how merchant projects would participate if auctions are aligned with market tenders that they do not take part in.
- Lack of clarity around how auctions would work in practice across zones with very different levels of project interest.
- Price in any auction would be heavily dependent on decisions made around timing and availability of connections, undermining claims to genuine market pricing.
- If zones need to be bundled to ensure sufficient liquidity, that is likely a signal that auctions are not appropriate in that context

System Implications

- Efficient allocation if the market is liquid
- Inefficiency risk if poor liquidity

- Underutilisation risk in zones with insufficient participation.

System-wide, competition, and efficiency implications for Option E depend on whether or not the proposed auctions would be coordinated with wider auctions and processes.

Coordinating these auctions into a single price could deliver more efficient allocation, but these auctions and markets operating at different times or being misaligned would cause significant inefficiencies. If the Government wants to pursue auctions comprehensively, a continental-style bundled auction might be more coherent, though this would further reduce developer agency.

Q4: How does each option perform against the assessment criteria?

Ofgem has not provided sufficient detail regarding how the options would be implemented for Energy UK to answer this question meaningfully. Ofgem must set out clearer definitions of terms, for example, ‘wider system value’, for industry to meaningfully comment on each option’s potential impact.

Each of the options proposed could perform fairly in most categories, but it is impossible to quantify exact performance without clarity on the approach taken both within these reforms and to wider RNP reforms.

Q5: Are there options not considered here which we should be exploring?

Energy UK recognises that a single approach risks inadequacy and does not account for regional, market, or technological specifics.

Ofgem should consider a hybrid structure with different signals for different purposes:
- Interzonal locational signal (between SSEP zones)
- Intrazonal signal (within SSEP zones)
- Headroom incentive (where zones are under-built relative to SSEP targets), as being explored in the RNP Delivery Plan
- Constraint management (addressing persistent constraint costs), as being explored in the RNP Delivery Plan and NESO workstreams
- Fixing charges based on specific timelines, contract lengths, or lifetime operation

This would ultimately allow each lever to play its intended role while minimising complexity. Technology differentiation is one example of this. It is important to be clear whether the differentiation being argued for is:

- Technological differentiation, treating solar, wind, nuclear, and storage differently based on their operational network impacts; or
- Contractual differentiation, treating assets differently depending on whether they are supported by a market or support mechanism or operating on a merchant model.

A 'one-size-fits-all' approach would not deliver the intended results. The approach must deliver a level playing field for all technologies, and arrangements need to be designed to avoid market distortions. For assets supported by a market mechanism, charge fixing would deliver improved value for money across those mechanisms, reducing the cost of bids by reducing uncertainty. However, stating that all scheme-backed generation requires fixing may overstate the case; the Capacity Market (CM) in particular covers close to the whole market, so broad fixing on that basis would not be targeted, but may still be appropriate for most or even all of the market.

The case for demand-side locational charging is more unique. To influence the location of projects such as data centres and electrolysers, in some cases more geographically flexible, the application of locational TNUoS charges should align siting with generation assets. This could include negative charges in generation-constrained areas, with phased implementation starting with transparent forecasting.

For energy storage and other flexible technologies, the wide range of potential technology types and primary value propositions (constraint relief, time-shift, energy arbitrage) may require more detailed consideration. The coordination of wider operational signals via market mechanisms and other levers would be needed to ensure that system-wide and local benefits are realised. Ongoing code changes for energy storage charging arrangements and negative pricing should be considered in the assessment of options, and in the application of transitional arrangements to address the current uncertainty.

Q6. What are your views on the possible changes outlined in Option A? What other alterations could be made to the current methodology to support the SSEP and deliver benefits? Please include views on:

- **How far a modified transport model could be well aligned with the SSEP.**
- **To what extent a modified transport model could be used to reflect spare capacity and how it could be done effectively.**

Energy UK agrees that replacing 27 generation zones with 19 SSEP zones would align charging boundaries with planning boundaries.

Enhancing the transparency of inputs and assumptions, including publication of underlying demand forecasts, network plans, and cost assumptions, would support this process.

Q7. What long-run costs should NUIC reflect, particularly in the context of the growing share of network investment made anticipatorily through the CSNP rather than responding directly to the connection of new assets?

Regarding option B (NUIC), long-run costs should include anticipated network costs, based on the CSNP.

Consideration of how and when wider incremental costs beyond CSNP forecasts would be included must be further developed. It may not be appropriate to apply incremental costs to existing and developing generation that will connect before these reforms are implemented.

It would also be important to set out the baseline definitions and clearly define what terms such as "anticipatorily" mean.

Q8. Should the costs of network build determined by strategic planning be recovered on the same basis as the network build required by assets locating outside of the SSEP (and therefore requiring network beyond the SSEP's optimisation)?

The purpose of locational charges must be clearly defined.

Locational charges would be best applied where parties can respond to those price signals, not as an additional revenue-raising mechanism to cover insufficient cost-recovery mechanisms. Costs should be recovered via other methods to ensure the fair treatment of SSEP-aligned assets, appropriate incentives for out-of-SSEP development, and consumer cost minimisation.

For SSEP-aligned generation, recovery of costs could be delivered through shallow connection charges (existing level) alongside TNUoS. This TNUoS charge would be reflective of the marginal impact on the network relative to the anticipated investment. As the CSNP delivers optimised system-wide investment, all customers benefit, and as such, a proportioning of costs across all users would be appropriate.

However, this must be carefully considered to avoid unintended consequences. If SSEP-aligned generation only pays shallow charges, the approach to recovering costs for significant CSNP upgrades would need to be considered. The SSEP and CSNP determine where the system will need to be upgraded, not how the cost of doing so should be recovered. It is critical that this is coordinated with the Cost Recovery and Allocation Review to ensure that the recovery of costs is fair, appropriate, and efficient.

For non-SSEP-aligned generation, Ofgem should first consider the likelihood of assets being sited outside of areas encouraged by the SSEP. Under the RNP Delivery Plan, the options set out heavily encourage developer alignment with the SSEP and limit the potential for assets to be misaligned.

Costs for non-SSEP-aligned projects could be recovered through deeper connection charges, recovering site-specific additional reinforcement costs. Generators choosing locations outside the optimised plan could bear incremental costs through higher TNUoS charges reflecting unplanned reinforcement needs. In addition, to prevent gaming and ultimately protect consumers from bearing costs of suboptimal siting choices, the optimal combination of deeper connection charges and an appropriate TNUoS charge will need to be calculated.

If the approach does not coordinate capacity caps with market auctions, developers and generators will not know what their network charge will be. As such, it will be impossible to accurately bid into market mechanism tenders.

Regarding legacy and transitional (LAT) arrangements for projects with connection offers issued before the SSEP was finalised, further clarity is required. As it stands, whether these projects will be eligible for LAT arrangements is unclear: It must be clarified whether LAT eligibility would be based on FID timing relative to locational network charging reforms, rather than SSEP finalisation.

Q9. If an LRIC-type methodology were developed for transmission network charging, how could the concepts of (a) time-to-reinforcement and (b) baseline demand projections be adapted in the context of strategic planning and anticipatory network reinforcement?

If an LRIC-type methodology was pursued as a variant of Option B, adapting time-to-reinforcement to a plan-referenced framework would be required. The approach should use published SSEP demand forecasts as a baseline, not independent assumptions. A charge-fixing mechanism to manage volatility would need to be adapted to align with strategic planning and anticipatory network reinforcement.

A key aspect of this scenario would be the need to publish detailed forward-looking charge profiles showing the trajectory over the asset lifetime.

Q10: Could any other LRMC approaches be used to send a locational signal to support the SSEP or deliver wider system benefits? Please clearly indicate any relevant methodologies, including those applied in other international contexts.

Ofgem should look to international examples as part of its assessment of options. Some of the examples currently applied in different markets are set out below.

The Swedish Forward-Looking LRMC, proposed for implementation in 2027, follows load flow modelling of projected generation, demand, and network, determining whether incremental supply/demand would overload the grid. In that instance, where there is no overload, the LRMC charge would equal zero, whereas if there was an overload, the charge would reflect reinforcement cost and timing. Some key advantages of this approach would be that it directly reflects spare capacity and is forward-looking. Because it requires an accurate load flow model and demand forecasts, and has potential governance challenges, it would need to be determined which forecasts are used. This approach could, in theory, be applied under the existing DCLF ICRP model and, as such, may not require a new model to be implemented. This requires further consideration and engagement on what would need to change for the transport model to accommodate such a change.

The congestion-reflecting LRMC is used in countries like Denmark or Australia. Charges reflect whether the location is in a "production-dominated" or "consumption-dominated" area. In production-dominated areas, users pay higher charges, whereas in consumption-dominated areas, users pay less. Because of the simple metric of generation balanced against demand, rather than detailed modelling, the fundamental calculations and effective directional signals toward demand centres would be easier to implement. This system would not account for network capacity between areas and could risk poorly incentivising locations that are balanced but still constrained.

A third model is the net cost of connection/incremental tariff as it exists in Chile. This approach combines fixed connection charges reflecting asset-specific works, as well as variable locational charges that reflect network utilisation impact. In this case, connection charges (site-specific) and TNUoS charges (network-wide) could be applied in the UK. Because charges are explicitly separated into two components for transparency, it would be clearer to developers which charge reflects site-specific costs and which reflects network costs. This system, however, would come with some implementation burden and a complex interaction with residual charges that would need to be addressed.

Q11: What additional measures might be required to deliver effective locational signals using the approach in Option C?

For Option C, some of the measures may include:

- Binding CSNP delivery timelines and Network Build Guarantees:
  Network build schedules must be legally binding, with enforcement consequences. Currently, the CSNP is not legally binding; NESO will set out proposals for Transmission Operators (TOs) to deliver. If delays occur, a charge adjustment mechanism or financial compensation to generators should apply.
- Transparency on delivery risk:
  Contingency timelines if primary plans slip, given that Option C charges rely entirely on CSNP modelled outcomes.
- Major improvement in NESO modelling capability:
  NESO is currently unable to produce accurate constraint forecasts and instead publishes projections based on Future Energy Scenarios, which can differ significantly from outturn. Option C cannot function credibly without substantially better modelling. Substantially improved NESO modelling capability is a prerequisite for Option C to function, not an optional enhancement.
- Publishing baseline assumptions:
  Demand forecasts and technology mix assumptions for each zone should be published alongside the charges.

The options set out above to incentivise network delivery still do not address the challenges faced by generators if network delivery is delayed or demand is lower than NESO projections.

If the approach to Option C is based on NESO forecasts of constraints, this would present a significant commercial risk for generators. It is impossible, at this stage, for NESO to accurately predict how much generator response will be received to any given price signal, or how constraints will actually emerge. If generator responses are above or below the estimate, the price signal will be incorrect, with no counterfactual to test accuracy or adjust based on actual impact.

Charges under Option C could be driven by broader system conditions and future constraints over which a legacy/transitional project has no control. These projects will have made an irreversible location decision in line with network charging and broader system and policy context at the time of investment. Clear LAT arrangements will be needed to avoid locational signals applying to generators that are unable to effectively respond.

Q12: Are there any alternative approaches integrating SSEP outcomes to send a signal reflecting assets' wider system impact, including constraints?

An alternative approach would be to use multiple complementary signals rather than a single unified charge reflecting all system impacts. These signals could include an Incremental Network Cost Signal (Option B), reflective of spare capacity relative to planned network buildout based on LRMC, with a simplified metric reflecting generators' impacts on specific constraints, based on SSEP/CSNP identification of constraints.

It should be noted that, at present, dispatch decisions are made by the market, and this approach should continue regardless of which network charging option is taken forward.

Q13: To what extent could a metric-based charge act as a complementary 'top-up' signal alongside a broader charging methodology, rather than operating as a standalone approach? What challenges would this present?

A metric-based charge would be better suited to a complementary role than as a primary charge, and can effectively provide focused signals for specific objectives.

Using a metric-based top-up approach as a complementary element to the Option B base methodology, where the primary charge is the Network Utilisation Impact Charge, could be applicable, and the complementary metric could be SSEP Alignment, with rebates for lagging zones and penalties for exceeding certain limits.

A main challenge would be governance, and whether or not Ofgem, NESO, or the Government would need to establish a steering group and annual review to ensure efficiency.

Q14: What other metric-based approaches might be a suitable basis for setting charges?

An SSEP alignment metric is objective and can be calculated with a level of certainty. Similar proven approaches are implemented in other countries.

A Network Headroom metric, for intrazonal use, could reflect physical constraints and incentivise the use of spare capacity, though it would be complex to implement.

It is appropriate to reflect a forecast of structural spare capacity versus SSEP capacity ranges. However, charging should not apply a premium to reflect forecast constraints above the efficient level. A forecast of excessive constraints should be addressed via other levers, such as CfD technology, locational maxima, or compensation for volunteering to delay connection dates.

Q15: What interactions do you foresee between plan-based auctions for generation, government support mechanism auctions and the connection regime? What potential implementation risks and mitigations should be considered?

Plan-based auctions like Option E depend on successful integration with timelines and processes for market auctions, and with wider connection processes. Timing Misalignment would be one of the crucial elements that would impact the effectiveness of this model.

Under Option E, a developer would need to bid for connection capacity before a CfD/CM is awarded, but the developer cannot finalise the bid without knowing the CfD/CM strike price or CM clearing price, nor can they finalise their tender into market auctions without knowing the cost of connection.

Synchronising connection auctions with support mechanism auctions would reduce timing risk for bidders, allow for more informed bidding and maintain auction independence, though this would require very strong coordination between DESNZ, Ofgem and NESO and leave no flexibility for delays.

A second option would be a new interaction with CfD auction results, whereby CfD Allocation Rounds allocate capacity across multiple technologies and regions, and connection auctions allocate physical capacity across zones. In this scenario, CfD auctions could allocate capacity on a zone-by-zone basis, matching connection zones. For example, a CfD would allocate 200MW solar in the North and 500MW in the South, based on SSEP and CSNP, and connection auctions would then allocate these zone-specific targets with clear alignment with successful bids. The CfD winners would know their zone allocation and could bid into the corresponding connection auction.

There is a clear risk in this approach that the access auction would only have liquidity if some generators successful in an auction were expected to fail to secure access rights, resulting in contract delivery failures. Distortions to competitive processes could also be seen, as each generator would need to factor the anticipated cost of access into their bid, which will be unknown at the time of the auction.

There is also a risk in the complexity of delivering such an approach, particularly when considering Merchant assets that will bid into neither a CfD nor a CM. Linking auctions to market or support mechanisms would limit the flexibility of merchant assets have in development, so must be carefully and holistically considered. Any Option E design should not presuppose that all generators go through support mechanism auctions before accessing connection capacity.

Again, cost effectiveness for consumers must be considered in this approach, and efficiency and high levels of market liquidity should be targeted.

Q16: What design features could help ensure that auctions remain workable across zones with very different levels of project interest?

For multi-zone auctions to work across different liquidity levels in different zones, liquidity assessment, that is, a realistic assessment from NESO regarding participation expectations, alongside flexibility in design, where different formats for different zones apply, would be important features to make auctions workable.

Transparency will be crucial for developers to understand where and why different treatment is to be expected. Fallback mechanisms would need to be implemented to ensure capacity would be allocated even if low participation occurs.

Furthermore, in ensuring capacity is allocated even if low participation occurs, it should be noted that if zones need to be bundled to ensure sufficient liquidity, this may signal that auctions are not appropriate in that context, so bundling zones should not serve as a simple fallback mechanism.

Auctions may need to be pulled into a single mechanism that enables tenders for, for example, seabed leasing, CfD, and access at a single price. This is used in European markets, so there are existing approaches that could be reviewed, but this approach would likely be highly complex to introduce.

Q17: Could alternative mechanisms achieve similar outcomes with fewer risks or dependencies?

Outcomes could be achieved through alternative mechanisms rather than auctions, with the key alternative being financial commitment measures or pricing signals. This alternative may be preferable where there is insufficient competition to support an effective auction or where alignment with other levers, such as investment support schemes, is more important than precise allocation outcomes.

Q18. What role should locational charges for demand play in future? Please include views on:

- ***What types of demand users are likely to be able to respond effectively to a locational investment signal, and why.***
- ***Relevant international examples of demand siting decisions made in response to locational pricing signals.***
- ***What the charging basis for the signal should be if sending locational investment signals is deemed as effective for some types of demand.***
- ***How suitable the options for a locational charge set out above could be for demand, and whether there are other alternative charging approaches that could be applied for demand.***
- ***Whether different charging methodologies should be used for demand and generation, and any practical considerations in doing so.***

There are a range of potentially more geographically flexible demand projects looking to connect across the UK, but with the connections queue oversubscribed and land rights also in high demand, there is a risk that price signals would be too late to have a significant impact.

There is a case for providing enhanced locational price signals for demand customers who are able to effectively respond to such signals. This includes those who are yet to make siting decisions and those making new investments into, for example, electric vehicle charging, energy storage, and on-site generation. Work undertaken under CMP440 should be reviewed in the context of how demand charges could be improved.

Demand users who are more able to respond effectively to locational investment signals should be identified, and alignment with wider policy and regulatory frameworks is required. The DESNZ proposals for strategic demand acceleration and AI Growth Zones, as well as the wider policy ambition for housing, the Industrial Strategy, and utility investment must be factored into the design of charges to ensure that nationally significant demand is able to connect.

The majority of demand should remain on non-locational charges as it cannot respond to siting signals. Locational signals have the potential to accelerate or moderate electrification in different areas, impacting the uptake of electric vehicles (EVs), heat pumps, and wider demand-side technologies. Intentional and unintended impacts on end-user decisions should be further considered under this workstream, the Cost Allocation and Recovery Review, and wider policy and regulatory reforms.

Demand locational charges recover a small percentage of TNUoS demand revenue – around 3%. The vast majority of TNUoS demand revenue - around 97% - is recovered via the Transmission Demand Residual (TDR). It may be helpful to consider options to rebalance the role of demand locational charges versus demand residual charges, such as those proposed by CMP432, to change the TNUoS Reference Node, and CMP440, which would reinstate demand credits. As affordability is a key problem facing the energy sector right now, focusing on the TDR should be a clear priority, and Ofgem's Cost Allocation and Recovery review is crucial.

TNUoS revenue is ultimately recovered from demand through energy bills. If a larger portion of demand charges become locational, there is a risk that different demand types would pay different charges, including the potential for regressive impacts on domestic consumers. Clear justification and cost-benefit analysis for how that strategic demand will reduce local and national system costs, and how cost allocation and recovery will be adapted as charges are reformed, must be set out in advance to justify the approach.

If the role of locational demand charges were increased, these should use the same methodology as generation to avoid confusion and multiple charging models. Adapting Option B (Network Utilisation Impact Charge) for demand would ensure charges reflect where connecting demand reduces network reinforcement needs and where it increases needs. There may be a role here for deeper connection charges.

A design question not addressed in the Call for Input is whether demand that could shift locations should face a lower or even negative charge in one location and a positive charge in another. From an efficient, cost-reflective market design perspective, the answer should be yes. However, this may come with the risk that demand in high-charge locations may be incentivised to invest in on-site fossil generation to avoid the charge, one of numerous potential unintended consequences that should be considered.

There is also a countervailing consideration: negative locational charges may push up the demand residual for non-locational demand, but could lower balancing costs by an even greater amount by reducing constraints. The most cost-effective balance needs to be assessed.

Q19: What should be considered when designing a network charge for storage?

Storage presents unique challenges because it is both a generator and a source of demand. Charging must reflect this duality, and the varied roles storage can play (time-shift, constraint relief, system balancing, renewable firming). Fundamentally, network charges should be decided by the likely impact of an asset in a particular region, and operational signals for flexible assets should be sent by other levers and market signals.

Different signals, reflective of the primary value proposition (constraint relief, time-shift, energy arbitrage), may be needed, in full coordination with wider operational signals delivered by market mechanisms and wider approaches. In practice, most battery projects stack revenues across applications, and the actual profile will change over the asset's lifetime. As such, it may be necessary for the regime to reflect this ability to adapt, and fixed charges may not be appropriate for these assets.

Whether TNUoS fees paid by storage should have a locational element, guiding where assets are encouraged to site, in a strategically planned system.

The value of storage can be system-wide, and charging frameworks should ensure that flexible technologies that deliver clearly defined national benefits are recognised consistently across locations.

Many forms of storage deliver multiple stacked services, making it inherently challenging to send meaningful locational signals without coordinating across available levers. The operational behaviour of Battery Energy Storage Systems (BESS), for example, is complex and dynamic, with a significant proportion of value derived from intraday trading and real-time system response. This complexity has been discussed extensively within the TNUoS Storage Sub-group, and the work developed by that group to date should be considered in the approach to TNUoS reform.

Whether storage should continue to face the same charge as some forms of generation, or whether a more tailored approach should be considered

The treatment of storage, and more broadly flexibility, within TNUoS requires fundamental review to ensure that charging arrangements appropriately reflect the actual system impacts of flexible assets.

The current TNUoS classification framework creates inconsistencies in how storage is treated relative to other users of the network. Storage continues to be classified broadly alongside conventional generation, despite its fundamentally different operational characteristics and bi-directional interaction with the system.

Code modification CMP393 recognises the bi-directional nature of storage and the need for charging methodologies to reflect how storage assets interact with the transmission system. This work should be considered in designing a new approach to ensure fair and equal treatment of storage assets.

If a more tailored approach to storage charging were considered, whether or not differences in storage asset class and characteristics should be reflected. If differences should be reflected, please indicate which, with rationale.

Charging frameworks should ensure a level playing field across all storage and generation technologies, considering actual impacts on the national system and local network.

Differences in storage charging should not be based solely on asset duration, and should consider this among other factors. Storage assets optimise operation dynamically, and do not operate in a fixed manner aligned to their nominal duration. For example, a battery site with an eight-hour capability is unlikely to consistently discharge over a single eight-hour period. The asset is more likely to operate across multiple shorter periods depending on market conditions and system needs.

The extent to which the charging options (A-E) described above might be appropriate and provide useful locational signals to storage.

More fundamental reform of storage charging would be required alongside any of the charging options (A–E). Existing TNUoS methodologies do not adequately reflect the bi-directional nature of storage or the actual system impacts of the asset.

Energy UK members note that across the options, the following considerations should be noted for storage to be effectively incentivised:

- Option A would require changes, with full consideration of those outlined in the principles of CMP393, to represent the value of flexibility.
- Option B would require agreed methodologies to assess the net impact of storage on the network, as explored under CMP393. This option would require ensuring that storage modelling developed by the TNUoS storage sub-group is accurate and reflects actual operational behaviours and network impacts of assets.
- Option C is not well aligned with incorporating storage. This option is a major methodological shift from the current regime and does not provide robust consideration of the behaviours, forms, and benefits of energy storage.
- Option D could incur issues with fairness, as different technologies may be treated inequitably by a simple metric. A specific approach to modelling metric-based storage charges would be required.
- Option E would not work effectively for storage, given different locational and technical requirements across storage technologies. Without additional measures, a highly directive auction approach risks creating inefficient or distorted outcomes.

Whether network charges for storage should reflect the extent and characteristics of network constraints.

As noted by in the Call for Input, location is only one factor influencing the value that storage provides to the system.

Storage assets participate in a wide range of markets and activities as part of their business models. A whole-system consideration of storage impacts shows that storage located behind constraints delivers net benefits, including reduced wholesale prices and provision of essential system services.

Network charges that strongly reflect the extent and characteristics of constraints without full consideration of broader, whole-system impacts risk unintended consequences for both the system and consumers should be explored fully before selecting an approach.

Clearer operational frameworks, such as updated TCLC guidance to define how storage should operate during constrained periods, would be welcome.

Possible roles for any types of flexible connections for storage assets.

Flexible connections can reduce the operational optionality of storage assets, a key component of project viability.

Storage relies on the ability to optimise across multiple markets and system services, and excessive curtailment or access restrictions can materially undermine revenues and ultimately the viability of the project. Flexible connections would, therefore, require transparent and credible information on constraint patterns, alongside consideration of the impacts of different connection types on competition and investor confidence.

The viability of a flexible connection depends on a clear understanding of when and how curtailment of the asset will occur, requiring a high degree of foresight and detailed system modelling. Without this, developers face significant uncertainty around utilisation and revenues. This uncertainty would likely significantly impact the ability to secure investment and long-term structures to leverage lower project finance rates.

Q20: What role, if any, should there be for an intrazonal locational charge?

Because spare capacity exists within zones and SSEP zones are large, transmission constraints and spare capacity may vary significantly within zones and across zones. Without intrazonal signals, all projects in one zone would face the same charge, which may not incentivise the most efficient siting within zone. Intrazonal charges would make sense if zones were large and material variations in network conditions exist within the zone. Conversely, the introduction of intrazonal charges could result in less alignment with the SSEP and the options set out by DESNZ in the RNP Delivery Plan.

Rather than intrazonal TNUoS charges, which would vary in complexity depending on the option selected, using deeper connection charges to signal within-zone costs may be a potential avenue to address this, as these charges would reflect site-specific works required as well as the proportionate share of wider zone reinforcement.

A specific concern regarding zone design in Scotland is that the current proposal to move from 12 TNUoS zones in Scotland to 4 SSEP zones represents a significant reduction in granularity. This could obscure material variation in network conditions within Scottish zones.

Q21: What role, if any, do you see for deeper connection charges as a tool to influence intrazonal siting decisions?

Deeper connection charges would be appropriate as one of a range of tools for intrazonal signals, as fixed signals, set at connection offer and fixed for the lifetime of the asset, which would provide stability for developers. This would be beneficial for developers comparing locations and seeing cost differences, which could also encourage a more efficient siting. Because charges are fixed, these would provide stability for long-term investment and could be complementary to interzonal TNUoS charges without duplication.

To reduce first-mover disadvantage, which may encourage market participants to wait for others to fund infrastructure, options could be reviewed for a form of refund mechanism for transitional protections, among alternative solutions. The practicality of such a solution would be challenging, and this would need to be considered in the broader context of reforms to connection processes, and may be a more appropriate measure for connection charges than for broader network charges.

Some members would support Intrazonal charges continuing to be provided by the Local Circuit charge, fixed in an equivalent way to the fixed charge approach suggested above for interzonal charges.

It is important to note that deeper connection charges will not be appropriate if these result in unacceptably high connection costs that act as a fundamental barrier to entry. The impact on investors, developers, and generators of different levels of connection charge should be closely considered before implementation.

In addition to connection charge depth, we encourage Ofgem to consider 'local' sharing arrangements. These relate to how the costs of 'local' shared assets are allocated. For instance, under the CUSC, when multiple users are connected to the same transmission substation, the shared connection assets are classified as 'infrastructure', and their costs are socialised via TNUoS. As a result, customers are increasingly not being charged for the costs of their 'local' shared assets.

Q22: How should local circuit costs be recovered in the future?

Local circuit costs for generators should provide an effective locational signal that users can usefully respond to. These costs should not be treated as revenue collection, as this would impact on the usefulness and efficiency of these as a locational signal.

Q23: Would you expect the benefit of a more efficient locational siting incentive to justify the complexity of introducing an intrazonal use of system charge?

A new methodology for intrazonal Use of System charges would not be justified, given complexity compared to modest efficiency gains. Existing charges, such as Local Circuit costs, or other metric-based charges could be used in place of an additional charge. The complexity of any such approach would have to be carefully mitigated to ensure imbalances are avoided.

Q24: Which, if any, of the charging reform options discussed in Chapter 3 could be suitable to provide an intrazonal charge, and why?

Option A would already deliver such a charge, and would, along with Option B, be the most straightforward to implement, and potentially the most cost-reflective approach to this function.

Q25: What is the appropriate balance between connection charges and ongoing use of system charges in achieving efficient investment and siting decisions within SSEP zones?

Connection charges could continue to apply as shallow charges if combined with appropriate system charges. The approach to fixed use of system charges for both intrazonal and interzonal charges will be critical to the effectiveness of alignment between connection and system charges.

Q26: How can charges be applied to improve the long-term stability and predictability of transmission charges, while ensuring charges appropriately reflect underlying system costs and a fair risk allocation?

Some members support the proposal that charges be fixed against projected costs at the “point of competition” and for the duration of the economic life of an asset. This approach would enable generators to effectively respond by pricing future costs into their bid prices for competitive auctions. By contrast, users cannot usefully respond to unexpected changes in charges after their point of competition.

A clear definition of what the ‘economic life’ of an asset is must be established before this approach could be pursued. Assets will make additional commercial and investment decisions over the operational life of an asset, including the potential to expand the site or to extend the asset life through refurbishment. Some members support fixing charges for the extent of a contract, for example with the length of a CfD, while others support fixing for the entire operational life of the original asset. In either case, additional network signals could be effectively used again to inform further commercial and investment decisions.

Allowing developers to lock-in charges ahead of Final Investment Decision (FID) or at the point of competition, which may be ahead of FID, would require improvements to NESO projections and forecasting capabilities.

The approach could be applied within a non-mandatory framework that enables developers to elect which option (lifetime, contract-term, or other set term) they prefer based on their risk tolerance. There is an inherent risk that this would result in developers establishing their own forecasts over the NESO projections to enable them to gamble on whether the charge will increase or decrease.

As a result of charge-fixing, a developer would know their long-term cost exposure and can model more accurately. It would also reduce risk premiums included in bids and would support SSEP alignment if charges are predictable, as developers would respond to signals whilst creating a new regime that does not create stranded assets.

The tension between accuracy and predictability is one this proposal should aim to address in full. As GB shifts towards a more centralised, strategic approach to energy system planning with multi-year investment plans, this tension should lessen as network charges reflect expected future network build, enabling close coordination between the needed improved predictability of network charges and ensuring the cost of network build-out is correctly apportioned and recovered. Network charges should, in theory, become more predictable, and possibly less volatile, over time, improving investment certainty. Any deviation from the correct apportioning of charges over time should become smaller as central planning becomes more embedded in long-term infrastructure plans.

Charges should be fixed before FID, and/or at the point of competition, as cost structure is known, as well as financial terms being locked in, whilst regulatory permissions would have been substantially secured, and the cost of associated grid infrastructure would also be known. The duration of the fixed-price period would need to be set to maximise certainty so that developers can plan full asset life and avoid regular resets.

The most significant potential for variation would be in the different ways that fixed charges are applied based on technology and market participation. Some considerations that should inform the approach are as follows. There is no consensus across the industry regarding how fixed charges could be implemented, but the majority of Energy UK members recognise the potential benefits of such an approach.

Legacy generators made a one-time investment decision in the past, so they do not compete with new generators for investment/closure. These generators are already facing volatility in TNUoS charges in their ongoing operations and, as such, Ofgem should provide certainty for the immediate future rather than wait for the new arrangements to be finalised and implemented. Predictability ahead of an investment decision means providing a signal for a long-term fixed based on what they could have reasonably expected at the time of their historical investment decision.

Annually competing generators make annual investment decisions, competing between existing and new generation for investment and closure decisions in the Capacity Mechanism. Both existing and new generators should be exposed to the same latest price signal every year to ensure a level playing field. These signals should be set out with enough advance notice to take this into account in commercial contracts. This may require four years' advance notice to inform bids for Capacity Mechanism T-4, or could be a fixed price offered for those who succeed in securing a longer 15-year contract.

Transitional generators required for Clean Power by 2030 (CP30) but not yet energised will make investment decisions before the new arrangements are implemented, often competing in allocation rounds and other tenders ahead of 2030. These generators may benefit from a long-term fixed charge ahead of their one-time investment decision. These developers need certainty now, and cannot afford to wait for Ofgem's reformed TNUoS from 2029. A modified TNUoS aligned with the current incremental cost-reflective methodology, predictable at the point of investment, would be beneficial in the intermediate term ahead of full reform implementation.

New generators entering the market after the implementation of reforms will compete with each other for investment once. Providing a long-term fixed charge based on new arrangements and known at the point of that one-time investment decision would be critical. Ofgem should ensure that the review of future charges is holistic, robust, and effective, and apply this to new investment decisions after the point of implementation.

Q27: What factors should be considered when determining the appropriate representation of the network from which to derive charges?

Energy UK broadly supports the principle of setting network charges based on the planned future network as determined by the SSEP and CSNP. This will provide a long-term investment signal, given the typically longer lead times for network infrastructure compared to generation. Any delay to network delivery outside of generator/developer control should not result in significant windfalls or losses to generators/developers.

Q28. How can locational charging best reflect technology-specific differences?

Locational charging should be implemented in a way that considers and reflects the variation in technology types and aligns with the approach set out by the SSEP. Charges should reflect the realities of technical capabilities, locational variations, and commercial viability.

More geographically flexible technologies like BESS will be better able to react to locational signals, if these are set out in advance of investment decisions. Conversely, site-specific technologies like hydro or tidal have limited flexibility because their location is non-negotiable. Applying bespoke charges to these constrained assets would ensure the framework reflects technical reality rather than penalising technologies for geographic requirements they cannot change.

For offshore wind, for example, location is substantially driven by seabed leasing arrangements and wind resource quality, and these projects are already exposed to high costs from platforms, cables and OFTO charges, areas Ofgem has not reviewed in this Call for Input. These factors must be considered in the context of the SSEP, aligning price signals with realistic technological restrictions.

Consideration of co-location and coordinated connections is also necessary, aligning price signals with anticipated changes in demand (based on actual demand connection applications), timelines for reinforcement under the CSNP, and the impacts of on-site flexible assets. As stated in relation to energy storage, signals for siting should reflect the operational reality and whole-system impacts of the asset, with clear operational signals sent by markets and other available levers.

Q29. In areas where adding generation reduces the need for additional transmission infrastructure, should network charge credits continue to apply under a reformed framework? Is it appropriate these charges are paid for by final demand?

A key consideration in determining the funding of network charge credits would be the fairness and distribution of costs across generators and demand users.

The primary question will be whether credits accurately reflect savings in network reinforcement that the credited generation genuinely delivers. So long as the regime is designed to accurately reflect these savings, a cap may not be necessary. If credits are accurately cost-reflective, there is no inherent need to limit them.

Q30. If network charge credits were to continue in a reformed framework, how should they be used to provide an effective and proportionate locational signal?

To provide an effective and proportionate locational signal, network charge credits should be linked to the SSEP. By rewarding projects that meet specific regional technology needs, the system would ensure that financial incentives are directly working toward national infrastructure goals rather than functioning as a blanket subsidy.

This approach would create a more nuanced price signal by balancing planning alignment with proximity to demand. For instance, while SSEP-aligned projects receive credits, generation in "non-aligned" or remote locations would face charges that reflect the higher cost of transmission. The primary advantage would be the elimination of contradictions between central planning and economic signals, though it may introduce significant governance complexity.

On governance, determining SSEP alignment for every specific location would require a robust regulatory framework to manage the reduced eligibility for credits and resulting impact on project viability.

The competition and fairness elements of the approach must be fully explored and robustly analysed in developing potential approaches to charge credits.

Q31. Should flexible connection offers be used to manage the possibility of connections in advance of (or in addition to) planned capacity as a backstop complementary measure?

Curtailed connections are a stopgap solution that can enable more assets to connect ahead of reinforcement, but they should never be deemed an ideal outcome under NESO or network approaches or incentives.

Non-firm connections are not a permanent solution to the fundamental underinvestment seen in network infrastructure over recent decades, and should be a temporary measure that requires networks to resolve the issue within a set time and under set conditions.

Flexible connection offers could be utilised as a backstop mechanism to manage capacity that exceeds the targets set by the SSEP. Under this framework, projects that align with regional targets receive firm, non-curtailable access, while any development exceeding those targets would be offered flexible access. This would allow for faster grid connections and avoid forcing planners to overbuild infrastructure for speculative projects, as these "above-plan" assets can be curtailed during periods of congestion to protect the integrity of the firm-access projects.

The implementation of these flexible offers would require a clear framework to manage developer risk and operational complexity. Eligibility would be restricted to technically feasible projects that explicitly agree to curtailment terms, which should be time-limited, before a project must be upgraded by the network to firm status. Networks would need to be held to account for ensuring the accuracy of this timeframe, and for setting out clear terms, including detailing the curtailment impacts on the customer ahead of time. Networks will also need to be held to account for delivering the required network upgrades in line with the end of the arrangement.

To balance the risk of curtailment, financial incentives such as lower connection charges or partial refunds for significant curtailment could be introduced. However, NESO must strictly monitor these connections to ensure that above-plan generation does not drive a material increase in national constraint costs.

An approach whereby some of the requested capacity from a project is firm, with the remaining being flexible, could be encouraged where network reinforcements are ongoing, as long as that reinforcement would allow for a removal of the restriction. This would ensure that the developer knows that at any moment in time of operation, it can expect to export a certain minimum amount of power, thereby further reducing risks for the developer.

A hybrid approach could provide maximum flexibility while maintaining a strong locational signal. While speculative above-plan projects should opt for flexible access with its inherent curtailment risks, projects that represent a strategic government priority, even if above the original plan, could be offered firm access in exchange for higher charges. This tiered system would ensure that standard developments remain within planned limits, while developers with higher risk tolerances or strategic importance can still connect, provided they internalise the additional infrastructure or operational costs they impose on the network.

Q32. If projects are, under limited circumstances, permitted to connect above the planned capacity in a zone, to what extent should deeper connection charges be used to recover any additional network reinforcement costs they may trigger?

Q33. Under what circumstances do you see a need for introducing LAT arrangements? Do you agree with our rationale for the potential introduction of such arrangements?

LAT arrangements will be essential given the scale of potential charging reform. Ofgem must pursue arrangements for transitional assets urgently to ensure that developers bidding into upcoming CM and CfD auctions are able to reflect the cost of network charges within their bids. There is a clear and escalating risk that a lack of transitional arrangements will result in projects including a significant risk premium in bids, increasing costs for consumers. Ofgem and the Government must move faster to resolve uncertainty if they wish to avoid these additional costs for consumers.

A reformed TNUoS could be very different to the current status quo, with Options B/C/D/E leading to charges that could be far higher or lower depending on location.

For existing assets that made investment decisions under the old charging regime, their inability to relocate in response to new charges and the risk of unintended cost shocks, windfalls, or stranded assets warrant these arrangements. Any sudden, significant change would impact investor confidence across the market. If LAT generators are not treated appropriately, this will increase the perception of regulatory risk for those investing in GB, increasing the cost of capital and increasing the cost of new investments for GB consumers. Such price shocks should be avoided for the sake of all consumers.

If new generators have their charges fixed at the point of competition, then LAT generators may argue that they should likewise have their charges fixed. This may be most appropriately set at a level consistent with their historical point of competition. This approach could, however, result in windfall gains for existing developers, at the cost of consumers.

Ofgem should consider options for fixing charges for existing operators, from the point of implementation forward, alongside wider actions to address the current volatility of TNUoS charges in the immediate future.

For all LAT assets, action is needed urgently to address the volatility and wider impacts of TNUoS ahead of the implementation of full reforms.

Q34. Can you provide details and/or information on how investment decisions have been made to date and what factors or assumptions regarding TNUoS charging were taken into account?

A combination of official forecasts, internal modelling, and estimates provided by third-party data providers is used in current investment decisions.

Q35. Do you agree with these principles for LAT arrangements? Are there any which we are missing?

Yes, Energy UK broadly agrees with the principles set out. The importance of reducing costs for consumers should be emphasised throughout the development and implementation of the approach.

The emphasis on stability, predictability, simplicity and appropriate risk allocation for assets affected by the transition to reformed locational charging is welcome. These principles appropriately recognise that LAT arrangements should protect investments that have already taken FID based on the existing charging framework, and support investor confidence during a period of significant regulatory change.

Clear communication, administrative simplicity and avoidance of unnecessary disruption are critical for long-lived generation assets operating under fixed contractual and financing structures.

LAT arrangements should avoid leaving consumers worse off overall. Retrospective changes to charging risk for sunk assets could increase financing costs and undermine investor confidence, which may ultimately feed through to higher costs for consumers. As with network investment frameworks, short-term bill impacts should be appropriately balanced against long-term system affordability.

More clarity is required regarding the principle of maintaining a locational investment signal for transitional assets. For assets that have already taken FID and have a fixed location, it is unclear what practical purpose such a signal is intended to serve. These assets cannot respond by relocating or altering siting decisions. If the principle applies to projects that are yet to take FID but will do so before the implementation of reformed locational pricing, this should be made explicitly clear.

Q36. Do you believe determining the scope of LAT arrangements solely based on a FID cut-off date is appropriate, or should we narrow their scope based on route to market or other differentiators?

Ofgem must urgently consider the impact of TNUoS uncertainty on upcoming market and support mechanism tenders, recognising the risk premia that will be applied to bids in the upcoming rounds.

Using FID as the principal eligibility test aligns well with a core rationale for LAT arrangements: to avoid the retrospective re-risking of assets that cannot adapt their location or fundamental design in response to charging reform. Although a project's route to market can influence revenue risk, it does not reliably indicate an asset's ability to respond to locational charging signals once FID has been taken.

Alongside FID, arrangements should also consider the date of competition in CfD, CM and other relevant auctions for support scheme allocation. Generators who have not bid into or succeeded in their bids for these schemes should have arrangements based primarily on FID. Impacts on competition across technologies and between legacy, transitional, and future projects should be fully considered.

Q37. What would be the best way, in your view, for the Authority to collect and assess evidence of FID for the purposes of determining eligibility for LAT arrangements? Would it be more appropriate to use Milestones 7 and/or 8 of the connections process as the method of determining eligibility?

A FID-led eligibility framework could apply evidence of FID, as demonstrated by standard, auditable project documentation, such as formal board or investment committee approvals, binding contractual commitments (e.g. EPC contracts, major supply agreements), and evidence of committed capital expenditure.
Milestone Seven may be the most appropriate approach, particularly the inclusion of signed minutes and declaration criterion.

Q38. Should we consider differentiating between generators that are currently receiving TNUoS credits and those liable for paying TNUoS charges in determining the scope of any LAT arrangements?

Removing credits would be a significant change for many assets. Ofgem should retain a level playing field with protections applied equally for all assets.

Assets receiving credits today may still face material adverse changes under reformed charging arrangements, just as assets currently paying charges may. The relevance of LAT arrangements is linked to the inability to respond to new charging price signals, not whether the project is currently a net payer or net recipient under TNUoS.

LAT eligibility should be determined using clear, objective criteria linked to investment timelines, and applied consistently across assets, without differentiation based on whether an asset currently receives TNUoS credits or pays TNUoS charges.

Q39. Which design – parallel running, phased implementation or a fixed charging regime – could best achieve a balance of the aims for LAT arrangements?

Energy UK does not favour any single design.

Whatever approach is taken, Ofgem must look to avoid unexpected windfalls or losses across all categories of generator and developer.

The current TNUoS regime is fundamentally not fit for purpose, and as such, arrangements that extend the use of the current charging regime may embed those inefficiencies into charges over a longer timeframe.

If fixed charges are introduced, then a phased approach to implementation would enable existing assets to switch at an appropriate moment, such as the point of competition or at the point of an investment decision for refurbishment. For legacy assets, the point of competition may have passed, and it remains unclear how a phased approach would impact legacy, transitional, and future assets.

Optional fixed charges are preferred by many Energy UK members, as this would provide industry with the certainty that existing assets will not be negatively impacted, regardless of which proposal is taken forward from this Call for Input. Given that existing assets cannot respond to new locational signals, giving the option to fix charges going forward would provide generators and developers already in place or built during the transitional period with the clarity and certainty needed to continue to deliver their projects.

The question of how fixing would work for assets that currently receive TNUoS credits rather than paying charges may also warrant further consideration.

The impacts of optional fixing would need to be explored in more detail, given the potential for either those with fixed contracts or those without to gain an advantage over others, depending on how charges change over time compared to projected costs.

A parallel approach would create a permanent "two-tier" market. Keeping old projects on an outdated system indefinitely would fail to move the entire energy landscape toward more efficient and predictable price signals, leaving the most modernised parts of the grid to operate under one set of rules while everyone else follows another. There would be a potentially significant increase in the required administrative processes from such an approach, resulting in additional administrative burden for all parties.

Q40. If fixing of charges for legacy generators was deemed appropriate, which of the approaches described could achieve a balance of aims for the LAT arrangements? Are there other approaches we should consider for fixing?

If fixing charges for legacy generators was deemed the appropriate path, a fixed charging regime would be the most effective way to balance the need for investor certainty with administrative simplicity.By locking in charges at levels based on accurate projections that generators could reasonably have expected at the point of competition or point of investment, the framework would provide existing assets with a predictable cost base for their remaining operational life. This would avoid the complexity of dual-system calculations while shielding older projects from the volatility of a new, shifting methodology. There is, however, a risk of windfall gains and losses, as developers will assume TNUoS changes over time, so freezing the rate at any specific trajectory for some generators could result in winners and losers.

Fixing could, however, mitigate the risk of windfall gains and losses that could arise if future annual variable charges changed substantially compared with the level generators reasonably expected at the point of competition. A key challenge for industry is defining the most appropriate approach and calculating the appropriate level at which charges would be fixed for generators of different technologies, ages and locations.

An appropriate methodology would need to be established to determine the appropriate level at which to fix charges, setting out clear processes, sources of information, and how a range of forecasts could be used to find a weighted average.

To enhance this fixed approach, a fixed-with-indexation model could be considered. Rather than a purely static nominal figure, the charge would be fixed but adjusted annually for inflation. This would preserve the "real" value of the charge over time, ensuring that the payment remains proportionate to the original agreement while preventing it from becoming negligible due to economic shifts. This would provide a more resilient price signal that remains stable for the generator without placing an undue long-term subsidy burden on other network users.

Another alternative could be a milestone-based fixed period, which would fix the charge until a specific event occurs, such as the expiration of a project's current connection agreement or a major refurbishment. This would provide the necessary stability for the asset's current investment cycle but prevents the charge from becoming permanently disconnected from the rest of the network. It would also allow for a "fixed" status that respects the legacy nature of the project while providing an eventual pathway to system-wide consistency once and if the asset undergoes significant changes.