CORNWALL INSIGHT

CREATING CLARITY

Reform options for TNUoS and constraint management

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This paper draws on several areas of the Cornwall Insight team's expertise including:

Forecasting: Our Transmission Network Use of System (TNUoS) Charge Insight Subscription Forecast is held by many industry participants and investors as critical in determining the long-term prospects for existing and potential power generation plant. It is updated every quarter based on the latest information and our most up-to-date sector forecasts, including of wholesale power prices.

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1. Executive summary and key findings

This report explores the potential to enable the decarbonisation of the GB energy system and meeting net zero ambitions through evolutionary reforms to the transmission charging and constraint management arrangements.

Cornwall Insight is an independent energy consultant with extensive experience in market and policy analysis. This report was produced by Cornwall Insight on behalf of SSE.

As the GB electricity system decarbonises and becomes increasingly interconnected, the management of the electricity transmission network is becoming increasingly challenging. This paper sets out potential options to help address the challenges facing the electricity industry by considering reforms to the Transmission Network Use of System (TNUoS) charging arrangements and potential improvements to how constraints on the system are managed. At a time when government is considering revolutionary reforms through its Review of Electricity Market Arrangements (REMA), there is also merit in considering more evolutionary options which could deliver similarly transformational outcomes over shorter timescales and with less disruption.

The TNUoS charging approach was designed to reflect the historic GB market environment, i.e. one that was largely dominated by a small number of traditional fossil-fuelled generation assets. Some incremental improvements have been made in recent years, but there is a consensus that the approach will need to change in order to remain suitable as more and more low carbon technologies connect. The charges faced by net zero enabling technologies, such as wind generation, battery storage, and flexible demand, are often not reflective of the impact that such assets have on the system. Charges can be unpredictable, leading to uncertainty for investors, increasing costs and slowing the deployment of technologies needed to meet net zero.

Constraints on the transmission network are expected to increase significantly over the coming years. The major transmission network upgrades needed to alleviate constraints are not expected until the end of the 2020s. In the meantime, there is a pressing need to ensure that the cost of managing constraints is minimised and does not present a barrier to the electrification of demand and deployment of renewables. National Grid Electricity System Operator (ESO) is taking some steps to tackle the issue, but there are a range of evolutionary options for improving current arrangements that could be faster and easier to implement than more radical REMA reforms and deliver a similar level of sector benefits. Transformation via evolutionary change could deliver better outcomes for consumers, avoiding the risk of an investment hiatus and additional premia in costs of capital.

In this report we have assessed a number of potential options for addressing these issues. The methodology we used for this assessment is set out below in Figure 1.

Figure 1: Assessment methodology

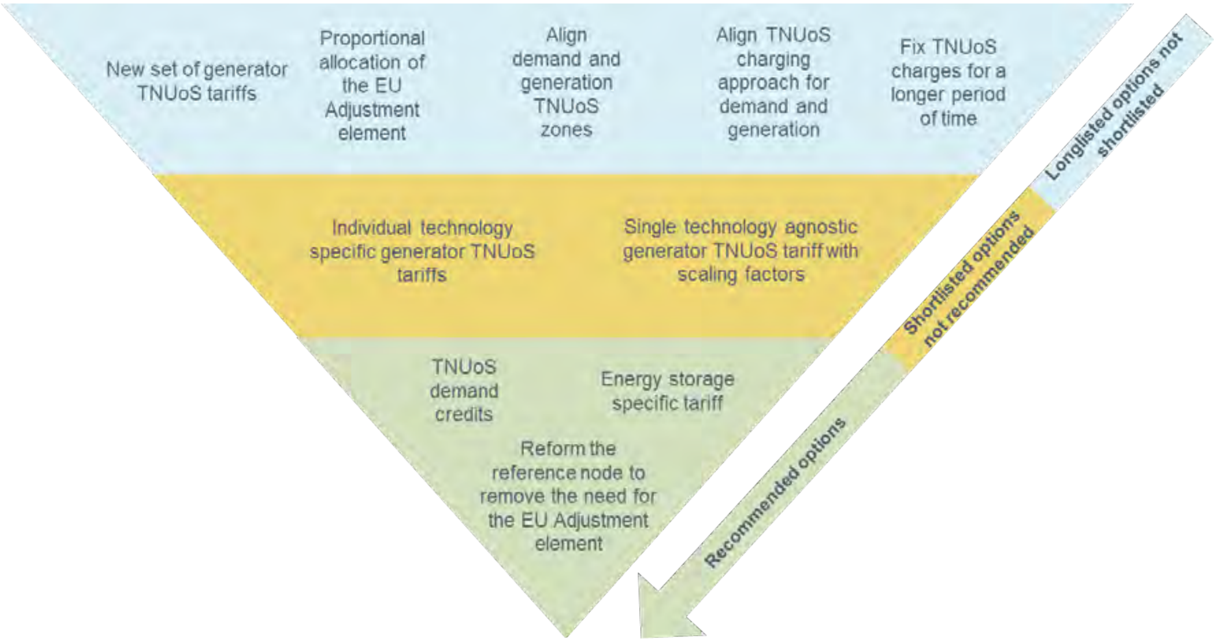
Step 1 Create an initial long list of options	We created a list of potential options for reform based on our extensive industry understanding and in-house expertise
Step 2 Create option shortlist	We assessed the full longlist based on the following criteria: does the option take into account the principles of fairness, proportionality and practicality, efficiency, and the reduction of distortions?; is the option feasible and implementable in the GB market with a reasonable timescale?; does the option adequately address the relevant problem statement?
Step 3 Detailed assessment of shortlisted options	We considered the shortlisted options under the following assessment criteria: addressing the problem statement; meeting Net Zero; investability; practicality; future proofing; acceptability; and cost reflectivity.
Step 4 Recommendation of options to be taken forward	Following our detailed scoring of each option, we ranked all of the options (TNUoS and constraint management options were considered in separate groups) to determine which should be recommended for further analysis and implementation.
Step 5 Set out delivery pathways	We produced an indicative delivery pathway for each recommended option.

Source: Cornwall Insight

We created an initial longlist of options to ensure all potential reform options were captured, before being narrowed down to a short list for further considerations and then a final set of recommendations. We did this separately for the TNUoS and constraint management reform options. The options considered at each stage are set out below in Figure 2 and Figure 3. We have further split the constraint management options into two subgroups to better reflect the differences between these:

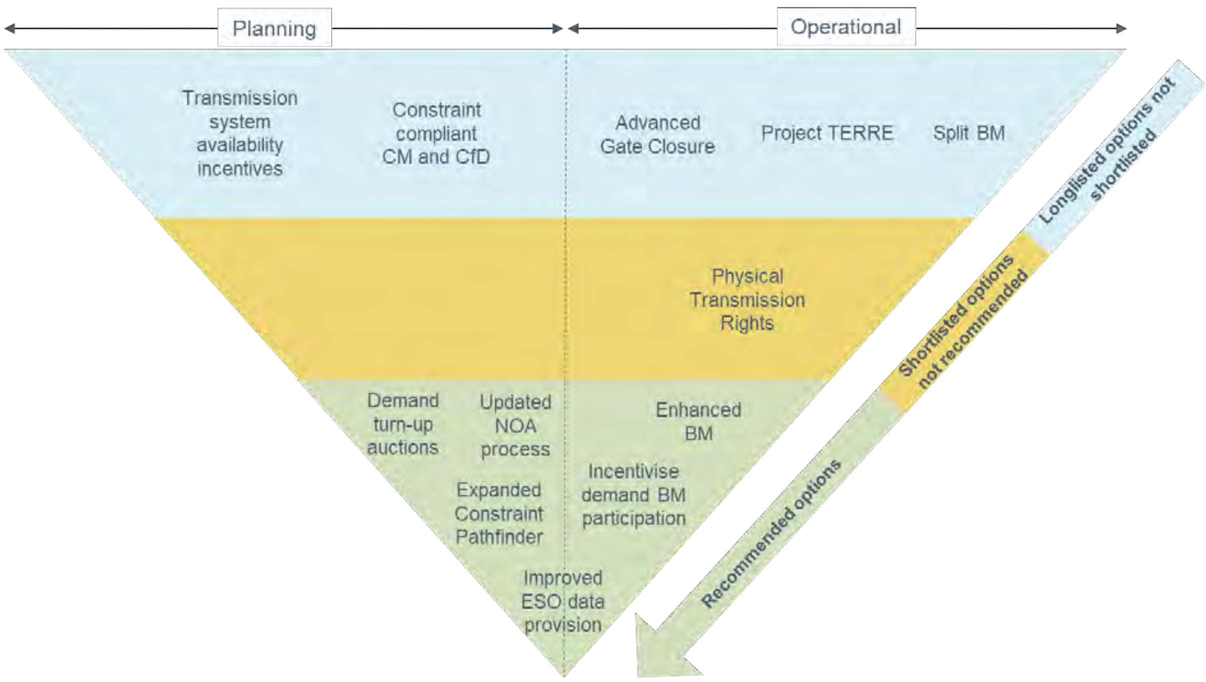
- Planning – aim to prevent constraints from occurring
- Operational – aim to better address constraints when they do occur

Figure 2: TNUoS options assessment



Source: Cornwall Insight

Figure 3: Constraint management options assessment



Source: Cornwall Insight

As these figures show, we considered a wide range of potential approaches to address TNUoS issues and constraint costs. In relation to TNUoS, we have recommend that the following options are considered further:

- **TNUoS demand credits.** This would see demand receive credits in a similar way to generation in areas where it provides benefit to the system.

- **Energy storage specific tariff.** This would make a relatively small change to current TNUoS arrangements to create a fourth tariff specifically for energy storage sites, which would be designed to be more reflective of the costs and benefits to the system of storage assets.

- **Reform the reference node to remove the need for the EU Adjustment element.** This would reform the Wider TNUoS tariff approach so that average annual generation tariffs fall within the €0-2.50/MWh limit (imposed by retained EU law) without the need for an adjustment element.

For constraint management, we recommend the following options as relatively low risk changes that could be taken forward to support constraints management at the planning stage:

- **Expand the Constraint Management Pathfinder.** Building on the success of National Grid ESO's existing constraint management activities, this would see a wider application of that approach to procuring more non-build solutions to reduce system constraints.

- **Incentivise demand BM participation**. This would see steps taken to further incentivise and support demand users to participate in the Balancing Mechanism.

- **Improved ESO data provision**. This would require the ESO to increase the provision of system information over longer-term timescales.

These could sit alongside either one or both of the following recommended options for directly impacting constraint management at the operational stage:

- **Enhanced BM.** Under this proposal BM participants would be required to provide a greater level of detail of their expected volumes over the coming 24 hours on a rolling basis.

- **Demand turn-up auctions.** This would see auctions held for demand users to gain contracts to consume energy where excess renewable power would otherwise be curtailed off to manage constraints.

We recommend considering how barriers to progressing network investment under the Network Options Assessment process could be removed as part of the constraints management options. We are aware that the ESO already considers the cost of carbon when assessing the economic benefits of network investment. This option would see the ESO also consider costs of proactive network build out and better take account of the benefits of building more network, and support delivery of Net Zero. This would also help avoid the risks and costs to customers that can follow from insufficient network build and the carbon emission consequences of network investment progression or deferral.

There are a significant number of existing industry workstreams and change process currently underway which are either looking to reform the TNUoS and constraint management regimes, or could potentially interact with changes to these regimes. Therefore it is important to consider the potential interactions between these workstreams and the recommended options for progression. This is set out in the table below.

Some of these options are similar to proposals that are already in-train via these existing processes or regulatory code modifications, and depending on the exact form of the recommended options take, it may be possible to build upon existing work. This could speed up implementation.

For other options, we believe new industry workstreams would be needed. It may be possible for some of these to be directly progressed as code modifications, but for others there are either multiple potential approaches to implementation, or unanswered questions raised as part of our initial qualitative analysis. These may benefit from additional analysis before formal code modification proposals are progressed.

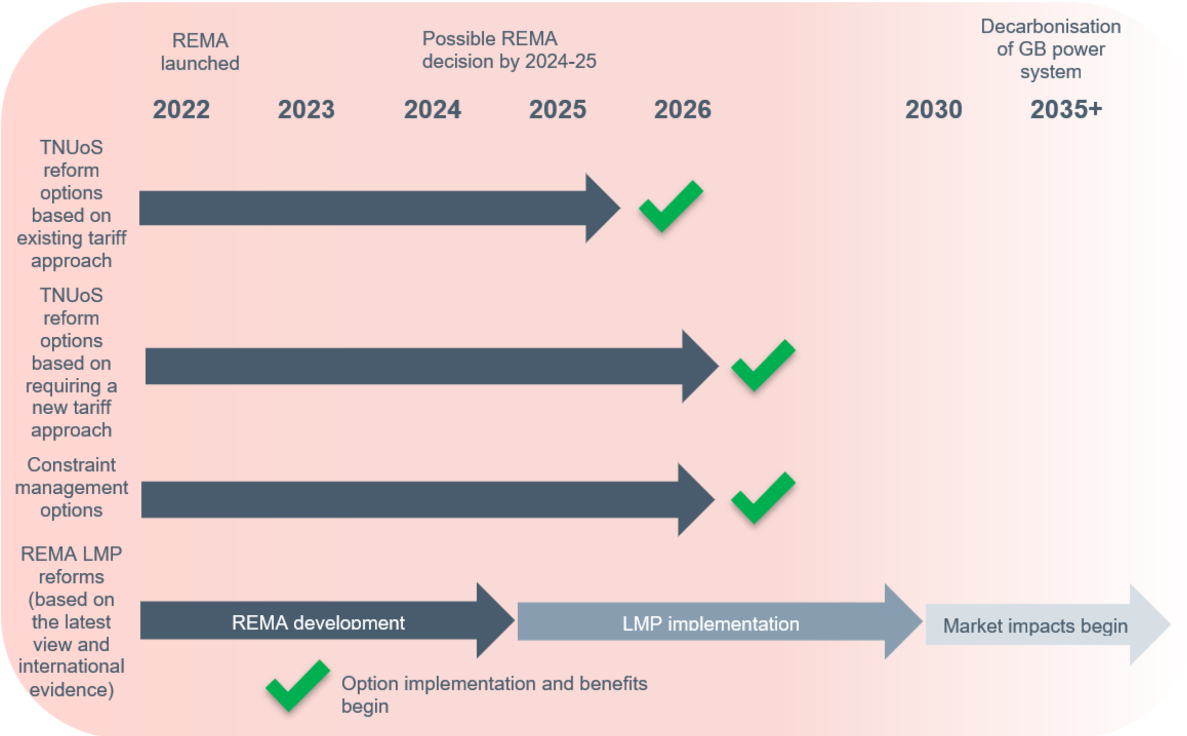
Figure 4: Interactions between recommended options and existing workstreams

	Option	TNUoS taskforce	CMP413	CMP405	CMP375 and 315	CMP 393	CMP 331	FSO consulta-tion	EBR consulta-tion	DFS	ASTI
TNUoS options	Energy storage specific tariff	Significant	Partial	Significant	Partial	Significant	Significant	None	None	None	None
	Implement TNUoS demand credits	Significant	Partial	Significant	Partial	Partial	None	Partial	None	None	Partial
	Reform the reference node to remove the need for the EU Adjustment element	Significant	Partial	Partial	Partial	None	None	None	None	None	Partial
Constraint management options	Demand turn-up auctions	None	None	Partial	None	None	None	None	None	None	None
	Expand Constraint Pathfinder	None	None	None	None	None	None	None	None	None	None
	Updated NOA process	None	None	None	None	None	None	None	None	None	Significant
	Improved ESO data provision	None	None	None	None	None	None	Significant	None	None	None
	Enhanced BM	None	None	None	None	None	None	Partial	Significant	Significant	None
	Incentivising demand BM participation	None	None	None	None	None	None	None	Partial	Significant	None
Key		None			Partial			Significant			

Source: Cornwall insight

We do not consider that the timelines for implementation or any potential interactions between options are a material challenge. While the timelines for implementation vary between options, depending on the scale of the change required, we believe that all of our recommendations could be delivered and start providing benefits sooner than a radical change such as Locational Marginal Pricing (LMP). Given the need to secure continued investment in the energy sector on an enduring basis to meet Net Zero targets, we consider that speed of implementation, and therefore impact on the system, is critical to avoid an investment hiatus. We therefore recommend these options be considered in greater detail as soon as possible and, in order to see the greatest short-term benefit of these options, they are progressed concurrently.

Figure 5: Option implementation timelines



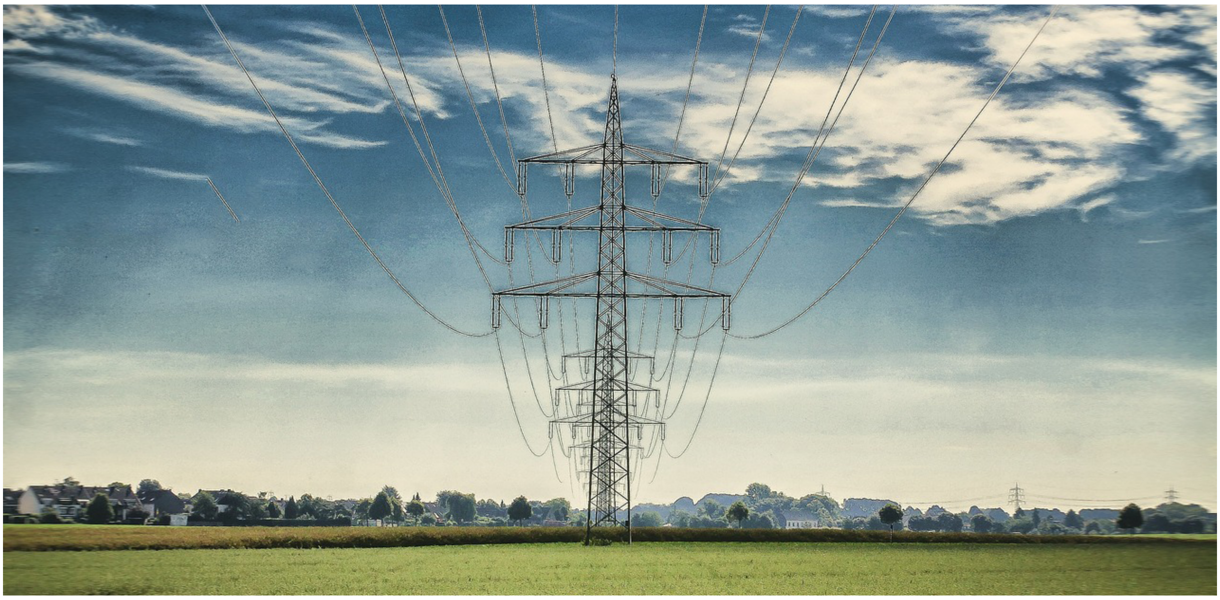
Source: Cornwall Insight

The second REMA consultation from DESNZ, announced for Autumn 2023, presents an ideal opportunity to test a baseline cost/benefit analysis of options for reform with market assumptions.

1.1 Structure of this report

The remainder of this reports sets out our approach to longlisting reform options, assessing them against defined objectives, and developing a roadmap for implementation of recommended options. It is structured as follows:

- **Section 2 - *The case for change*:** Background to the need to decarbonise the power system, and how the current TNUoS and constraint management arrangements do not adequately facilitate this.
- **Section 3 - *Methodology*:** Description of the approach to identifying and assessing reform options.
- **Section 4 - *Options for reform*:** An overview of identified TNUoS and constraint management options and rationale for shortlisting, along with an evaluation of each option. Recommended option packages are also set out.
- **Section 5 - *Roadmap for delivery*:** Discussion of necessary changes to existing arrangements, interactions with other workstreams, and indicative timelines.
- **Section 6 - *Next steps*:** High level view of the steps to be taken to implement the changes.
- **Section 7 - *Appendix*:** Additional detail on rejected longlist options, the shortlisting scoring process, and relevant ongoing workstreams.



2. The case for change

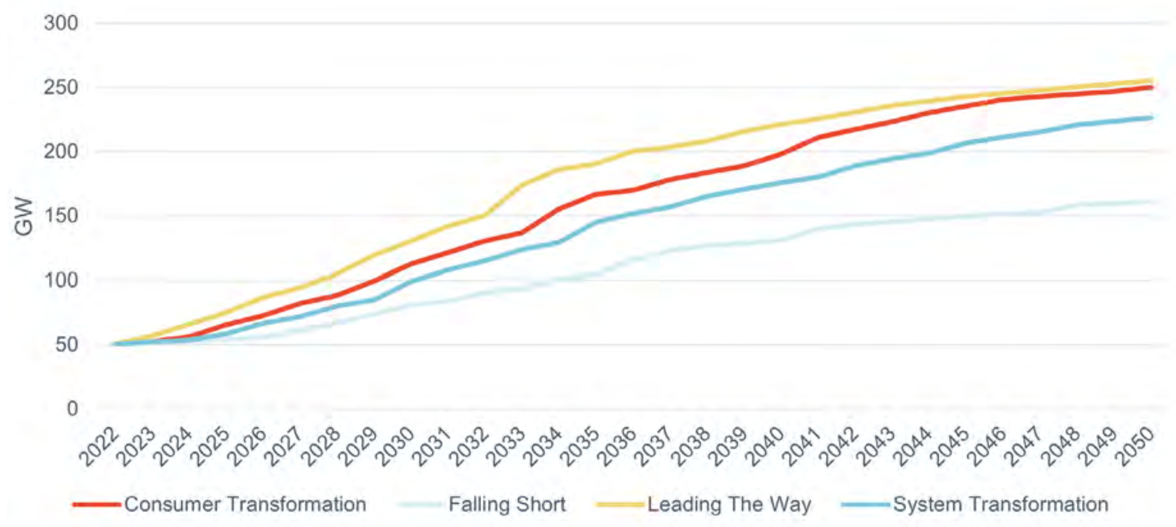
In this section we briefly describe the broad market context before introducing the context and problem statements we have sought to address on TNUoS and constraint management respectively. Finally, we consider the interaction between the problem statements defined and REMA.

2.1 Decarbonising the electricity system

On 27 June 2019, the government's Climate Change Act 2008 (2050 Target Amendment) Order 2019 to amend the Climate Change Act 2008 came into force and introduced a target for at least a 100% reduction of UK greenhouse gas (GHG) emissions by 2050. This policy target is known as a net zero target since some emissions can continue if they are offset by removal from the atmosphere and by trading in carbon units. If achieved, this target would mean the UK will end its contribution to global emissions by 2050 by effectively becoming carbon neutral. Carbon dioxide emissions from power stations have dropped by around 74% since 1990. However, to meet the UK's ambitious carbon targets, further reductions are required, and the government has committed to the electricity sector being fully decarbonised by 2035.

In order to meet decarbonisation objectives, the accelerated deployment of renewable electricity generation is needed, with the ESO's Future Energy Scenarios (FES) suggesting that over 200GW of additional renewable capacity might be required by 2050. This will require changes to how the transmission network is managed, both in terms of network charging and constraint management. Further to this change in the generation mix, electricity demand levels and usage patterns will also see significant changes. The electrification of heat and transport to decarbonise the wider economy will substantially increase electricity usage volumes, while also allowing demand to potentially become more flexible and responsive to market and price signals.

Figure 6: ESO projected installed renewable generation capacity, Future Energy Scenarios 2023



Source: Cornwall Insight and National Grid ESO

2.2 TNUoS charging

The methodology by which TNUoS charges are calculated is set out in the Connection and Use of System Code (CUSC). Generators connected to the transmission network, as well as embedded generators with a capacity above 100MW, are currently charged TNUoS on the basis of Transmission Entry Capacity (TEC), which reflects the maximum amount of power they are able to export to the system.

2.2.1 TNUoS structure

Charges comprise of Wider and Local tariff elements. Wider tariffs are intended to reflect the costs each generator imposes on the Main Interconnected Transmission System (MITS), which consists of the meshed network of 400kV and 275kV supergrid assets in GB, plus 132kV transmission assets in Scotland. Local tariffs reflect the costs of connecting to the MITS, and comprise of Local Substation tariffs (reflecting the costs of the transmission substation equipment) and Local Circuit tariffs (reflecting the costs of radial transmission assets between the substation and the generator).

Figure 7: Elements of TNUoS generation tariffs

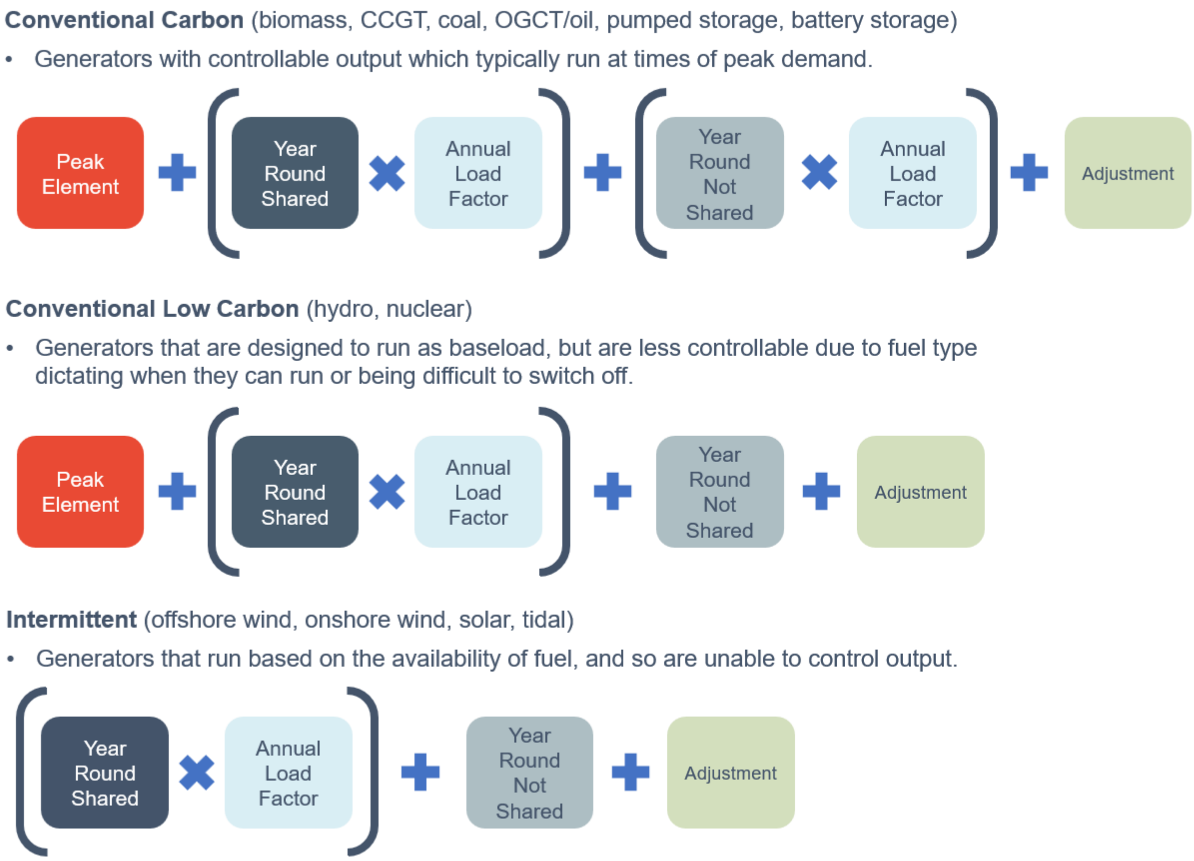
Source: Cornwall Insight and National Grid ESO

TNUoS Wider Tariffs comprise of three elements:

- The **Year Round** element takes into account the use of the system and associated reinforcement requirements across the course of the year and how this affects investment on a forward looking basis. The Year Round component is derived from the Economy Criterion as set out in the Security and Quality of Supply Standard (SQSS), which determines how the costs of investment in the transmission system should be balanced against the costs of constraints, in order to accommodate a high output from intermittent generation. It is split into a Year Round Shared element and a Year Round Not Shared element.
    - The Year Round Shared element, reflects the ability of generators to share transmission infrastructure shared with other users. It is adjusted by the generator's average Annual Load Factor over the previous five years (ignoring the highest and lowest year) to reflect the generator's impact on investment requirements.
    - The Year Round Not Shared element is used to reflect that more investment will be required for areas with a high concentration of low carbon generation due to the higher likelihood of generation occurring at the same time, leading to higher constraint costs. This element only applies where the proportion of low carbon generation in an area exceeds 50%, and is not affected by Annual Load Factor for Conventional Low Carbon and Intermittent generators. However, for Conventional Carbon generation, the Year Round Not Shared element is multiplied by the Annual Load Factor.
- The **Peak Security** element reflects the impact that the generator has on the forward-looking investment needed to ensure that peak demand can be securely met without reliance on intermittent generation and interconnection. It does not apply to Intermittent generation.
- The **Adjustment** element which is used to ensure compliance with the legal requirement for average annual generator TNUoS charges to fall within €0-2.50/MWh. This limit was introduced by the European Commission in order to facilitate a more level playing field between member states and facilitate fair cross-border trading. The arrangements were adopted into UK legislation post Brexit.

Three classifications of generator are used for the purpose of TNUoS charging, and each face different TNUoS Wider Tariff elements, as shown below.

Figure 8: Elements of TNUoS Wider Tariffs and applicability to generation types



Source: Cornwall Insight and National Grid ESO

This approach was initially introduced through CUSC Modification Proposal 213 (CMP213) as part of Project TransmiT, which saw Intermittent and Conventional classifications in place from the April 2016 charging year. The Conventional Low Carbon classification was introduced from April 2018 under modification CMP268. The intention of Project TransmiT was to move to TNUoS arrangements that better reflect the growth of low carbon generation. Ahead of the launch of the Network Access and Forward Looking Charges Significant Code Review (the "Access SCR") in 2018, Ofgem said it would not be considering a wider review of forward-looking TNUoS charges due to the recency of Project TransmiT. However, in its minded-to position on the Access SCR in June 2021, Ofgem said that there was increasing evidence of the need for a wider review due to certain TNUoS issues becoming more prominent as the energy landscape evolved. Later in the year it launched a call for evidence on the extent to which TNUoS reform was needed, followed by the launch of a TNUoS Task Force, the work of which is currently ongoing. Ofgem recently published an open letter on strategic charging reform which continues to ask sweeping questions about the future of TNUoS charges with no definitive conclusions

2.2.2 Link to transmission network planning

There are strong links between the TNUoS charging methodology and the SQSS. TNUoS charging treats generating technologies in broadly the same way as SQSS. This means the way users are charged for using the network via TNUoS aligns with how the system is planned via the SQSS. Like TNUoS, the SQSS was developed at a time when the system was dominated by on-demand generation, and does not accurately reflect new flexible technologies such as storage.

2.2.3 Operational vs investment signals

Generator TNUoS is charged on a £/kW basis so does not provide a dispatch signal, which instead is provided through the wholesale energy market, Balancing Mechanism and ancillary services. Going forward, the existing arrangement where a network charge signal gives a long-run location signal with short-run operational signals delivered through wholesale energy and flexibility markets is likely to continue to have merit.

However, the unpredictability and volatility of TNUoS charges is an issue. TNUoS charges do not provide a sufficiently useful investment signal because investors cannot accurately predict them at the time they make commercial decisions, so cannot effectively respond to them. This unpredictability also increases investor risk, which increases the cost of capital, which in turn tends to increase the cost to customers and disincentivise investment in generation, especially renewables. TNUoS currently provides a signal for the siting of generation, but as tariffs have the potential to significantly change over the course of an asset's lifetime, this has limited value as the generator will be unable to take action once it is connected. Renewable generators may have less opportunity to recover these costs elsewhere, e.g. via the Capacity Market, than conventional generators. Some stakeholders have highlighted that it will be hard to achieve net zero as the TNUoS zones with the highest charges are the most suitable for the deployment of renewables. Under current market arrangements, renewables will typically locate near to natural resources such as wind, and where suitable land is available. However, these tend to be areas of lower demand, and as such TNUoS charges are typically higher.

2.2.4 TNUoS problem statement

TNUoS reform is needed as the current approach is outdated. While it can be argued that current TNUoS arrangements result in appropriate charges for traditional on-demand generation, they do not deal effectively with renewable technologies. They also fail to send adequate investment signals for flexible assets such as storage and hydrogen production, and for co-located assets, all of which are likely to be needed in a net zero energy system.

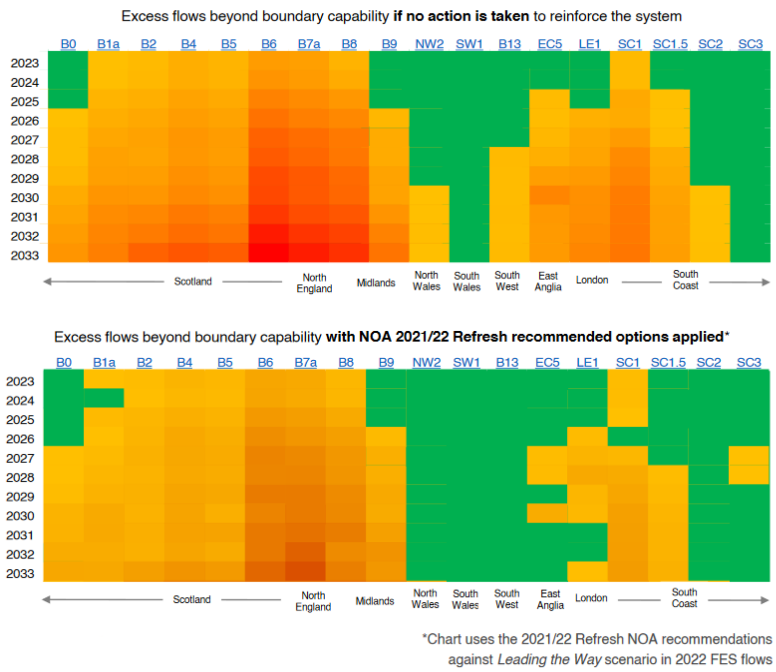
2.3 Constraint management

Currently, there is a regional imbalance between generation capacity and demand, with new generation capacity skewed to the north, and the majority of demand growth in the south. Constraints arise where the transmission network is unable to transmit electricity from the source of generation to the location of demand. This typically occurs where local generation outstrips demand in a particular area, and the capacity of the network is unable to flow the excess power to other areas. Where constraints occur, The ESO takes actions to ensure that the system remains operationally safe, typically limiting the output of generators on the exporting side of the constraint, and offsetting this by instructing generation on the importing side which would otherwise be out of economic merit to increase output. The ESO uses network investment to proactively avoid constraints arising, as well as the Balancing Mechanism (BM) to manage existing constraints.

2.3.1 Constraint hotspots

As shown in Figure 9, the excess flows are currently most prevalent at the B6 boundary, which roughly runs along the border between Scotland and England, as well as the B7a boundary that runs across northern England. Excess flows are expected to increase during the 2020s as more offshore wind connects to the north of those boundaries ahead of network reinforcement, with other boundaries also becoming increasingly constrained. Constraint costs are difficult to predict, and the ESO takes these uncertainties into account as part of its Network Options Assessment (NOA) process, which considers constraints under the different Future Energy Scenarios.

Figure 9: Impact of Network Options Assessment reinforcement actions on constraints



Source: [National Grid ESO]

2.3.2 Ongoing reform

A long-term solution to constraints would be to increase the capacity of the network should be increased to overcome constraint issues (this is the underlying logic of the SQSS upon which the year round tariffs are built). But the length of time and cost of new network build also necessitates consideration of other options.

In recent years the ESO has taken a number of additional steps to address constraints. These include the Constraint Management Pathfinder, targeted at particular areas of the network such as the B6 boundary between England and Scotland. Under the B6 Pathfinder, the ESO has procured transmission-connected generation to connect to the Anglo-Scottish Commercial Intertrip Scheme and be disconnected within 150ms of a network fault. Without this provision, ESO would be required to maintain redundancy on the network to avoid catastrophic failure in the case of a fault. Hence the role of this pathfinder is to allow ESO to more fully utilise the physical network capacity available. The ESO has also set out plans to create a similar Constraint Management Intertrip Service for the East Anglian EC5 boundary, with the service intended to begin in 2025. A Local Constraint Market has also been developed to procure generation turn down or demand turn-up services on a day-ahead basis, providing an alternative to the BM.

2.3.3 Constraint management problem statement

Constraint costs are already high and are increasing, with this trend expected to continue if network reinforcement fails to keep up with the amount of generation needed to meet net zero ambitions. Constraint costs are currently forecast to increase significantly in the 2020s and not reduce until at least 2030 as major transmission investments come online. In the meantime, action must be taken to more efficiently manage constraint costs.

2.4 Review of Electricity Market Arrangements (REMA)

The government is currently undertaking its wider Review of Electricity Market Arrangements (REMA). This workstream could result in significant changes for the GB energy system. The initial consultation on REMA was published in July 2022, with further updates expected in 2023. The options for reform cover all non-retail electricity markets, including the wholesale market, Balancing Mechanism and ancillary services, as well as policies that impact these, such as the Contracts for Difference (CfD) scheme and the Capacity Market. Notably, there is a focus on considering options that may improve signals relating to locational issues at both investment and operational timescales, with potential options including:

- Introducing locational marginal pricing - either zonal or nodal. This would see wholesale prices vary depending on location, with a broad expectation that higher prices would be seen in areas of relatively high demand and relatively low generation.
- Reorienting the wholesale market around local markets, either through new local market structures or locational imbalance pricing. Variations include separate pool, balancing, and ancillary services markets at each node (where generation, supply, interconnector, or distribution system connects to the transmission system), alongside the national wholesale market, as well as local imbalance pricing, and incentives for suppliers to source power locally rather than nationally.
- Moving to central dispatch, which would see participants notifying the system operator of their availability through day ahead and intra-day markets, before the system operator schedules generation taking into account a range of factors such as constraints. This could, in effect, lengthen the gate closure interval to the day ahead stage.
- Shortening the settlement period, to allow prices to be more reflective of actual market conditions. This is intended to incentivise more frequent responses to the state of the system by generation and demand.
- Reducing the gate close interval, which could allow generators to make their final positions more accurate, therefore reducing the need for balancing actions.
- Reforming the Balancing Mechanism to address rising costs, through the introduction of price caps or restrictions on excessive offer prices. Other

options include limits on generators amending their schedule at short notice, strengthened locational signals, or changes to the bidding structure.

- Splitting the wholesale market into separate markets for variable and firm power, which is primarily proposed as a solution to price cannibalisation, and the resulting price volatility. Part of this is intended to provide stronger signals for demand-side flexibility.

- Moving the wholesale market to pay-as-bid rather than existing pay-as-clear pricing, where participants would receive the price of their bids/offers rather than the bid of the highest priced participant.

These would represent revolutionary changes to the energy system that significantly depart from existing arrangements. Historically these types of changes have taken significant time to implement and resulted in periods of market uncertainty. This could increase the risk of the UK failing to achieve net zero by 2050. Therefore, in the following sections we have aimed to set out alternative evolutionary options for reform that would address the problem statements. We believe these options would result in similar benefits, but be more easily and quickly implemented.

3. Methodology

In this section we have set out the process we followed in producing this analysis. Each of the areas are discussed in greater detail in subsequent sections. We undertook a five-step process as set out in the figure below.

Figure 10: Assessment methodology

Step 1 Create an initial long list of options	We created a list of potential options for reform based on our extensive industry understanding and in-house expertise
Step 2 Shortlist the options	We assessed the full longlist based on the following criteria: does the option take into account the principles of fairness, proportionality and practicality, efficiency, and the reduction of distortions?; is the option feasible and implementable in the GB market with a reasonable timescale?; does the option adequately address the relevant problem statement?
Step 3 Detailed assessment of shortlisted options	We considered the shortlisted options under the following assessment criteria: addressing the problem statement; meeting Net Zero; investability; practicality; future proofing; acceptability; and cost reflectivity
Step 4 Recommendation of options to be taken forward	Following our detailed scoring of each option, we ranked all of the options (TNUoS and constraint management options were considered in separate groups) to determine which should be recommended for further analysis and implementation.
Step 5 Set out delivery pathways	We produced an indicative delivery pathway for each recommended option.

Source: Cornwall Insight

Step 1: Create an initial longlist of options

We created an initial longlist of potential options for reform influenced by our extensive industry understanding and in-house expertise. At this stage of the process we were looking to create a relatively wide-ranging set of potential options and so consciously did not attempt to pre-judge or pre-determine the outcome of the following two assessment phases.

Details of the options considered at this stage that did not pass the shortlisting process are included in the appendix.

Step 2: Create option shortlist

We assessed the full longlist based on the following criteria:

- Does the option take into account the principles of fairness, proportionality and practicality, efficiency, and the reduction of distortions? These are aligned with principles that Ofgem has previously set out when assessing network charging reform
- Is the option feasible and implementable in the GB market with a reasonable timescale?

- Does the option adequately address the relevant problem statement?

For each of these criteria we awarded a score based on the below definitions:

- 0: Fails to deliver
- 1: Limited delivery of requirements
- 2: Partially meets requirements
- 3: Mostly meets requirements

We used an overall score of six as the threshold for shortlisting. However, anything that scored a zero on any of the criteria (i.e. failure to deliver) was automatically rejected from the shortlist, regardless of its overall score.

Scores from the shortlisting assessment are set out for each of the initial options in the appendix.

Step 3: Detailed assessment of shortlisted options

For the detailed assessment, we considered the shortlisted options under the following assessment criteria on a 1-5 scale. The following assessment criteria were equally weighted:

- **Addressing the problem statement**: Would the option help to address the mismatch between the current arrangements and the existing and future GB generation landscape?

- **Meeting Net Zero**: Would the option help to support decarbonisation objectives?

- **Investability**: Would the option maintain or increase investor appetitive in GB?

- **Practicality**: How long would the option take to implement, and what scale of change will be required from industry?

- **Future proofing**: Would the option be able to take into account future market developments?

- **Acceptability**: How acceptable would the option be for the industry?

- **Cost reflectivity**: Would the option appropriately pass on costs in a manner that reflects how the network is built and used?

A summary of the scoring criteria is below.

Figure 11: Explanation of scoring criteria

Score	1	2	3	4	5
Addressing the problem statement	Worsens the problem identified in the problem statement	Neutral or very minor impact on the problem	Slightly addresses the problem	Materially addresses the problem	Substantially addresses the problem
Meeting Net Zero	Delays or worsens the ability to deliver Net Zero	Neutral or very minor impact on delivering Net Zero	Slightly supports delivering Net Zero	Materially supports delivery of Net Zero	Substantially supports delivery of Net Zero
Investability	Reduces investability in the energy industry	Neutral or very minor impact on investability	Slightly increases investability	Materially increases investability	Substantially increases investability
Practicality	Unlikely to be implementable – not practical, no existing process for making change and no precedent	Challenging to implement – significant practicality challenges, existing process for making change but limited precedents	Possible to implement – practical, existing process for making change with various precedents	Relatively straightforward to implement – easy, well understood existing process for making change with numerous precedents	Straightforward to implement – very easy, well understood and often used process for making change with numerous precedents
Future proofing	Unlikely to be suitable for future market and network issues	Limited suitability for future market and network issues	Some suitability for future network issues, or short-to-mid time period of suitability	Expected to be broadly suitable for future market and network issues	Expected to be highly suitable for future market and network issues
Acceptability	Unlikely to be accepted by any industry parties	Expected to have significant resistance from many industry parties	Support from some industry parties with resistance from others	Significant support from most industry parties with resistance from others	Likely to be accepted by most industry parties
Cost reflectivity	Less cost reflective than the current approach	Same or similar level of cost reflectivity as the current approach	Slightly more cost reflective than the current approach	Materially more cost reflective than the current approach	Substantially more cost reflective than the current approach

Source: Cornwall Insight

We scored on an overall GB basis. Individual technologies or areas are likely to see different impacts, but for this analysis we have tried to consider the net impact or expected views of the entire industry. Technology and party specific implications could be considered in further work for recommended options.

Step 4: Recommendation of options to be taken forward

Following our detailed scoring of each option, we ranked all of the options (TNUoS and constraint management options were considered in separate groups), then produced a recommendation on those that should be progressed for further analysis and implementation.

Step 5: Set out delivery pathways for the recommended options

We produced an indicative delivery pathway for each recommended option. This included:

- Potential required changes to industry rules (codes, licences, or operational practices)
- Interactions with ongoing industry workstreams
- Indicative timelines for implementation
- Interactions with other proposed options (if any)

4. Options for reform

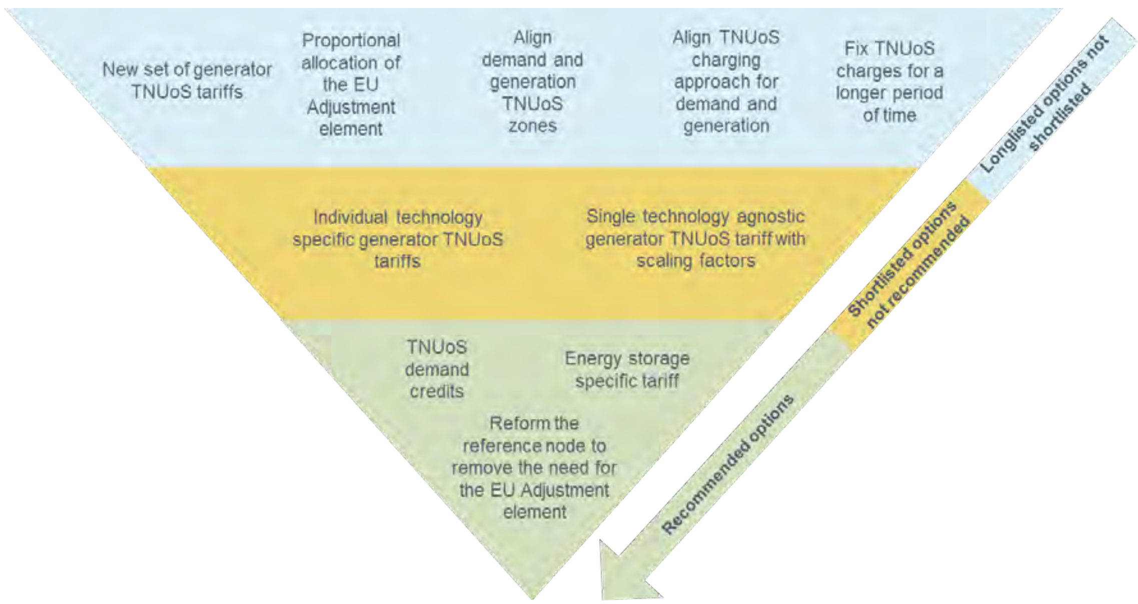
Options for reform fall into three main categories: TNUoS reform options; planning based constraint management options, which would change the ESO's planning approach; and operational based constraint options.

An overview of the longlist groupings, shortlisting and recommendations are shown in Figure 12. Where an option has not been progressed to the shortlist or final recommendation this is not intended to suggest that the option does not have potential merit, and it may still be appropriate for industry to further consider or progress these. Instead, the shortlisting and recommendation reflects the degree to which options address the specific objectives against which options were assessed for this project and the project's specific problem statement.

In the below diagrams we have set out the options that were considered at each stage:

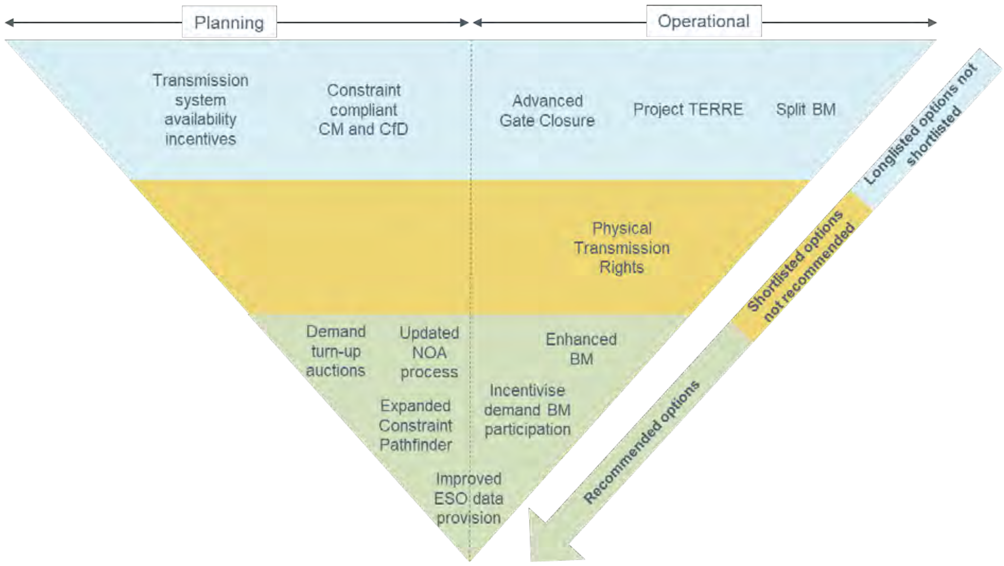
- The longlist section shows the full list of options that were considered
- The short list section shoes the list of options that made it through the initial assessment
- The final recommendations section shows which of the short listed options are recommended following the detailed assessment

Figure 12: Assessment process of TNUoS reform options



Source: Cornwall insight

Figure 13: Assessment process for constraint management reform options



Source: Cornwall Insight

The rest of this section focuses on options that were shortlisted (those shown in the yellow middle section of the above diagrams), with details of the longlisted options that did not pass the initial gating exercise provided in the appendix. Following the shortlisting exercise, five TNUoS options and seven constraint management options were identified.

4.1 Options for TNUoS reform

We shortlisted five TNUoS options, including three generator specific options, one demand option and one methodology change.

The first three options described below are the generator specific options, which have similar features and wider considerations. As described in Section 2.2, the TNUoS charging methodology currently uses three generator TNUoS tariff categories and all of these generator specific TNUoS options would see a change to these groupings, to various degrees. Due to the mutually exclusive nature of the generation options (i.e. none could be implemented alongside the others given they all propose changes to the same set of definitions) the main wider consideration is which of these options would represent the best solution.

Many of the shortlisted TNUoS options may result in the CUSC charging methodology exhibiting some divergence from the SQSS, which may indicate a need for the SQSS to be updated as well. While TNUoS currently aligns with the SQSS, neither adequately consider storage, and so modifications to both would be desirable. Aligning the two may be beneficial for cost reflectivity, but we do not believe that implementing reforms to TNUoS should be delayed or avoided because updates to SQSS may take longer. This is an area that would benefit from further consideration if any of the options that diverge from the SQSS are progressed.

The considered changes will impact the overall TNUoS tariff faced by generators and demand, to varying extents, so there may be an argument for some form of grandfathering or lead time before changes would be implemented. This may not be required but would be something we would expect to be considered in more detail later.

4.1.1 TNUoS option 1: Individual technology specific generator TNUoS tariffs (generator specific)

Shortlisted

Overview

- Each technology given its own tariff based on a combination of the existing Wider TNUoS tariff elements
- Goal: ensure all technologies face charges that are more reflective of when they export power
- **Outcome: not recommended as a storage specific TNUoS tariff was considered a better option**

Option structure

- The ESO would publish individual tariffs for each technology. We propose that these tariffs would still consist of the current underlying TNUoS tariff elements
- To ensure this remains fit for purpose as new technologies connect, a regular process for reviewing the technologies would be included
- Storage charged on the same basis as other generators (i.e. based on their expected generation impact during peak and off peak periods). However, expected demand would be considered when calculating net power flows under different system conditions. This may impact multipliers applied to the underlying tariff elements

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	Would address one of the major issues with TNUoS by factoring in the net benefit storage and other flexible generation delivers for the system. However, as an export tariff focused approach, it may not reflect storage imports which may be better reflected as a change to demand charges. There may be minimal additional value compared to the current approach if multiple technologies end up with functionally the same tariffs. Additionally, the change doesn't address the disparity between the treatment of generation and demand.	3
Meeting Net Zero	Better reflecting the benefits of different technologies on a more granular basis would mean that tariffs would change for different technology types. While the direction of change would depend on a range of factors including location, we expect that storage would face lower charges in recognition of the system benefits it can provide.	3
Investa-bility	Would not address the volatility and unpredictability of TNUoS, and so may not provide any demonstrable improvement for investors.	2
Cost reflectivity	Tariffs would be more closely aligned with the costs that different generators place on the system.	3
Practicality	The option does not represent a significant departure from the current arrangements, and so should be relatively implementable, although determining a methodology which more accurately reflects network impacts could be difficult.	3
Future proofing	By establishing a methodology for assessing individual technologies, the approach would be more future proof than the current approach, allowing for the introduction of new tariffs when new technologies wish to connect.	4
Acceptabil-ity	The option would not represent a major change, and so may be acceptable to Ofgem if adequate benefits can be demonstrated.	4
Final score		**3.14**

Wider considerations: Currently, one of the main issues identified with TNUoS charges is they do not adequately reflect the benefit that electricity storage can offer the network as a source of both demand and generation. Therefore, something that would need to be considered as part of this option is whether or not the storage tariff would need to be structured in a way that accounts for imports as well as exports. However, this may not be needed if this option were combined with some of the other options considered.

In addition, there is a question of whether this option would provide any additional value compared to the longlisted option of "new generator TNUoS tariffs", which would introduce four distinct categories based on technology type and operating profile (see Appendix for details). If, for example, multiple technologies ended up with the same tariff as each other, then this option may result in more complexity with no additional value.

4.1.2 TNUoS option 2: Single technology agnostic generator TNUoS tariff with scaling factors (generator specific)

Shortlisted

Overview

- Technology-neutral underlying tariff elements would apply for all generators, varying based on scaling factors
- As different technologies have different export profiles, this option would need to include multiple scaling factors
- Goal: more flexible application of scaling factors between different technologies to remove the arbitrary distinction between technology groups under current arrangements and create cost-reflective tariffs for all technologies
- **Outcome: Not recommended as a storage specific TNUoS tariff was considered a better option**

Option structure

- Each of the elements within the Wider TNUoS tariff faced by generators would be multiplied by an appropriate, site-specific scaling factor. For example, the Peak Element would be multiplied by a Peak Scaling Factor, which would vary based on the technology and site. A battery storage asset may need a higher Peak Scaling Factor than a solar farm in order to reflect their behaviour at times of peak demand. As system peak may move in the future as the energy market transitions towards net zero, these scaling factors could vary over time to help future proof the arrangements
- Scaling factors could be treated in the same way that Annual Load Factors (ALFs) are currently treated, whereby there are generic values for each technology that are then replaced with site specific values when there is an adequate amount of operational data
- The exact level that these scaling factors should be for each technology would require detailed further analysis to develop

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	Could be used to provide more appropriate signals for generators based on their impacts on the system. This would help to better reflect the benefits of storage. Volatility issues would not be addressed if this was a standalone change, and disparities between generation and demand would not be improved.	3
Meeting Net Zero	Accounting for technology specific differences could help to support a system with a more intermittent generation mix.	3
Investability	Introducing a single tariff may help to improve the predictability of TNUoS to some extent.	2
Practicality	While this does build on the existing TNUoS approach, there could be challenges in determining the scaling factors for each technology. This could be a complex process and one open to challenge.	3
Cost reflectivity	This would improve cost reflectivity as tariffs would be based on the impact of individual technologies on the transmission network.	4
Future proofing	The option should be relatively simple to future proof, as multipliers could be introduced or updated to account for changes.	5
Acceptability	There would be winners and losers under the approach, and the complexity of determining scaling factors may be off-putting for some.	3
Final score		**3.29**

Wider considerations: As with the technology specific tariff option discussed above, an assessment will need to be done as to whether this option would offer any additional value over an option that grouped users into different tariff classes. Any scaling of the Peak Security charge should take into account the scaling used in the SQSS, because cost reflective charges should be based on how parties cause incremental network cost, which can be different from their average use of the network. An additional consideration is whether this single tariff could or should be implemented in a way that accounts for imports, or whether it should remain a purely generation (i.e. export) focused tariff.

4.1.3 TNUoS option 3: Energy storage specific tariff (generator specific)

Recommended

Overview

- Create a fourth tariff specifically for energy storage sites, either based on a combination of the existing Wider Tariff elements, or based on a new methodology that also accounts for storage imports
- Could also be achieved via storage demand credit separate to the storage generation charge, either as a stand-alone solution for storage, or as part of the broader demand credit option, described below (option 4)
- Goal: ensure storage is adequately accounted for in TNUoS charges
- **Outcome: Recommended as an easily achievable option that would better reflect the value of storage within TNUoS charging**

Option structure

- For the purpose of this analysis, this option is based on a combination of existing tariff elements with changes made to the application of ALFs. This is to ensure the tariff remains a generation tariff, which aligns with wider treatment of storage (i.e. it is considered a generator). However, the option to treat storage under the methodology as both demand and generation is something that could be considered in further analysis
- This option would only materially impact storage assets. All non-storage generators would continue to be charged based on the current approach

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	This would help better reflect the benefits of storage on the system.	3
Meeting Net Zero	Bringing storage out of the Conventional Carbon classification provides an opportunity to create a tariff more reflective of the impact that storage can have on the system. This could provide a more appropriate signal for the storage to better incentivise deployment.	4
Investability	This is unlikely to address many of the concerns that investors have around the unpredictability of TNUoS.	3
Cost reflectivity	The option would help to improve cost reflectivity, but only for storage assets.	4
Practicality	This should be a relatively simple option to implement, with the majority of TNUoS arrangements remaining unchanged.	3
Future proofing	Introducing a single storage specific tariff may not allow for future technologies to be accounted for, but a similar approach could be repeated.	3
Acceptability	There is a recognition that the TNUoS arrangements could be improved for storage, and with limited impacts on other participants it is not expected that there would be significant opposition.	4
Final score		**3.43**

Wider considerations: There is a question of whether imported power should be considered within the same tariff as exported power. In addition, there is at the time of writing a code modification in process (CMP393) that is looking to use both imports and exports to calculate the ALF used for electricity storage sites. It is possible that a code change resulting from this modification would make the existing TNUoS tariffs more fit for purpose for storage sites, thereby reducing the potential benefits offered by this option.

4.1.4 TNUoS option 4: TNUoS demand credits (demand specific)

Recommended

Overview

- Demand would receive credits, in a similar way to current arrangements for generation, in areas where it is beneficial. This could be implemented in a number of ways:
  - Demand credits for flexible and responsive "net zero enabling demand", e.g. electrolysers, EV charging sites, and storage
  - Demand credits on a fixed £/kW per year basis for all types of demand
  - Demand credits on a volumetric time-of-use basis for all types of demand
- Goal: to incentivise demand users to locate in areas with excess renewable output, which would otherwise be constrained off
- **Outcome: Recommended as it would better align the treatment of demand and generation in relation to network charging and could incentivise the use of excess renewable generation**

Option structure

- The goal of this option is to incentivise demand users to **locate** in areas with surplus renewable output, so a dispatch signal should be avoided. We therefore propose that credits be applied on a £/kW per year basis based on connection capacity, but with credits scaled based on actual consumption during periods of renewable generation network congestion. This would align with the treatment of generator TNUoS credits and avoids demand users receiving payments without providing a corresponding benefit to the network..
- Several definitions of periods of network congestion could be chosen, e.g. peak renewable output, peak generation output, peak constraint etc. We propose this be based on peak renewable output, determined annually ex post based on consumption within a zonally varying time period. For example, a zone in North Scotland would reflect peak wind output, whereas a zone in the South West would reflect peak solar output

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	This option would help to provide a signal for the deployment of demand assets in a way that is beneficial to the system, and would better align the treatment of demand and generation. It would also help to better reflect the benefits of storage imports, and could help to address constraint costs by incentivising demand users to locate in areas of high renewable output.	4
Meeting Net Zero	The option could incentivise demand to locate close to sources of excess generation, helping to improve the business case of net zero enabling technologies such as storage and hydrogen electrolysers.	4
Investability	Providing demand credits could boost the investment signal for siting near renewables.	4
Cost reflectivity	Credits for demand would better reflect the benefits it can provide to the system.	4
Practicality	There are a number of challenges with implementing this option. These include the determination of areas that would see demand credits, and the approach to charging base either on a static basis, or dynamic, which may include assessing times of peak renewable generation and/or times when constraints are most likely.	3
Future proofing	The eligibility criteria for demand credits could evolve over time, taking into account the deployment of new technologies such as electrolysers, EV charging and heat pumps.	4
Acceptability	Historically it made sense for demand to not face TNUoS credits, however, now that the system has evolved demand may be beneficial to balancing the system and should therefore be charged/credited appropriately. There may be issues with any policy that encourages increased consumption of energy, but we expect these will be mitigatable	4
Final score		**3.86**

Wider considerations: One of the key considerations of this option is whether credits should be applied to all, or just certain types of demand users. For example, credits could be limited to demand that supports Net Zero, such as electrolysers or EV charging sites. Linked to this, consideration should be given to whether dispatchable demand should be treated differently to non-dispatchable demand. In addition, careful consideration would need to be given to the most suitable peak period, and that the scheme is structured in a way that prevents demand from benefitting from consuming power unproductively or inefficiently.

4.1.5 TNUoS option 5: Reform the reference node to remove the need for the EU Adjustment element (methodology change)

Recommended

Overview

- Update Wider TNUoS tariffs so that charges remain within the €0-2.50/MWh range without adjustment. This would largely remove the need for the EU Adjustment element, although there may still need to be small adjustments for fine tuning and reconciliation
- **Outcome: Recommended as it would provide more cost reflective locational signals through TNUoS charges**

Option structure

- A shift downwards in all generation tariffs such that total credits either fully offset total charges (i.e. net to zero) or target a net position averaging e.g. €1.25/MWh to allow an error margin within the €0-2.50/MWh range. This could be achieved by configuring the calculation of TNUoS such that the (hypothetical) point on the system where charges flip to credits (the so-called "reference node") results in the desired net revenue position. This was discussed under the Access SCR, with Ofgem considering either selecting a specific Reference Node, or moving to a "generation-weighted reference node" which could achieve this outcome

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	While the option could help to improve cost reflectivity, it is limited in aligning current arrangements with a decarbonised system that provides adequate signals for new technologies.	3
Meeting Net Zero	Better cost reflectivity would enable better investment signals for low carbon generation.	3
Investability	This would remove an element of TNUoS charges that varies significantly year-to-year, which we believe would have a slight benefit for investability	3
Cost reflectivity	Could enable more cost reflective charges to better reflect that carbon emitting generation at one location does not displace the need for network investment built to transport low-carbon generation.	4
Practicality	Changes to the Reference Node would require careful consideration of the functionality of the Transport Model.	3
Future proofing	The adjustment element is forecast to grow significantly over coming years, and will begin to dominate charges in a non-cost-reflective manner. Removing it by design will ensure this situation does not arise.	4
Acceptability	There have been significant efforts regarding how the limiting regulation is met, so Ofgem may be reluctant to look at an option that changes the compliance arrangements further.	3
Final score		**3.29**

Wider considerations: A key consideration for this option is the frequency at which the hypothetical mid-point of the system is determined. If it were done every year it would be more accurate, but would potentially make charges more volatile. Alternatively, if it were done infrequently it could result in material step changes in charges, again potentially exacerbating volatility in TNUoS charges. Alternatively, a benefit of using a pro-rata generation weighted reference node is this would avoid the need for a process of subjectively selecting a specific "mid-point" node.

4.1.6 Overall assessment of TNUoS options

Based on the detailed options assessment, three TNUoS options are recommended for further consideration.

Figure 14: Overall assessment of TNUoS options

Option	Score	Overall assessment	Take forward?
Option 3: Energy storage specific tariff	3.43	This option is limited in that it only addresses issues for storage. However, it would have limited impacts for other participants, and would be relatively simple to implement and so it does score highly as a quick win option that could deliver improvements without significant challenges, albeit with the caveat that it does not address many wider concerns around the current arrangements.	Yes
Option 4: TNUoS demand credits	3.86	This option would provide strong signals for locating demand near sources of excess generation, helping to support net zero and providing stronger investment signals for storage and other low carbon demand. The option could incentivise demand to locate close to sources of excess generation, helping to improve the business case of net zero enabling technologies such as storage and hydrogen electrolysers. It would also improve cost reflectivity. However, it could be a significant step change from current arrangements and be challenging to implement.	Yes
Option 5: Reform the reference node to remove the need for the EU Adjustment element	3.29	While this would help to improve cost reflectivity, it does not score as highly on the other REMA specific criteria. We note this option is being considered by the TNUoS Task Force, where it will be helpful to consider the implications in more detail.	Yes
Option 2: Single technology agnostic generator TNUoS tariff with scaling factors	3.29	The option would improve cost reflectivity and is well future proofed, and it would offer similar benefits to the technology specific generator TNUoS tariffs option. Complexities around implementation and limited improvements to investability may hold this option back. Overall, our analysis found that the energy storage specific tariff would be a better option for reforming TNUoS generator charges, and these options are not mutually compatible.	No
Option 1: Individual technology specific generator TNUoS tariffs	3.14	This is a relatively low scoring option, recognising the limited extent to which it would support the level of investment needed to meet net zero. Although it would be relatively simple to implement as an evolution of the existing arrangements, it would not help to address volatility concerns, and the extent to which it would be more appropriate for technologies such as wind and solar is limited. Overall, our analysis found that the energy storage specific tariff would be a better option for reforming TNUoS generator charges, and these options are not mutually compatible.	No

4.2 Options for constraint management

Constraints by their nature are locational issues, and as such need some kind of locational signal or market to manage them, which is currently performed by the Balancing Mechanism combined with some ancillary services and bilateral contracts with ESO. Improvements to existing arrangements may require a more granular locational approach to manage than the issues identified with TNUoS.

In this paper we have considered the Offer (generation turn up/demand turn down) side of constraints. This is because we are aware of other work currently being undertaken that covers the Bid (generation turn down/demand turn up) side of constraints via CfD reform.

The seven shortlisted constraint management options are as follows:

4.2.1 Constraint management option 1: Demand turn-up auctions (planning)

Recommended

Overview

- Take the current approach taken for generation capacity adequacy, the Capacity Market (CM), and replicate it for locational demand adequacy
- Goal: provide a locational investment signal to incentivise demand users to locate in areas where there is excess generation that would otherwise need to be curtailed
- **Outcome: Recommended as this option could reduce the levels of renewable curtailment and possibly support the deployment of Net Zero enabling demand**

Option structure

- Local auctions for demand users which could follow a similar format to the existing CM scheme, with auctions procuring demand capacity with participants submitting £/kW bids and clearing prices determined on a pay as cleared basis. As constraints are locational, auctions could be held on a regional basis
- Auction structure could mirror the CM with a combination of long-term and short-term auctions to ensure adequate demand is on the system in the long-term and also to manage any short-term challenges
- Agreements could be provided on a flat capacity basis (i.e. no volumetric or utilisation signal), with participants tested against their consumption during periods of peak constraint (defined as per TNUoS option 4). This could be determined ex post annually based on average consumption during periods with the greatest volume of congestion management including dispatch of demand turn-up, as well as system actions taken in the BM to reduce generation output. This would provide some alignment with the current Triad and CM approaches

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	Incentivising demand to locate in areas of excess renewables would provide an alternative to generation turn down, reducing constraint costs. However, it could provide a perverse incentive for demand to increase if not implemented carefully, and certain areas may see constraints 'flip' if too much demand is incentivised to locate in specific areas.	3
Meeting Net Zero	The extent to which the option meets net zero would depend on the users that would be eligible to participate. If the auctions had emissions limits, were restricted to low carbon assets, or required renewable electricity supply then there could be a slight benefit if the scheme overall helps to support technologies that contribute to decarbonisation such as electrolysers, storage, electric vehicles and heat pumps.	3
Investability	The auctions would provide an additional revenue stream for locating demand in high renewable areas, albeit with additional complexity from participating in the auctions.	3
Cost reflectivity	Consideration would need to be given to the auction design in order to ensure payments to providers are reflective of the benefit they are providing to the system.	4
Practicality	Similar schemes have been demonstrated in the past, such as the ESO's Demand Turn Up service. More recently, the Optional Downward Flexibility Management Service was introduced on very short timescales.	4
Future proofing	The use of auctions would allow changes to locations and capacity requirements to be reflected on an ongoing basis.	3
Acceptability	Previous Demand Turn Up auctions were discontinued due to low participation from industry, with concerns including the long notice period for delivery and small procurement volumes. With improvements, such a scheme could be more appealing to industry, especially with a growing need for constraint management.	4

Wider considerations: It would be important to consider how this option would interact with potential changes to demand TNUoS, such as demand TNUoS credits. There is a question as to whether this market-based approach or TNUoS based approach would provide a better locational signal and to what degree they are mutually exclusive alternatives, or could complement each other.

This option would be actively incentivising demand, which if done incorrectly, could send a perverse incentive to some users. To avoid this issue consideration would need to be given to which users are incentivised and where. For example, eligibility could be restricted to demand that would support net zero, such as electrolysers or electric vehicle charging, or for all demand users. It would also be important to consider how long these agreements should be for.

4.2.2 Constraint management option 2: Expand Constraint Pathfinder (planning)

Recommended

Overview

- The ESO is currently running a constraint management pathfinder, looking for non-build solutions to reduce system constraints, particularly on the B6 boundary. This option would apply the approach and learnings from the constraint pathfinder on a national basis
- One of the aims of the constraint pathfinder was to establish enduring approaches to managing constraints nationally. This option would therefore effectively be taking forward something that is already in progress
- Goal: to support the early development stages of new technologies that would transition to compete in existing markets on a level playing field basis
- **Outcome: Recommended as an in-train process that would provide system benefits**

Option structure

- As explained above, one of the aims of the pathfinder was to establish enduring approaches to managing constraints nationally, and so this option would effectively be taking forward an existing process.

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	While helping to reduce constraint costs, the constraint management pathfinder has focused on smaller assets helping to relieve constraints, rather than solving them, which remains the responsibility of the BM.	3
Meeting Net Zero	This could make a small contribution to meeting net zero if it enables the development of emerging distributed energy resources to offer constraint management services which can go on to compete on a level playing field basis in the BM as technologies mature.	3
Investability	The possibility of gaining a constraint management contract could be seen as an attractive option to investors, providing more certainty over other options such as the BM.	3
Cost reflectivity	The option would reward participants for their actions in alleviating constraints, providing some level of cost reflectivity.	4
Practicality	The option should be highly implementable, given the previous work under the Constraint Management Pathfinder, with the ESO already taking steps to expand its approach.	5
Future proofing	With yearly tenders the approach could evolve in line with the changing constraint landscape.	4
Acceptability	Likely to be highly acceptable given established processes and relatively low risks.	4
Final score		**3.71**

Wider considerations: Due to its nature, the constraint pathfinder was highly locational, designed to address a local system issue. Consideration should therefore be given as to how suitable or possible it would be to expand the approach to a national scale. It will be important to ensure that the pathfinder approach avoids distorting competition in other markets, such as the wholesale market, BM, and ancillary services.

4.2.3 Constraint management option 3: Updated NOA process (planning)

Recommended

Overview

- Reform of NOA to give ESO greater autonomy over network build decisions
- Goal: allow the ESO to make quicker decisions in relation to network reinforcement works
- **Outcome: Recommended provided a suitable risk-weighted approach is used to mitigate the risk of network overbuild**

Option structure

- Reform the NOA process to allow the ESO more autonomy to take forward efficient reinforcement recommendations without requiring case-by-case Ofgem approval. There would also need to be some kind of safeguard or review process alongside this to avoid the risk of network overbuild as these costs will ultimately be borne by customers
- Implementation could be linked to creation of an independent Future System Operator as proposed by DESNZ and Ofgem, with the potential for the independent Future System Operator to be established in 2024
- It would be important to take a risk weighted approach to network development to ensure the risk of overbuild is managed against the potential opportunity cost of constraints from under build

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	While this could expedite efficient actions to resolve constraint costs, it could also increase the risk of greater network investment than strictly necessary.	4
Meeting Net Zero	The option could help to facilitate faster grid connections for renewable assets, and would also increase the utilisation of low carbon energy by reducing the need to turn down generation such as wind.	4
Investability	This could improve investor confidence if barriers to connections are reduced as a result. However, the impact on TNUoS could be detrimental if charges became significantly higher or more volatile.	4
Cost reflectivity	Removing some of the oversight from Ofgem might reduce the extent to which alternative options are taken, leading to costs that are higher than necessary.	3
Practicality	The option should be implementable as it would be expanding existing arrangements. However, determining the extent of power that the ESO would have to move forward with projects may be difficult.	3
Future proofing	Giving the ESO more power to determine the works it takes forward could allow quicker decisions to be made in order to better accommodate changes to the network and new connections/technologies.	4
Acceptability	There may be issues with acceptability due to the ability for additional costs to be passed through TNUoS, but expediting necessary changes may be appealing to some.	2
Final score		**3.43**

Wider considerations: The goal of this option would be to increase the speed in which the ESO is able to make improvements to the network. Whilst the objective is this would allow constraints to be addressed more quickly, there is also a risk that it allows the ESO to incur greater costs that ultimately will be borne by customers. Therefore, the potential benefits of faster grid connections for generators and reduced constraint costs would need to be consider against the potential increased cost for improvement works. To protect against this risk, there may be a case for more rigorous ex-post evaluation of the ESO's network planning decisions to ensure the ESO is held to account.

4.2.4 Constraint management option 4: Improved ESO data provision (planning/ operational)

Recommended

Overview

- The ESO would provide increased system information to the market over longer-term timescales (e.g. week-ahead, year ahead, etc). Unlike other options considered, this option would provide information to market to act on.
- Goal: provide the market with increased visibility of potential system requirements to inform asset siting and operational approach
- **Outcome: Recommended as a low-regrets option that could result in benefits for market participants**

Option structure

- Require the ESO to publish as much information as is possible and reasonably practical on future network constraints. The ESO already does publish information, for example through the NOA process and the Electricity Ten Year Statement, so this option is being considered as an extension of this

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	More information provision could offer greater visibility over likely constraint management actions from the ESO, and therefore influence siting and operational decisions. However, it is unlikely that it would have a significant impact on constraint costs as a standalone option.	3
Meeting Net Zero	More likely to support investment and efficient operation of technologies that complement and enable investment in renewables, such as storage and demand turn-up, rather than directly support the investment and operational decisions of renewables themselves.	3
Investability	It would be more likely to support the business case for investments that have short lead times and relatively short project life, such as electrolysers, batteries and other small scale flexible assets.	3
Cost reflectivity	Not expected to have a significant impact on cost reflectivity.	3
Practicality	The option should be relatively easy to implement, depending on the availability of the information.	4
Future proofing	The option would be able to adapt to future market arrangements, with increased data provision where necessary.	4
Acceptability	This is likely to be very acceptable as increased information will not be detrimental to any parties, although the cost benefit balance would need to be considered.	4
Final score		

Wider considerations: The main initial consideration in relation to this option is whether or not providing market information without making specific or targeted intervention would provide a strong enough signal or incentive to avoid or help manage constraints. This option may be thought of a complementary solution that can be implemented alongside other changes.

4.2.5 Constraint management option 5: Enhanced BM (operational)

Recommended

Overview

- BM participants required to provide an indication of their intent over the coming 24 hours, subsequently overwritten by the current approach of submitting Final Physical Notifications (FPNs) an hour ahead of gate closure
- Goal: provide ESO with advanced notice of likely constraints, allowing actions to be taken earlier
- **Outcome: Recommended as it could provide the ESO with greater early site of potential constraints, which would allow them to manage them in a more economically efficient way**

Option structure

- BM participants required to provide a rolling 24-hour view of their expected output and Bid and Offer prices. This would be in addition to the existing approach of providing Physical Notifications of intended volumes in advance. These would be overwritten with Final Physical Notifications and Bid-Offer price pairs ahead of gate closure in line with the current trading arrangements
- We propose that a mechanism be included to incentivise participants to forecast accurately, but we do not have a view on the exact form this should take. We did also consider penalising participants for inaccurate forecasting but we do not believe this would be as implementable

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	Giving the ESO greater visibility and accuracy over expected constraints and the price of options to manage them could allow it to optimise its management approach, reducing the need for curtailment and maximising the volume of renewables on the system at any given time.	3
Meeting Net Zero	Improving the ESO's view of likely constraints at an earlier timescale could provide more time to consider taking less carbon intensive actions. However, it is not likely to make an impact on the business cases for low carbon technologies as a standalone option.	3
Investability	The option is not expected to have a significant impact on investor confidence.	2
Cost reflectivity	There may be some slight improvements to imbalance cost reflectivity if the additional visibility of likely constraints allows the ESO to take a more measured approach to addressing issues.	4
Practicality	This should be reasonably straight forward to implement as it builds on existing processes.	5
Future proofing	The arrangements would be able to adapt to future arrangements, for example by requiring different information or changing the timescales based on operational requirements.	4
Acceptability	In the REMA consultation, the government suggested that reducing the gate closure window could enable generators to make their final positions more accurate, therefore reducing the need for balancing action. By introducing a requirement to provide notifications on a rolling basis, this option could complement such changes under REMA. Additionally, as it creates more obligations for BM participants it could face some pushback, but compared to other potential reforms this is not likely to be a major issue.	4
Final score		**3.57**

Wider considerations: An initial consideration for this option is which users would be required to provide initial views on what they are planning to do. For example, it could be all BM participants, all generators, all non-flexible generators or a different group.

In addition, there is a question of how firm a requirement this would be, i.e. could a participant face a penalty for deviating from what they said they would do, or should there be incentives for accurate initial forecasts.

4.2.6 Constraint management option 6: Physical Transmission Rights (operational)

Shortlisted

Overview

- Physical Transmission Rights (PTRs) would be allocated specifically in relation to pre-defined constrained boundaries. This would essentially replicate the Capacity Allocation and Congestion Management (CACM) model used for EU interconnector trading
- Goal: restrict power flows over constrained areas of network by removing financially-firm access from generators in constrained locations
- **Outcome: Not recommended as this option would represent a significant change to the current market arrangements that is unlikely to be accepted by the wider market**

Option structure

- There are a large number of changes that would need to be made for this option to be implemented. At a high level, for this option the ESO would be required to determine "significant constraints". The ESO would have flexibility in determining where it sees these areas, subject to a justification process (number of actions taken, expected future issues, etc). Generators on the side of the constraint where generation exceeds demand, within a predefined area, would then be required to participate in PTR auctions to secure the right to flow power over the network on an annual basis
- The revenue recovered through these auctions would be ringfenced by the ESO to fund or part fund reinforcement work to remove the constraint and the associated need for these auctions

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	This would in theory reduce constraint costs to a minimum by reducing access to constrained parts of the network. However, it would do this by redistribution rather than genuine reduction in system cost and may not necessarily incentivise efficient upgrade of the network to avoid issues in the long term.	5
Meeting Net Zero	The option could hinder the deployment of renewable generation in constrained areas. As these are currently areas where conditions are suitable for high renewable output, decarbonisation efforts could be hindered.	2
Investability	The additional costs and complexity of Physical Transmission Rights would likely damage investor confidence due to increased costs in constrained areas.	1
Cost reflectivity	The price of a PTR will reflect the value to generators, but will not reflect the incremental investment cost of network required to alleviate those constraints.	3
Practicality	Likely to be complex to implement, both in terms of the methodology itself as well as the wider interactions with the existing TNUoS regime. There are some parallels with the process used for interconnector trading in Europe which could provide a steer.	2
Future proofing	Once a methodology is established it should be appropriate for future network conditions and new technologies.	4
Acceptability	This is unlikely to be an acceptable option for industry, with the potential for significant costs to be imposed on participants.	1
Final score		**2.57**

Wider considerations: Currently purchasing TEC provides generators with access to the electricity network or compensation through the BM if they cannot have access, which is in effect a Financial Transmission Right. Therefore, if this option were taken forward it will be important to consider both how TNUoS charges would need to evolve to allow it, and how it would work alongside the options for TNUoS reforms being considered. It would also be important to consider an appropriate level of compensation for generators if they had existing financially-firm transmission access rights taken away from them.

As this option would relate to pre-defined constrained boundaries it will be important to consider on what basis these boundaries are set and revised.

More widely, this option would represent a significant revolutionary change to the current approach of connect and manage and financially firm network access.

4.2.7 Constraint management option 7: Incentivise demand BM participation (operational)

Recommended

Overview

- Incentivise and support demand users to participate in the BM to a greater extent
- Goal: increase the pool of BM participants that are able to provide flexibility. This could include incentivising demand users to turn up during periods of high renewable output rather than needing to constrain the renewable output, as well as turning down at times of tight system margin
- **Outcome: Recommended as a low regrets option that could support competition more generally**

Option structure

- Currently BM users are able to participate in the BM, but this is typically more accessible for larger demand users, and typically in relation to demand turn down. Broader participation may be delivered through routes including aggregation services and automated smart systems associated with new forms of low carbon demand, such as EV charging points and heat pumps
- There are various recent work streams that have focused on allowing easier access to the BM both generally and specifically for smaller users. While this has been focused on generation and DSR providers we believe the same processes could be easily adapted to allow small-scale demand users to participate in the BM

Detailed assessment:

Criteria	Assessment	Score
Addressing the problem statement	Would depend on the number of assets that would be able to benefit from increased access. Would unlock the potential for demand side and smaller flexible assets regarding more economically efficient operational dispatch to better meet system needs	3
Meeting Net Zero	Incentivising demand to offtake excess renewable generation could help to support low carbon technologies.	3
Investability	This would support the business case for investing in low carbon generation by making the energy system more flexible and efficient.	3
Cost reflectivity	Improve cost reflectivity of operational dispatch signals for smaller market participants.	4
Practicality	Should be relatively easy to implement as it would build on existing arrangements rather than introducing new ones.	4
Future proofing	Would be able to adapt to new sources of demand and support broader access to the BM from new technologies.	4
Acceptability	Should be acceptable due to limited deviation from current arrangements and limited impacts on existing participants.	4
Final score		**3.57**

Wider considerations: The main consideration for this option is the degree to which it is appropriate to be incentivising demand users to increase consumption at particular times. It would be important to consider how the design of low carbon support schemes can avoid the risk of creating an incentive to consume power for no additional value. For example, low carbon support schemes paid on deemed generation would largely remove negative bid prices, so to be in economic merit, demand would also have to post positive bid prices, so demand would not be paid to turn up consumption. It would also be important to consider how demand participation in the BM interacts with other non-commodity retail levies, such as low carbon support levies, which have the potential to distort demand competition in the BM.

4.2.8 Overall assessment of constraint management options

Based on the detailed options assessment, six constraint management options are recommended for further consideration.

Figure 15: Overall assessment of constrain management options

Option	Score	Overall assessment	Take forward?
Option 2: Expand Constraint Pathfinder	3.71	The Constraint Management Pathfinder has been successful in procuring investment in smaller scale assets to alleviate constraints. However, the ESO has recognised that it only helps to a certain extent, with the BM still used as the main operational dispatch tool for constraint management. This limits the extent to which it can address the rising constraint costs problem statement, unless the ESO can substantially increase the scale of long-term constraint management contracts it is offering. To reduce the risk of causing distortions, or unintended consequences, it will be important to consider any interaction with potential demand turn-up auctions and TNUoS signals with regards to investment incentives, and also consider any interaction with wholesale prices and the BM with regards to operational dispatch incentives. This could be seen as a low risk option, as it is likely to be accepted by industry.	Yes
Option 5: Enhanced BM	3.57	This option would be relatively easy to implement, and would improve the ESO's visibility of likely constraints ahead of time. We believe this option is worth taking forward as providing the ESO with a better view of potential constraints, and giving it longer to address them could reduce balancing costs.	Yes
Option 7: Incentivise demand BM participation	3.57	This option scored highly on being implementable and having limited impacts on existing participants, while encouraging more participation in the BM. It may be limited in the extent to which it would bring down constraint costs, although, as with the above option, this option is considered to be a 'low regrets' option.	Yes
Option 1: Demand turn-up auctions	3.43	While it would be relatively simple to implement, the extent to which it would bring down costs, encourage investment, and support net zero ambitions may be limited. However, as the system and demand become more flexible it may become more attractive and so benefits from further consideration. We think this option could reduce the levels of renewable curtailment and possibly support the deployment of Net Zero enabling demand, although it would be important to consider interactions with potential demand TNUoS credits to avoid double counting investment signals.	Yes
Option 3: Updated NOA process	3.43	This option effectively gives the ESO more ability to take forward the investments it considers necessary, which would help to address constraint costs themselves. However, it would see costs passed on to customers through TNUoS charges instead, and the overall costs to consumers would need to be carefully balanced and monitored. Nevertheless, the option does score highly due to its ability to support the deployment of renewables and the improved ability for the transmission network to quickly adapt to generation landscape changes and new technologies.	Yes
Option 4: Improved ESO data provision	3.43	This is a low-risk option that would improve signals to the market around likely constraints. However, the extent to which this option on its own would address constraint costs is unknown. It also does not by itself provide meaningful investment signals or make a material contribution to meeting Net Zero ambitions. Despite this, this option is considered to be a 'low regrets' option that complements other solutions.	Yes
Option 6: Physical Transmission Rights	2.57	Theoretically this could address all constraint costs, however, it would do this by redistribution rather than genuine reduction in system cost and may not necessarily incentivise efficient upgrade the network to avoid issues in the long term. It would be extremely challenging to implement. It is also expected that it would face significant pushback from industry, and would also potentially hamper net zero ambitions by weaking the business case for renewables in constrained areas, where suitable sites are typically found. Due to these major disadvantages it scores the lowest out of the options.	No

4.3 Recommended option packages

Our analysis suggests that there are a number of options that could improve the existing TNUoS and constraint management arrangements, and that these warrant further exploration. While there is no single option that fully addresses the problem statements as a standalone change, the majority have the potential to deliver an improvement on the existing baseline, and are not mutually exclusive as they address and change different aspects of the market rules. Therefore, by taking forward certain options as packages to be implemented together, more significant improvements could be achieved.

Based on the rankings, the following packages are recommended for further consideration:

TNUoS

All three of the recommended options could be used as standalone changes or in combination with each other:

- Implement demand credits
- Introduce an energy storage specific TNUoS generation tariff
- Reform the reference node to remove the need for the EU Adjustment element

Constraints

Three of the options are identified as low risk changes that can be quickly implemented on their own or alongside other reforms:

- Expand the Constraint Pathfinder (planning)
  - We would note that such activities are already in train, for example with the NOA EC5 Constraint Management Intertrip Service.
- Incentivising demand BM participation (operational)
  - Again, this is something that has already been subject to consideration, with the ESO recently launching the Local Constraint Market for the B6 Boundary
- Improved ESO data provision (planning and operational)

These could sit alongside either one or both of the following options that would represent more substantial changes:

- Enhanced BM (operational)
- Demand turn-up auctions (planning)

We recommend further consideration of the updated NOA process, however, it will be important to ensure the cost of network investment is effectively balanced and monitored compared with the system benefits. These include better delivery of net zero at best system value, taking into account avoided costs associated with congestion management.

5. Roadmap for delivery

Following on from the review and development of the reform options the next step is to consider how these could be delivered to provide access to the identified benefits. In this section we have set out indicative roadmaps for delivery for our shortlisted options. For each option we set out:

- Potential required changes to industry rules (codes, licences, operational practices)
- Interactions with ongoing industry workstreams
- Indicative timelines for implementation

5.1 Required changes to industry rules and operations

Figure 16: Required changes to industry rules and operations

Option	Industry codes	Licences	Operational practices
Energy storage specific tariff	CUSC – Changes required to the tariff calculations shown in section 14.18.7 to include the new tariff	None expected	Limited operational impacts
Implement TNUoS demand credits	CUSC – Would require changes to the requirement for demand tariffs to be floored at £0/kW (14.15.141) – there are a number of references throughout CUSC to the minimum threshold for demand charges of £0	None expected	Moderate operational impacts – the ESO's revenue recovery calculations would need to be updated to include demand credit payments Demand customers could start accounting for credits in their siting and operational decisions
Reform the reference node to remove the need for the EU Adjustment element	CUSC – The model outputs section of CUSC (15.15.24 – 14.15.31) would need to be updated so that references to the proportion of the MW offtake are based on a node's proportion of national generation rather than its proportion of national demand	None expected	Limited operational impacts – the ESO's ICRP DCLF model would need to be updated to reflect a different methodology for determining the reference node
Enhanced BM	BSC – This would need to be updated to reflect the requirement for generators to submit additional Physical Notification data Grid Code – This would require updates to reflect the requirement to submit additional Physical Notification data CUSC – Changes may be needed to the contractual relationship between market participants and the ESO	None expected	Moderate operational impacts – the ESO would need to consider the longer-term view of operational data when managing constraints Participants would need to update their existing processes to account for providing the required data

Option	Industry codes	Licences	Operational practices
Demand turn-up auctions	BSC – Governs some CM processes (rules changes, CMAG etc) that may need to be replicated CUSC – Refers to considering impacts of changes to the CM, which may need to be replicated	None expected	Moderate operational impacts – the ESO would need to run and administer the demand turn-up auctions, forecast requirements and provide guidance documents Participants that wish to benefit from the service would need to actively participate
Expand Constraint Pathfinder	None expected	None expected	Limited operational impacts in general (moderate in areas that require these services) – the ESO would need to run additional processes when there is a need for services If in a relevant area, participants that wish to benefit from the service would need to actively participate
Updated NOA process	None expected	Transmission – May require changes to C27 in the licence	Limited operational impact – the ESO would need to update the way it produces and uses the NOA
Improved ESO data provision	None expected	Transmission – May require changes to the ESO's SLCs	Limited operational impact – the ESO would need to publish the additional data Participants may need to update existing practices to integrate or use the additional data
Incentivising demand BM participation	BSC – may need to be updated to allow this	None expected	Limited operational impact – suppliers and aggregators may need to adjust operational practices to enter smaller-scale demand into the BM

Source: Cornwall Insight

5.2 Interactions with ongoing industry workstreams

The table below sets out the degree to which these reforms may interact or overlap with existing ongoing industry reforms. Given the aim of this paper, REMA has not been included in this as it will apply to all of the proposed solutions. The industry workstreams identified are:

- The TNUoS Taskforce
- CMP413 *Rolling 10-year Wider TNUoS Generation Tariffs*
- CMP405 *TNUoS Locational Demand Signals for Storage*
- CMP375 *Enduring Expansion Constant & Expansion Factor Review* and CMP315 *TNUoS: Review of the Expansion Constant and the Elements of the Transmission System Charged For*
- CMP393 *Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage*
- CMP331 *Option to Replace Generic Annual Load Factors (ALFs) with Site Specific ALFs*
- Future System Operator (FSO) and the Centralised Strategic Network Plan (CSNP)
- EBR Article 16 Consultation
- Demand Flexibility Service (DFS)
- Accelerated Strategic Transmission Investment (ASTI) framework

Below is a summary of the level of interaction we would expect each of the shortlisted options to have with each of the wider industry workstreams identified. For the purpose of this analysis we have used the following terms:

- Significant – The goal and scope of proposed change would significantly overlap with the goal and scope of the workstream
- Partial – The goal and scope of the proposed change may overlap with some areas of the goal and scope of the workstream
- None – The goal and scope of the proposed change is not expected to have any overlap with the goal and scope of the workstream

A more detailed overview of each workstream is provided in the appendix.

We have also considered the potential interactions between all of our recommended options and we believe they could all be implemented together without negatively impacting each other.

Figure 17: Expected interactions between recommended options and ongoing industry workstreams

Option	TNUoS taskforce	CMP413	CMP405	CMP375 and 315	CMP393	CMP331	FSO consultation	EBR consultation	DFS	ASTI
Energy storage specific tariff	Significant	Partial	Significant	Partial	Significant	Significant	None	None	None	None
Implement TNUoS demand credits	Significant	Partial	Significant	Partial	Partial	None	Partial	None	None	Partial
Reform the reference node to remove the need for the EU Adjustment element	Significant	Partial	Partial	Partial	None	None	None	None	None	Partial
Demand turn-up auctions	None	None	Partial	None	None	None	Partial	None	None	None
Expand Constraint Pathfinder	None	None	None	None	None	None	Partial	None	None	Partial
Updated NOA process	None	None	None	None	None	None	Partial	None	None	Significant
Improved ESO data provision	None	None	None	None	None	None	Significant	None	None	None
Enhanced BM	None	None	None	None	None	None	Partial	Significant	Significant	None
Incentivising demand BM participation	None	None	None	None	None	None	None	Partial	Significant	None

Source: Cornwall Insight

5.3 Indicative timelines for implementation

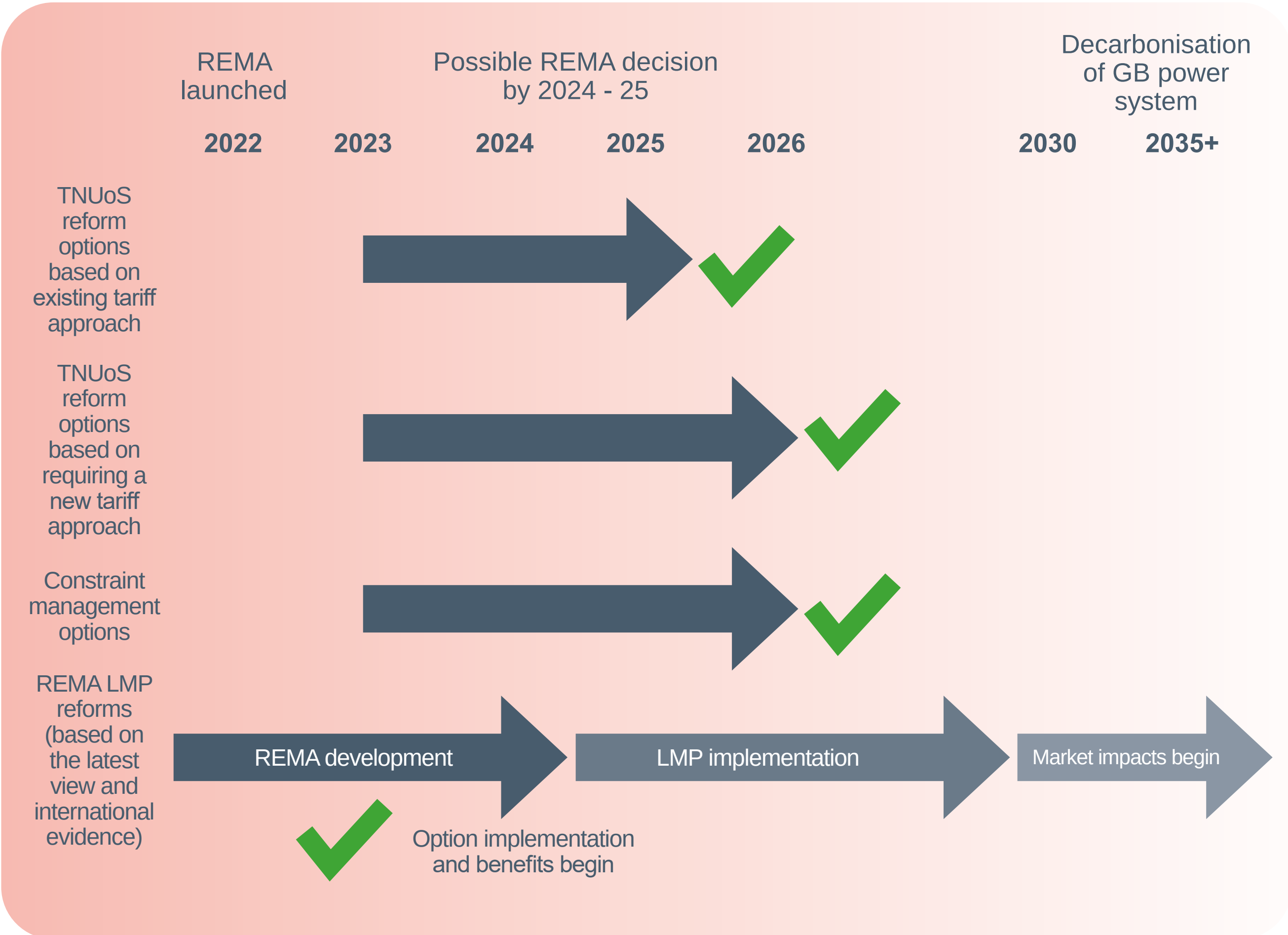
Below we have set out our indicative views on the time we believe it would take to fully implement these options. These timelines are based on our best estimate of the time required to go from raising a modification or change proposal to the change being fully implemented and being in effect.

As with any industry changes these timelines are subject to change and are primarily intended to show the relative speed of implementing the options against each other rather than provide an exact timeline.

- Energy storage specific tariff – 6-12 months for decision + 6-18 months for implementation (potential for delay given interactions with TNUoS Task Force)
- TNUoS demand credits – 18-24 months for decision + 6-18 months for implementation (potential for delay given interactions with TNUoS Task Force)
- Reform the reference node to remove the need for the EU Adjustment element – 18-24 months for decision + 6-18 months for implementation (potential for delay given interactions with TNUoS Task Force)
- Expand the Constraint Management Pathfinder - 6-12 months for decision + 6-12 months for implementation
- Incentivising demand BM participation – 6-12 months for decision + 6-12 months for implementation
- Improved ESO data provision - 6-12 months for decision + 6-12 months for implementation
- Enhanced BM – 12-18 months for decision + 12-18 months for implementation
- Demand turn-up auctions – 18-24 months + 12-18 months for implementation

For comparison, we believe that based on current timelines, a REMA decision may not come before the end of 2024, and some of the more revolutionary options such as LMP would not be able to be implemented until the early to mid 2030s at the earliest.

Figure 18: Indicative comparison of different reform options



6. Next steps

Based on our analysis we recommend that the following options are considered in greater detail for potential implementation:

- Energy storage specific tariff
- TNUoS demand credits
- Reform the reference node to remove the need for the EU Adjustment element
- Expand the Constraint Management Pathfinder
- Incentivising demand BM participation
- Improved ESO data provision
- Enhanced BM
- Demand turn-up auctions

All of these options have the potential to address issues identified as part of the government's REMA consultation, but in our opinion would be more easily implemented and result in less market disruption and uncertainty.

Some of the options could build upon work already undertaken as part of existing processes or code modifications, such as:

- Energy storage specific tariff
  - Similar to proposals being considered as part of CMP393 *Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage* and CMP405 *TNUoS Locational Demand Signals for Storage*
- TNUoS demand credits
  - Could draw upon work undertaken for CMP405 *TNUoS Locational Demand Signals for Storage*
- Expand the Constraint Management Pathfinder
  - Transferring the pathfinder processes into business as usual practices was always part of their development

Depending on the exact form these options take, it may be possible to combine them into these existing workstreams, which may speed up their implementation. However, it may not be possible to do this if these workstreams are already well developed at the time, in which case a new modification process may be needed for the two TNUoS options.

For the remaining options we believe new industry workstreams would be needed for them to be implemented. It may be possible for some of these to be submitted in their current form as code modifications, but they may also benefit from additional analysis before proposals are raised. This is because for some of the options there are either multiple potential approaches to implementation, or unanswered questions raised as part of this initial analysis.

We do not consider that the timelines for implementation, or any potential interactions between options are a material challenge. As the previous section showed, the timelines for implementation vary between options depending on the scale of the change required. We therefore recommend that in order to see the benefit of these options they are progressed concurrently.

7. Appendix

7.1 Additional longlisted options

A number of options were part of the longlist. Many of these may have merit and could warrant further development, however they did not pass the shortlisting exercise with regards to the specific problem statement. These additional options are detailed below.

TNUoS option: Align demand and generation TNUoS zone

Overview

- Currently there are 27 generation and 14 demand zones for TNUoS charging and their boundaries do not align. Under this option, these zones would be aligned, which could be done in three ways:
  - Align generation zones with the existing demand zones as per modification proposal CMP324 and CMP325
  - Align demand zones with the existing generation zones
  - Create new zones that align for both
- The goal of this option would be to better align the treatment of generation and demand in relation to TNUoS charging.

Option structure

- We believe that of the options presented above, aligning generation zones with the existing demand zones is the most suitable. This is because changing demand zones would have impacts on domestic and other small users of the network, potentially changing the charges they face and creating more of a ‘postcode lottery’. We do not believe this is proportional or fair and therefore are considering only amending the generation zones to align with the current demand zones.

TNUoS option: Align TNUoS charging approach for demand and generation

Overview

- Under the current charging approach, generators are charged TNUoS on a fixed £/kW basis related to their Transmission Entry Capacity (TEC). This cost is fixed for each year regardless of the amount of power the site exports. Demand, however, is charged based on a combination of a price signal based on their consumption, or assumed consumption, during the three Triad periods and residual revenue collection as a flat £/site charge (banded by consumption). There are again three high level options for implementing this option:
    - Align generation charging with the existing demand approach
    - Align demand charging with the existing generation approach
    - Create a new charging approach that aligns for both
- The goal of this option would be to better align the treatment of generation and demand in relation to TNUoS charging.

Option structure

- We believe that of the options presented above, better alignment of demand with the existing approach for generation is the most suitable. There are likely to be lessons from the changes to generation charges following Project TransmiT that could improve the cost reflectivity of demand charges, such as using a different demand charging base for the Year Round element of tariffs, compared with the Peak Security element and how to best apply signals from negative tariffs. As mentioned for the previous option, changing demand treatment would have impacts on domestic and other small users of the network, potentially changing the charges they face, which should be taken into account in any proposals.
- We note that modification proposal CMP271 was raised 7 years ago to better align demand charges with the existing generation approach. It may be helpful to revisit this modification, which is still live, but was put on hold awaiting the outcome of the Access SCR and subsequent TNUoS wider review.

TNUoS option: Fix TNUoS charges for a longer period of time

Overview

One of the key concerns with the current approach to setting TNUoS charges is volatility and year-to-year change with limited foresight of published charges. This option would address this by giving long term visibility of TNUoS charges. This could be five years (to align with price control period durations), 10 years, or 15 years (to align with CfD and CM agreements), or longer.

Option structure

- We propose that each user would have a tariff forecast and set for a 10-year period from the point they receive a grid connection offer. Up until that point the current approach of publishing 5-year forecasts and draft tariffs before final tariffs would continue to apply to ensure that the tariff they face is as cost reflective as possible of the network when they connect.
- The forecast would be updated annually for each user on a rolling basis, meaning generators would always have a 10 year view of costs, In year 0 users would have a 'locked in' tariff for years 1-10, then in year 1 they would keep the same tariffs for years 2-10, but will also have a 'locked in' tariff for year 11.

The option would effectively provide long-term certainty over the level of most of the underlying TNUoS tariff elements, namely the Peak, Year Round Shared and Year Round Not Shared elements. However, we do not consider the EU Adjustment element should be fixed as this is a cost recovery mechanism and therefore we believe that fixing it would not be appropriate. The overall tariff would therefore vary based on generator ALFs, and the level of the EU Adjustment. We believe this is necessary to stop users locking in a charge or credit based on an ALF that they then routinely exceed or fail to meet.

Constraint management option: Constraint compliant CM and CfD auctions (planning)

Overview

- The Contracts for Difference (CfD) and Capacity Market (CM) schemes are both national and do not consider locational factors when awarding agreements. This means that a site connecting in a constrained part of the network is able to compete on the exact same basis as a site in an unconstrained area.
- The goal of this option would be to incentivise capacity to locate in non-constrained areas of the network.

Option structure

- Under this option both of these schemes would be reformed to consider locational impacts when awarding agreements. This would be done by updating the auction algorithm to also meet locational capacity targets or limits within overall targets/limits. This is similar to the approach used by the Irish Capacity Remuneration Mechanism (CRM).

Constraint management option: Transmission system availability incentives (planning)

Overview

Under this approach the ESO would be financially incentivised to ensure transmission system availability is maximised and delivered. The goal of this option would be to incentivise the ESO to maintain and operate the transmission system in a way that reduces the amount of time customers are constrained from using it.

Option structure

Availability incentives are an established part of the RIIO process for network companies. This option would effectively build on these for the ESO and TOs to reflect the aim of reduced curtailment of renewable generation.

Constraint management option: Advanced Gate Closure (operational)

Overview

- This option would extend the time period the ESO has to dispatch participants in the BM. Currently Gate Closure is one hour before the start of the settlement period, but under this option this window would be extended. The ESO can already take some pre-gate closure actions, but currently this is limited.
- The goal of this option would be to extend the time the ESO has to find a cost-efficient way to manage any constraints. It would also provide the ESO with a longer-term view of what participants plan to do.

Option structure

- For this option Gate Closure could be extended from 1 hour ahead of delivery until 24 hours ahead of delivery. This would apply to all renewable and baseload generator BM participants. In practice this would be a more ‘binding’ version of the Enhanced BM option. There would also need to be a non-delivery penalty if participants deviate from their FPN. We note that currently deviating from an FPN is a licence breach, but continuing this approach may be overly punitive and alternative penalties regime may be required.

Constraint management option: Project TERRE (operational)

Overview

- The Trans European Replacement Reserves Exchange (TERRE) project is an EU scheme designed to support and improve the balancing of interconnected energy markets by using a standard product for balancing energy. Prior to the UK leaving the EU, it was expected that the GB energy market would take part in TERRE, which would have provided an additional mechanism for managing network constraints across interconnectors. However, there are no longer any plans to become a formal member of TERRE.
- The goal of this option would be to deepen the potential market of balancing service providers.

Option structure

- This option would see the GB market become part of TERRE, and therefore have potential access to a wider pool of balancing services. In practical terms we would expect GB participants to engage with TERRE via the BM. This would see the ESO be provided a net required position via TERRE, which it then achieves by instructing participants via the BM.

Constraint management option: Split BM (operational)

Overview

- This option would see BM participants submit separate energy and system action Bids and Offers. Currently BM participants must adhere to the Transmission Constraint Licence Condition (TCLC), which prevents licenced generators from excessively benefitting from network constraints. This means that if a generator is called on to address a system constraint (i.e. for a system action), the price of its Bid must be objectively justified with a reference to specific costs and risks priced in the bid.
- As it is not always possible to know if an action is being taken for system or energy reasons participants typically have to ensure that the Bid or Offer they submit is cost reflective to avoid being in breach of the TCLC.

Option structure

- This option would see participants submit separate Bids and Offers for energy actions and system actions. The goal of this option would be to ensure participants are able to maintain compliance with the TCLC, whilst also allowing them to maximise revenue when being taken for energy actions.

7.2 TNUoS options shortlisting process

In order to narrow down the initial longlist of options for TNUoS reform into a shortlist for more detailed assessment we scored each of them against the three gating criteria set out above. This assessment is set out in the table below.

Figure 19: TNUoS options shortlisting

Option	Ofgem criteria	Feasability of implementation	Addresses the problem statement	Overall score	Take forward?
New set of generator TNUoS tariffs	*This option was considered alongside the individual technology specific generator TNUoS tariffs options for the purposes of scoring*				
Individual technology specific generator TNUoS tariffs	3	3	2	8	Yes
A single technology agnostic generator TNUoS tariff with scaling factors	2	2	2	6	Yes
Energy storage specific tariff	3	3	1	7	Yes
Implement TNUoS demand credits	2	3	2	7	Yes
Proportional allocation of the EU Adjustment element	1	2	1	4	No
Reform the reference node to remove the need for the EU Adjustment element	3	2	1	6	Yes
Align demand and generation TNUoS zones	1	2	1	4	No
Align TNUoS charging approach for demand and generation	2	1	2	5	No
Fix TNUoS charges for a longer period of time	2	2	0	0	No*

Source: Cornwall Insight

**while this fails to solve the problem statement due to its design, we still think there is value in it and it could be taken forward separately to this piece of work*

Based on this assessment the following options were taken forward for detailed assessment:

- New generator TNUoS tariffs
- Technology specific generator TNUoS tariffs
- A single technology agnostic generator TNUoS tariff
- Energy storage specific tariff
- Implement demand credits
- Remove the EU Adjustment element by design

7.3 Constraint management options shortlisting process

In order to narrow down the initial longlist of options for constraint management into a shortlist for more detailed assessment we scored each of them against the three gating criteria set out above. This assessment is set out in the table below.

Figure 20: Constraint management options shortlisting

Option	Ofgem criteria	Feasibility of implementation	Addresses the problem statement	Overall score	Take forward?
Enhanced BM	2	3	1	6	Yes
Advanced Gate Closure	2	1	2	5	No
Physical Transmission Rights	2	1	3	6	Yes
Demand turn-up Auctions	1	3	2	6	Yes
Expand Constraint Pathfinder	3	3	1	7	Yes
Project TERRE	2	1	1	4	No
Split BM	2	2	0	0	No
Constraint compliant CM and CfD auctions	2	1	2	5	No
Updated NOA process	2	2	3	7	Yes
Improved ESO data provision	3	3	1	7	Yes
Transmission system availability incentives	2	2	1	5	No
Incentivise demand BM participation	2	3	1	6	Yes

Source: Cornwall Insight

Based on this assessment the following options were taken forward for detailed assessment:

- Enhanced BM
- Physical Transmission Rights
- Demand turn-up auctions
- Expand Constraint Pathfinder
- Updated NOA process
- Improved ESO data provision
- Incentivising demand BM participation

7.4 Relevant ongoing industry reforms and workstreams

7.4.1 TNUoS Taskforce

In February 2022, Ofgem issued its next steps on a wide-ranging review of TNUoS charges, deciding that the review would be an industry-run Task Force led by the ESO, similar to the model used for the BSUoS Task Forces.

Ofgem's view is that TNUoS is currently unable to effectively deliver a stable long-term investment signal to generation or large demand users due to its unpredictability. The Task Force's scope is therefore to consider the root causes of unpredictability in TNUoS charges and how they might be addressed. Areas in scope of the Task Force include but are not limited to:

- The input data for the current model used to calculate the locational elements of TNUoS to consider how they impact on the predictability of tariffs as a long-run investment signal
- The wider TNUoS charge components and how they are calculated (excluding the adjustment tariff), along with the approach to zoning
- The extent to which the methodology should align with the real worl operation of the system
- Potential new inputs into the methodology
- The elements of TNUoS charges that should be paid by distributed generation
- Changes that will simplify the methodology and make it easier to engage with for new market participants
- The treatment of island connections, and some offshore developments

Ofgem will undertake a parallel programme to look at the longer-term purpose and structure of transmission charges, considering the trade-offs between market signals, network planning, and network charging signals in fostering a flexible Net Zero energy system.

In November 2022 Ofgem announced that it was pausing the TNUoS Task Force to prioritise winter activities. It was confirmed in March 2023 that the Task Force would be reinstated in April. To date there has been limited activity on developing options under the Task Force, but we would expect that some of the potential reforms in this report will be subject to discussion.

7.4.2 CMP413 *Rolling 10-year Wider TNUoS Generation Tariffs*

CMP413 Rolling 10-year Wider TNUoS Generation Tariffs seeks to obligate the ESO to publish generation tariffs for a rolling 10-year period, and provide clarity to network users to support commercial decisions to deliver low carbon infrastructure (across generation and networks) at least cost for consumers.

TNUoS charges are designed to provide long-term siting signals to support the economic development of the transmission network. Due to the large scale of transmission investment needed in the coming decades, and the generally long development timeframes for low carbon generation, the proposer (EDF) believes that the current TNUoS methodology will fail to meet this objective.

The current TNUoS charging methodology sets transmission charges for the coming year based on the existing network and expected generation and demand. In addition, the ESO does not publish a forecast of TNUoS locational signals that reflect the significant changes expected in the coming decade. In particular, the proposer does not believe that current TNUoS charges provide a useful siting signal for generators, which leads to uneconomic transmission system development. Therefore, the cost of transmission will not be correctly assessed by low carbon developers if they are to participate in the Contracts for Difference auctions.

The proposer's solution to this issue is:

- ESO to publish a wider generation tariff for each generation zone for a rolling 10-year period
  - This process could work alongside the ESO's annual strategic network plan assessment
- For each subsequent 10-year tariff publication, if tariffs in any generation zone breaches a pre-defined range (proposed to be set as non-inflated +/-£/kW value per generation zone and set out below), for the years in the initial forecast, charges are capped/floored at a predefined range for the zone
  - Any adjustment mechanism would only come into effect if any subsequent tariffs published by the ESO differs from the initial forecast by more than the pre-defined range
  - The net difference in the TNUoS tariff, if it breaches the pre-defined range, across all generation zones would be recovered through demand TNUoS charges
  - The cap and collar range would increase over the 10-year period, recognising the high degree of certainty in year 1 and the greater uncertainty in year 10

This proposal is currently in the workgroup stage.

7.4.3 CMP405 *TNUoS Locational Demand Signals for Storage*

Under the current TNUoS charging methodology, locational demand signals are floored at £0 to avoid sending an operational signal to users to increase their import over peak periods. However, the DCLF model ('the Transport model') shows that in areas dominated by intermittent generation there are significant benefits from demand users importing during periods of peak wind output. CMP405 TNUoS Locational Demand Signals for Storage seeks to separate out the demand Year Round locational signals from Peak Security locational signals and charge (reward) storage assets that import during times other than Triads, i.e. when wind generation is fully operating.

In the modification proposal it was noted that incentivising storage to locate near to intermittent generation (i.e. on the same side of the constraint) could improve the utilisation of network assets, reduce the need for permanent Transmission Investment and reduce constraint costs. The proposer also noted that by changing how the Year Round Demand tariff is charged (away from Triad charging) should better align TNUoS tariffs with actual investment.

7.4.4 CMP375 *Enduring Expansion Constant and Expansion Factor Review*

CMP375 Enduring Expansion Constant and Expansion Factor Review aims to amend the calculation of the Expansion Constant (EC) and Expansion Factors (EF) used in calculating TNUoS charges to better reflect the growth of and investment in the National Electricity Transmission System (NETS). The proposer requested that, at a minimum, the scope of works used in the calculation of the EC should be considered and the rationale for the inclusion/exclusion of all works should be clearly explained. They added that the EF methodologies should align with these principles.

The modification followed the approval of CMP353 Stabilising the Expansion Constant and non-specific Onshore Expansion Factors from 1st April 2021. The EC should be reset at the start of each transmission price control and it was most recently reset in 2016. It should have been recalculated in April 2021, however, forecasts released in late 2020 showed it would increase by 83%. This would have increased generator TNUoS by the same proportion. CMP353 was therefore implemented to hold the EC at its current level while more work was done to understand the big increase and ensure it was cost reflective.

This modification is being progressed in combination with CMP315 (discussed below) due to the significant overlap of their focuses.

7.4.5 CMP315 TNUoS: Review of the Expansion Constant and the Elements of the Transmission System Charged For

As noted above, this modification was rolled into and progressed alongside CMP375. CMP315 TNUoS: Review of the Expansion Constant and the Elements of the Transmission System Charged For was raised to review how the Expansion Constant is determined so that it better reflects the costs involved. The goal of the change would be to improve the cost reflectivity of the TNUoS locational charge so that it better reflects the actual costs imposed on the transmission system by the siting decisions taken by generation and/or demand.

7.4.6 CMP393 *Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage*

Annual Load Factors (ALFs) are used as part of the calculation of generator TNUoS charges. Currently these are based on the power exported by a site, meaning that for storage assets the imported power is not considered in determining the overall charge they face. CMP393 Using Imports and Exports to Calculate Annual Load Factor for Storage would alter the definition of ALFs in respect to storage to also account for imports.

The proposer argued that the current TNUoS methodology does not accurately reflect how storage assets interact with the National Electricity Transmission System. They suggest that defining a ‘Storage ALF’ based on a site’s net demand (gross demand volume – gross generation volume).

7.4.7 CMP331 *Option to Replace Generic Annual Load Factors (ALFs) with Site Specific ALFs*

Until an asset has enough operational data available it’s TNUoS charges are based on generic ALFs, which are based on its generating technology. The proposer noted that applying generic ALFs results in less cost-reflective TNUoS charges as it may be materially different from the actual ALF the site is operating at. The result is that new generators may incur a wider TNUoS charge over the first three years of operation that does not reflect the actual usage of the site. CMP331 Option to Replace Generic Annual Load Factors (ALFs) with Site Specific ALFs aims to address this issue by allowing users to provide their own ALFs for the first three years of operation based on expected output. These values would then need approval from the ESO.

7.4.8 Future System Operator (FSO) supply and demand modelling consultation/CSNP

In November 2022 Ofgem announced its decision that the new Future System Operator (FSO) should deliver a new electricity transmission network planning output called a Centralised Strategic Network Plan (CSNP). Subsequently, in May 2023, the regulator launched a consultation on its proposals for the first CSNP regulatory framework development, which is how it expects the FSO to model future supply and demand. This will inform the need for future network investment in the CSNP. The consultation set out a number of areas where Ofgem was proposing to make changes to the Future Energy Scenarios (FES) to improve inputs to the first CSNP.

This consultation closed on 24 June 2023 and responses are currently still awaited.

7.4.9 EBR Article 16 Consultation

On 14 June 2023, the ESO published a consultation on proposed amendments to the terms and conditions related to balancing. The proposal includes the launch of a new combined auction platform, the Enduring Auction Capability (EAC), for the procurement of frequency response services: Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR). the ESO proposes that the platform will extend to the procurement of new reserve services: Slow Reserve (SR) and Quick Reserve (QR).

The proposed changes will create a new set of procurement rules, and simultaneously make consequential changes to existing procurement rules and service terms currently in use for procurement for those frequency response services. The consultation also proposes to make changes to the performance monitoring to enable service stacking. This would change the way the current market works for frequency response to allow for a unit's capacity to be split across different frequency response services at the same time. In addition, the consultation sets out a new market design named Co-optimisation, which will allow for units with capability to provide more than one service and let the auction clearing algorithm allocate the unit with the service that will clear the market most efficiently.

Alongside this consultation, the ESO published the updated EAC mapping document for the frequency and response service and a destination table showing where provisions currently found in the existing frequency response procurement.

7.4.10 Demand Flexibility Service

The ESO published a consultation on the future of Demand Flexibility Service (DFS). The consultation sets out the terms and conditions of the revised DFS for Winter 2023, in accordance with the requirements of EBR Article 19. The consultation is also seeking views on the ESO's proposed changes to the terms and conditions.

The consultation is seeking views on several new definitions and changes including the removal of the in-day adjustment within the operational baseline calculations for domestic DFS units. The consultation is also seeking views on what the impact could be of this removal, as well as the plausibility of an alternative in-day adjustment period.

The ESO also proposes to enable the sub-metering as part of DFS rather than just using the boundary supply point meters. To ensure that there is no displacement of energy volumes among sub meters behind a single boundary meter, the ESO proposes that registered service providers must all be included in that providers unit meter point schedule. The consultation is seeking views on how well this proposal mitigates the risk of double counting.

The ESO also proposes to introduce a concept of opt-in, which will cover unit meter points that are not participating for the DFS event unless customers indicate to the registered service provider that it wishes to opt-in. Conversely, the consultation proposes an opt-out concept that will allow for consumers to inform registered service providers that it wishes to opt-out. The consultation is seeking views on these introductions and any risks that could be foreseen.

7.4.11 Accelerated Strategic Transmission Investment (ASTI) framework

As part of the British Energy Security Strategy the government set out its ambition to connect up to 50GW of offshore generation by 2030. In order to achieve this a significant amount of reinforcement will be needed on the electricity transmission system, and change will be needed to the current regulatory framework in order to accelerate delivery of large projects.

In August 2022 Ofgem consulted on how it could support the accelerated delivery of the strategic electricity transmission network upgrades that will be required to meet the government's 2030 renewable electricity targets. Following this, in December 2022, the regulator set out its decision to introduce a new Accelerated Strategic Transmission Investment (ASTI) framework. As part of the announcement Ofgem set out the initial list of ASTI projects; its decision on exempting strategic projects from competition; the new process for assessing and funding ASTI projects; and the range of measures it was introducing to protect consumers against additional risks that changing the process brings.

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