Connection and Use of System Code (CUSC) CMP344: Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology

Decision:	The Authority[1] has decided to reject[2] this modification
Target audience:	National Energy System Operator (NESO), Parties to the CUSC, the CUSC Panel and other interested parties
Date of publication:	01 May 2026

Background

The electricity network

The National Electricity Transmission System (the 'NETS') is the high-voltage electricity network in Great Britain (GB) operated by the National Energy System Operator ('NESO'). The NETS is comprised of onshore and offshore assets owned by Transmission Owners (TOs) or Offshore Transmission Owners (OFTOs), as applicable.

[1] References to the "Authority", "Ofgem", "we" and "our" are used interchangeably in this document. The Authority refers to GEMA, the Gas and Electricity Markets Authority. The Office of Gas and Electricity Markets (Ofgem) supports GEMA in its day-to-day work. This decision is made by or on behalf of GEMA.
[2] This document is notice of the reasons for this decision as required by section 49A of the Electricity Act 1989.

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Whilst the entire network is connected, the offshore network is not currently interconnected in the same way as the onshore network (i.e. by providing multiple paths by which electricity could flow between any two points). Instead, the current offshore network is made up of a number of radial (or point-to-point) transmission cables which typically link a single offshore generator to the onshore transmission system.

To date, all offshore generation has been constructed under the 'generator build' model where a generator designs and installs the offshore generation assets as well as the offshore transmission assets required to link the generation to the onshore network. Following construction, a competitive tender[3] process is run by the Authority and ownership of the offshore transmission assets is transferred to the successful bidder, which is granted an OFTO licence.[4] This is because of unbundling requirements[5], whereby generators are not permitted to own transmission assets. To date we have granted twenty-eight OFTO licences. The generator continues to own, operate and maintain the generation assets.

This contrasts with the onshore network, where generators are responsible for building their generation assets but are not permitted to build, upgrade or otherwise conduct works on transmission assets. Instead, onshore transmission assets are installed by three onshore TOs that own, and are responsible for maintenance of, parts of the transmission system in defined geographical areas in GB.[6]

TO and OFTO revenue recovery

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[3] By virtue of section 6C of the Electricity Act 1989.
[4] Offshore Transmission: Generic Licence and Guidance for TR9 | Ofgem
[5] Unbundling means separating the ownership and operation of a transmission system from other activities, including electricity generation. See sections 10A to 10O of the Electricity Act 1989.
[6] National Grid Electricity Transmission ("NGET") in England and Wales, Scottish Power Transmission (SPT) in the south of Scotland, and Scottish Hydro-Electric Transmission Plc ("SHETP") in the north of Scotland.

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Ofgem sets the allowed revenue of TOs and OFTOs via price controls. For onshore TOs, this is calculated periodically using the RIIO model,[7] with the RIIO-T2 price control revenue values set for years 2021 to 2026, when it will be renewed under RIIO-T3. For each OFTO, the total allowed revenue is set following the tender process immediately prior to the point of the transfer (from the offshore generator to the OFTO) of the transmission assets. This total allowed revenue is referred to as the OFTO's Tender Revenue Stream (TRS), and the revenue is fixed for up to 25 years. The TRS is based on each successful OFTO tenderer's required return on investment, the cost of financing its investment in acquiring the assets and the ongoing cost of financing, operating and managing the assets. It is fixed under the terms of each OFTO licence, with annual values adjusted in line with certain factors, including inflation and asset performance against an annual availability target. As explained in more detail below, the OFTO licence framework also includes mechanisms that allow future adjustments to the TRS for certain events.

TOs' and OFTOs' allowed revenue is recovered by the NESO through levying Transmission Network Use of System ('TNUoS') charges which are applicable to transmission connected generators, distribution connected generators larger than 100MW, and demand users. TNUoS charges recover the cost of provision, owning and maintenance of the transmission infrastructure assets, including a rate of return for the relevant TO or OFTO, as prescribed in its price control. Each TO and OFTO provides NESO with a value to be recovered, serving as an annual 'target revenue' (TO values being subject to the revenue set by the Authority at the start of the price control and OFTO values being based on their TRS). NESO pays each TO and OFTO that value and will set TNUoS tariffs aiming to recover the required value from the relevant users each year.

[7] RIIO stands for 'Revenue = Incentives + Innovation + Outputs'. Network price controls 2021-2026 (RIIO-T2) and 2026-2031 (RIIO-T3) | Ofgem

Offshore generators pay local TNUoS charges ('Offshore Local Charges') which are specific charges a generator pays for the use of the relevant OFTO's assets (i.e. the offshore transmission cable that connects the offshore generation station to the onshore part of the transmission network) and pay wider TNUoS charges in respect of the shared infrastructure they connect into onshore. Offshore Local Charges are adjusted at the outset of each onshore price control for the duration of the OFTO's appointment and are designed to recover the OFTO's revenue (the majority or all of it) for the total capital costs of the project (i.e. the asset transfer value the OFTO pays to the generator to purchase the assets). The Offshore Local Charges calculation also considers the capacity rating of each relevant asset, the generator's Transmission Entry Capacity (TEC) and the Security Factor of the circuit, reflecting a level of network redundancy. These charges are levied on a £/kW basis.

The Offshore Local Charge is calculated by reference to the capacity rating of the offshore transmission assets, therefore, if the generator's capacity matches the capacity rating of the OFTO asset, the total TRS will be recovered from the generator (e.g., an Offshore Local Tariff for a 200MW asset will recover the full value of the target revenue if the generator's capacity is 200MW). However, in many instances, the OFTO assets are of a greater capacity than is required by the generator (e.g., a 200MW OFTO asset built for a 180MW generator) in which case the generator only pays a proportion of the costs based on its own capacity, with the rest of the cost falling to demand consumers. This is because the OFTO is guaranteed to receive its agreed TRS through TNUoS charges and if it is not paid by the relevant generator, it must come from other network users (e.g., the 180MW generator pays 90% of the cost of that 200MW OFTO asset, the remaining 10% is paid by demand consumers).

This is not the case for onshore generators. An onshore generator does not build transmission assets, rather they are built by the TO, so there is no transfer of asset ownership as exists under the offshore regime. Generator TNUoS charges for the assets taking the onshore generator to the meshed onshore transmission system are also 'local' charges, ('Onshore Local Charges') but are calculated in a different way to those applicable to offshore and are not fixed for any period greater than 12 months. Onshore Local Charges are calculated based on how the flows of the transmission system are modelled to rely on or otherwise affect a particular asset and are not set by reference to the actual costs of the cable or the amount of money to be recovered for a particular TO. Instead, each transmission asset is assigned a 'generic value' at the point of price control, and the Onshore Local Charge is designed to reflect the incremental cost conferred to the transmission system by a generator through its use of those assets. Over time it is entirely possible that an asset once deployed for a single generator, attracting Onshore Local Charges, becomes part of the meshed infrastructure of the transmission system and the costs of that asset cease to be borne solely by that generator but are instead paid for by all users in the vicinity via the wider TNUoS charge.

Adjustments to allowed revenue: OFTOs

As noted above, the OFTO licence allows for revenue adjustments ('Pass-through Items') to be made to an OFTO's TRS to reflect costs incurred for certain events, which in turn trigger an adjustment to the Offshore Local Charges payable by the generator utilising the relevant transmission assets. Pass-through Items are provided for in the Amended Standard Condition (ASC) E12-J3s of the OFTO licence.[8] Specifically, paragraphs 14 to 24 of ASC E12-J3 concern the process for pass-through of costs or savings relating to an Income Adjusting Event ('IAE'), subject to approval by Ofgem. An IAE is specified as arising in certain defined circumstances, where an event has changed the costs incurred (or saved) by the OFTO equal to or in excess of specified threshold amounts. An example of a previous IAE is the costs

[8] Offshore Transmission: Generic Licence and Guidance for TR9 | Ofgem

incurred in addressing a cable failure caused by an uninsurable latent defect. The IAE provisions in the OFTO licence are symmetrical, in that the OFTO can recover costs incurred or repay costs saved by an IAE. For ease, this decision letter refers to costs incurred.

Where an OFTO considers an IAE has occurred, it can notify Ofgem and seek the Authority's approval to recover the associated costs within the TRS (via TNUoS charges). If the Authority determines that there has been an IAE, it will set the level of TRS adjustment to reflect the awarded sum.

The OFTO will then request the awarded sum from NESO in the following charging year (for example, if an IAE were to be approved during the 2022/23 charging year (within the onshore price control period) it will be added to the annualised TRS value for recovery during the 2023/24 charging year). Since there is currently no mechanism to change Offshore Local Charges within an onshore price control period, this awarded sum cannot ordinarily be recovered from the generator utilising the offshore transmission assets through TNUoS charges at the time when the OFTO requires payment. As such, NESO will pay the OFTO the awarded sum and will start to recover that additional cost through demand consumer TNUoS charges, specifically using a charge known as the 'Transmission Demand Residual' (TDR). At the beginning of the next price control, when the relevant generator's charges are reset, NESO will increase the relevant Offshore Local Charges paid by the generator (evenly distributed across each of the charging years in that price control period). A reduction is also then incorporated into the TDR paid by consumers in that year, effectively ensuring that consumers are reimbursed for covering the initial cost of the offshore generator's share of the awarded sum.

The current IAE framework contains a mechanism for successful IAE claims where the OFTO asset is not covered by an insurance policy and which, operating similar to an insurance deductible, means that the generator does not always bear the full costs of an IAE claim. In addition, consumers also contribute a share of the total awarded IAE sum where the offshore asset(s) are oversized in comparison to the generator's capacity requirements, i.e. there is spare capacity on the asset(s) (as explained above).

National Grid Electricity System Operator Limited (NGESO), as the Electricity System Operator prior to NESO[9], issued guidance[10] which confirmed the above approach in a letter of 27 July 2017. This process is not codified (i.e. currently included within the terms of the CUSC itself), but the guidance details the operational practice that NESO currently follow.

The general purpose of the IAE condition set out in the OFTO licence (alongside corresponding provisions in the offshore generating licence) is to protect the OFTO's revenue from identified unexpected costs arising from specific low probability but high impact events, by ensuring these sums are recovered through the charging regime.[11]

We assess each such IAE request on its merits and set of specific circumstances and may allow some, none, or all the additional costs to be recovered. However, it is expected that all options in terms of commercial recourse (for example warranties and insurances) are exhausted prior to an IAE claim being requested.

Adjustments to allowed revenue: onshore TOs

[9] On 1 October 2024, NGESO became NESO, a publicly owned entity.
[10] NESO: Reflecting variations in Offshore Transmission Owner (OFTO) revenue in Offshore Local TNUoS Tariffs
[11] Policy – Income Adjusting Events in Offshore Transmission Owner Licences - iae_response_-_final_0.pdf (ofgem.gov.uk)

There is no IAE mechanism in the onshore TO licence. If the onshore TO is required to carry out works (in respect of the onshore meshed transmission network) which were not foreseen at the time its price control was agreed, it is required to either;

- absorb that cost in its overall expenditure over the price control period; or
- approach the Authority to request that its price control be changed within period to allow collection of any additional sums, for example through a Cost and Output Adjusting Event (‘COAE’).

In respect of an onshore local circuit failure, the cost of the TO fixing or replacing an asset is recovered through local circuit charges via an update to the circuit Specific Expansion Factor (SEF) at the start of the next price control period.

We assess each such request on its merits and set of specific circumstances and may allow some, none, or all the additional costs to be recovered.

The modification proposal

RWE (the ‘Proposer’) raised CMP344 (the ‘Proposal’) on 21 May 2020.

CMP344 seeks to change the way in which costs associated with offshore IAEs are recovered; instead of the costs being borne by the generator connected to the OFTO’s transmission assets through an uplift in Offshore Local Charges (as they would be under the status quo), CMP344 would remove the generator’s liability and instead see the costs fully recovered from demand consumers via the TDR TNUoS charge. The modification proposal would apply to generators’ liability in respect of IAEs affecting both existing OFTOs and future OFTOs. In practice, this would mean that the reduction that is currently applied to the TDR in

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the following price control period (to offset the costs initially paid by demand consumers) would not occur such that the full costs would remain with consumers.

In addition, CMP344 would amend existing CUSC text to clarify when the allowed revenue of TOs and OFTOs will be set (i.e. each onshore price control period and at the point of asset transfer, respectively). This was proposed on the basis that the existing legal text of the CUSC does not recognise the differing revenue arrangements for TOs and OFTOs. This change would codify existing arrangements for the purpose of clarification and does not represent a change to the methodology that is currently applied.

The Proposer believes that, as compared to the current charging arrangements (the 'Baseline'), the Proposal better facilitates Applicable CUSC Objectives[12] ('ACOs') (d), (e) and (h), with a neutral impact on the remaining objectives. The Proposer considers that this change would allow offshore generators to compete on a level playing field with other forms of generation, and further considers that changing the recovery mechanism for IAEs would improve cost reflectivity. They state that CMP344 also reduces the complexity of the administration of TNUoS charges.

First Send back

The Final Modification Report (FMR) for CMP344 was submitted to the Authority for decision on 12 January 2021. On 5 May 2021, the Authority sent the FMR back and directed that the Panel resubmit the FMR on the basis that we were unable to properly form an opinion on the Proposal at that time.[13] Specifically, we considered that the first FMR did not specify which

[12] As set out in Standard Condition E2 of the Electricity System Operator Licence.
[13] Authority decision to send back CUSC modification proposal CMP344 'Changes to the way offshore transmission charges are shared between Users of the transmission system/generators and suppliers' (ofgem.gov.uk)

OFTO pass-through items the proposal intended to capture and we were unclear on the potential impacts given the FMR did not contain any quantitative evidence regarding how the change would impact different network users.

Following this, the Workgroup agreed that the scope of CMP344 would be limited to the treatment of costs related to IAEs only, and no other pass-through Items. The Proposer also commissioned Cornwall Insight to carry out analysis[14] (all references to 'analysis' in this decision are references to the three reports by Cornwall Insights: "CMP344 Modification Development Support", dated October 2022 and Annex 11 of the FMR; "CMP344 Modification Development Support – Summary of independent report", dated October 2022 and Annex 12 of the FMR; and "CMP344 Additional Workgroup Analysis", dated November 2024 and Annex 16 of the FMR) modelling the impacts that CMP344 (if implemented) could have on demand consumers' TNUoS charges if an IAE was approved in the future. The analysis also considered how removing generator liability for IAE costs could potentially impact future Contracts for Difference (CfD)[15] bids made by generators i.e., whether removing this perceived risk from generators (with demand consumers bearing the costs of any potential offshore IAEs) would reduce the risk premia offshore generators may include in their CfD bids (such risk premia serving to act as a mitigant for any variance between a generator's expected costs or revenues, and outturn values).

The analysis noted that IAE claims have been rare and that none had been approved by the Authority at the time the FMR was written. However, it concluded that the risk of IAEs occurring is likely to impact costs faced by consumers. Based on the assumption of a 1 in 50

[14] See Annex 11 and Annex 12 of the 3rd FMR
[15] A Contract for Difference, or CfD is a contract between a renewable generator and the 'Low Carbon Contracts Company' guaranteeing that the generator will receive a specific price for every unit of electricity they export. These contracts are awarded through a government auction into which generators bid, taking into account their projected revenues and liabilities including TNUoS.

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chance (central case) of an IAE with a £10m value occurring in any given year, the analysis presented estimated that:

- The risk of increased TNUoS charges for generators (in circumstances where an IAE was approved) could likely increase CfD strike prices by £0.03/MWh; and
- For upcoming (at the time of the FMR) anticipated CfD Allocation Rounds ('AR') 5, 6 and 7, the total benefit to consumers of implementing CMP344 would be approximately £52.9 million over the lifespan of the CfDs awarded, due to what the analysis considered could be reduced risk premia that would be applied when generators bid in the CfD auction(s); and
- If an IAE were to be approved following the implementation of CMP344, there would be a short-term cost to consumers which would offset benefits resulting from a reduction in risk premia. If, however, there were no IAEs, there would be no off-setting cost to consumers and consumers would receive the full benefit of the reduction in risk premia.

Second Send back

Although the Second FMR received on 8 February 2023 clarified the scope of the Proposal and, to a certain extent, provided the requested quantitative analysis, we concluded that the information contained in the Second FMR still lacked clarity; specifically in relation to the treatment of IAEs in the current charging arrangements and the extent to which the arrangements onshore and offshore currently differ and how such arrangements would be better aligned by approval of the Proposal. We also highlighted that in our view the quantitative analysis provided in the second FMR did not provide a well-rounded view of the impacts of CMP344, with respect to existing generators with CfD contracts. On 12 February

2024, the Authority sent the Second FMR back[16] and directed that the Panel resubmit the FMR addressing these points.

Third FMR

The Third FMR[17] for CMP344 was submitted to the Authority for decision on 9 July 2025.

CUSC Panel[18] recommendation

At the CUSC Panel meeting on 27 June 2025, the CUSC Panel (the 'Panel') by majority considered that CMP344 would better facilitate the ACOs than the baseline and therefore recommended its approval. Overall, they considered by majority that ACO (d) (facilitating effective competition) and ACO (h) (efficiency in the implementation and administration of the charging methodology) would be better facilitated but had no consensus view on whether ACO (e) (cost reflectivity in charges) would be better facilitated or not. Further details on the views of the Panel members and voting are set out in the Third FMR.

Our decision

We have considered the issues raised by the Proposal and the FMR dated 9 July 2025, taking account of the responses to the industry consultations on the Proposal. We have also taken into account the views expressed and the votes of the Workgroup and the CUSC Panel on CMP344. We have concluded that:

[16] Second Authority decision to send back Connection and Use of System Code (CUSC) Modification Proposal CMP344 'Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology'
[17] NESO: CMP344 3rd Final Modification Report.pdf
[18] The CUSC Panel is established and constituted from time to time pursuant to and in accordance with section 8 of the CUSC.

- implementation of the modification proposal will not better facilitate the achievement of the ACOs; and
- directing that the modification be made would not be consistent with our principal objective and statutory duties.[19]

Reasons for our decision

We consider the Proposal will have a negative impact on ACOs (d), (e) and (h) and a neutral impact on all other ACOs. Therefore, we have decided to reject CMP344 for the reasons set out below.

Our assessment against the ACOs:

(d) that compliance with the Use of System Charging Methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity

The Proposer considers the Proposal would be positive in regard to ACO (d), stating that the change would allow offshore generators to compete on a level playing field with other forms of generation that do not face the risk of IAEs being included in their local tariffs, and that it would allow offshore generators to more closely compete with each other on the basis of underlying project costs, rather than differences in expectation of the risk of IAEs occurring.

The majority of Panel members considered the Proposal to be positive against this objective. This was generally on the basis that aligning the treatment of onshore and offshore

[19] The Authority's statutory duties in this context are detailed mainly in the Electricity Act 1989 (in particular, but not limited to, section 3A) as amended.

generators in respect of unforeseeable events enables competition between onshore and offshore generators and ensures offshore generators can compete (e.g. for a subsidy under CfDs) on a consistent basis, rather than being differentiated by assumptions relating to IAE risk. One Panel member noted that they consider there is a clear risk to offshore generators who face unforecastable costs related to potential IAEs, and the Proposal ensures distortions are removed from these generators, therefore, improving competitiveness amongst generators.

The Proposer and Workgroup generally considered that aligning the treatment of offshore and onshore generators in respect of unforeseeable events would be beneficial to competition. We note that the differences between onshore and offshore cost recovery processes were discussed within the Workgroup and it was concluded by the Workgroup that the onshore equivalent of an IAE is a COAE.

The Workgroup also discussed what they considered to be another comparison between the IAE mechanism and the Scottish Hydro Electric Transmission Ltd (SHETL) subsea cable re-opener which only applies to SHETL. SHETL has a Special Licence Condition for Subsea Cable Reopeners[20] where there is a need for a subsea cable repair works on the licensee's transmission system.

We also note that one Code Administrator Consultation (CAC) respondent suggested that the Proposal is not sufficiently targeted, highlighting that the scope of the solution does not distinguish between offshore generators that may bid for CfDs in future Allocation Rounds, when compared to existing offshore CfD holders or offshore merchant generators. The respondent considers that implementation of the Proposal will represent a windfall gain for

[20] SHETP Special Licence Condition 3.28: [Electricity licensing (from October 2025) - Publications - Ofgem Public Register]

existing CfD holders who have already priced an IAE risk into their CfD bids, as implementing the Proposal would in theory result in those generators being compensated twice.

Our view

We set out below our assessment against this objective, focusing primarily on the points raised to support the Proposal alongside other major impacts or considerations that are evident to us.

We do not consider the Proposal would improve competition as compared to the baseline.

Equivalent position

We disagree that onshore and offshore generators are in an equivalent position, such that the mechanisms to recover additional costs incurred by the TO and OFTO should be recovered in an aligned and consistent manner i.e. from demand.

There are distinct differences between onshore and offshore generators in terms of the ability to mitigate both the risk of such events occurring and the impacts of such events in terms of cost arising. Whilst offshore generators may not always be able to avoid the risk of occurrence of an IAE (e.g., for an unforeseeable cable failure), they are the party best placed to mitigate the risk and its consequences. In principle, they can do so by procuring quality assets, providing relevant contractual protections (e.g. warranties and indemnities) and by negotiating requirements with the OFTO during the transaction phase (prior to the asset transfer) such as extended warranties or project specific indemnities. In contrast, an onshore generator cannot influence the quality or installation of the transmission assets provided to it by the TO or secure relevant commercial protections on the TO's behalf and as such cannot mitigate the risk of failure of these assets or the impact of the costs arising. We consider that this practical, commercial difference in design and operation is sufficient to warrant a differential in the cost recovery mechanism applying as between OFTOs and TOs should these assets fail and, in the case of OFTOs, an IAE is submitted and approved.

We would add that to the extent that there is a perceived onshore equivalent for an IAE, we observe that for onshore local circuit failures, the cost of the TO fixing or replacing the local circuit asset itself is recovered through onshore local circuit charges via an update to the SEF at the start of the following price control period. Onshore local charges are payable by generators and not demand consumers. This is in fact comparable to existing baseline arrangements for offshore local circuit charges (for example, if an IAE is awarded due to an offshore circuit failure the cost is recovered via an update to the generator offshore local circuit tariff and charges at the start of the next price control).

The Proposer and Workgroup made comparisons between IAEs and COAEs when discussing which aspects of onshore and offshore charging arrangements it was considered should be aligned. Whilst we recognise why respondents may have drawn this comparison, we do not consider these two mechanisms to be directly comparable. COAEs generally apply for unexpected costs related to the scope, cost and/or delivery impacts outside of a TO's control which will have an impact on the delivery of large network upgrade projects, such as[21] Large Onshore Transmission Investment ('LOTI') and Accelerated Strategic Transmission Investment ('ASTI') projects. ASTI and LOTI COAEs are used for events outside the licensee's reasonable control and for which the licensee could not have economically and efficiently

[21] Cost and Output Adjusting Events are defined in the Onshore Transmission Conditions. They are designed to recover costs for events outside the licensee's reasonable control such as extreme weather events, the imposition of additional terms or conditions of any statutory consent, approval or permission, unforeseen ground or sea-bed conditions and for the purposes of any particular LOTI Output. NGET and SHETP have additional conditions for specific project related COAEs: [Electricity licensing (from October 2025) - Publications - Ofgem Public Register]

planned a contingency which would impact the scope/cost of an ASTI/LOTI project delivery. Similarly to IAEs, COAEs require an approval from Ofgem.

The costs associated with COAEs relate to projects that are generally part of wider strategic works and/or projects required for security of supply and, as these costs cannot be attributed to a single user, are socialised and recovered through the TDR. In comparison, the costs of offshore IAEs are recovered from the offshore generator through offshore local circuit tariffs on the grounds that these costs relate to transmission assets, which are for the sole use of the offshore generator. As such, we do not consider that IAEs and COAEs are equivalent mechanisms nor that the cost recovery processes need to be aligned.

To the extent that comparisons were also drawn between IAEs and the SHETL subsea cable reopener, SHETL has not submitted a claim in respect of a subsea cable repair reopener. Whilst OFTOs usually own offshore transmission assets for use by offshore generators, we note that a TO's subsea cables (including SHETL subsea cable) are likely to be used for the wider network rather than being attributable to a specific generator. If a subsea cable claim was to be granted by Ofgem through SHETL's Subsea Cable Repairs Re-opener, the costs will be recovered from the TDR.

Overall, we do not consider the comparisons made by the Proposer and Workgroup sufficiently evidence that those specific onshore and offshore cost recovery mechanisms for unforeseeable events need to be aligned with each other, nor that more effective competition would specifically result from such alignment. IAEs are used to target events associated with assets used by a single generator whereas COAEs and certain specific re-openers are used to recover unexpected costs TOs face in relation to the wider network.

Cost reflectivity interactions – competition impact

We believe the current arrangements promote effective competition by ensuring generators are appropriately exposed to the costs they confer on the system.

We consider that it is appropriate to target the recovery of costs on the party that, relatively speaking, is more likely to drive those costs. Consumers do not drive the costs of offshore IAEs as the purpose of the assets in question (to which an IAE relate) are for the sole use of the offshore generator. Relatively speaking, offshore generators are more likely to be able to influence the quality or installation of the offshore transmission assets in the first place, and can to a degree mitigate the occurrence, and cost, of IAEs needing to be recovered by negotiating supplier warranties.

This approach is most likely to ensure competitive incentives for offshore generators to design and build their assets in a manner that mitigates the risk of asset failure, and to seek to negotiate supplier recourse as well as contractual protections, thus imposing lower transmission costs for consumers.

We would add that, removing the offshore generator's liability for the costs incurred by the OFTO for the repair or replacement of an asset built or procured by that same generator could in principle, in our view, negatively impact competition at the CfD bidding stage. We recognise that there will still be a strong commercial incentive for an offshore generator to ensure a quality build, whatever the ultimate treatment of IAEs, and to that extent this is a marginal consideration. However, if the generator's incentive to ensure quality build is reduced even to a very small degree, if any associated repair or replacement costs are moved to consumers who are unable to mitigate such risks, it is possible that this could lead to competitive distortions through artificially low CfD bids by some generators into auctions. This is because, in the event the transmission assets were to fail, the cost of those failures (in

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the context of IAEs) would be borne fully by consumers rather than the offshore generator which built the asset and is best placed to mitigate cost impacts through contractual protections (including those negotiated at the transaction phase prior to asset transfer) or warranties/indemnities.

For these reasons, we do not consider the Proposal to be conducive to effective competition in the market.

We recognise that as the market develops, it may not always be the generator in question who builds the relevant assets. It is possible that in some cases, in future, an OFTO will be appointed before construction to build the assets for a generator to use, similarly to the onshore arrangements today. This is hypothetical. We appreciate that under such a model the risk profile for an offshore generator may need to look different to today's arrangements. However, we consider this to be one of many current regulatory and financial differences that may require review if the role of an OFTO were to change. Our assessment of the Proposal is conducted against the current arrangements, where OFTOs purchase, rather than build transmission assets for generators and if there is to be a scenario where an OFTO builds rather than purchases assets, the principles of requiring good commercial recourse and ensuring quality build and installation will still apply.

<u>Impact on competition – CfDs and sale of electricity</u>

We note that whilst the second and third FMRs provide a view of potential CMP344 impacts in relation to CfD bids and consumer costs, our understanding and expectation remains that removing the costs of IAEs from offshore generators will not necessarily result in greater volumes of offshore generation entering the market and potentially better facilitating competition through improved liquidity in the CfD auctions. In addition, it is unclear that the level of risk premia assumed to be applied to CfD bids and alleged to be removed via the Proposal, for events considered as rare within the analysis, would be material enough to reduce CfD strike prices or meaningfully improve competitiveness.

Onshore vs offshore in the context of CfDs

In the context of CfDs, we do not consider that the Proposal would improve an offshore generator's ability to compete with other forms of generation. The current CfD regime recognises the material differences in cost structures for onshore and offshore wind, allocating separate 'pot' structures which group the separate technologies and use different core parameters. In the most recent Allocation Round, AR7, offshore wind, had a separate ascribed budget of £900m[22], compared to the £295m allocated for onshore wind. The different levels of CfD support are to address any underlying cost differentials between regimes and forms of generation. To the extent that offshore generators consider it prudent to factor in appropriate level of risk premium for potential IAEs, this will have been included within their bids and ultimately strike prices following any successful bids. This structure essentially prevents offshore projects from directly competing for subsidies against other technologies (i.e. onshore wind).

In relation to the resulting competition in the sale of electricity, we would observe that the effect of securing the different levels of subsidy (for onshore and offshore generators) for their respective CfD contracts is essentially to put them on a level playing field (by providing the 'missing money' to make their respective investments viable). As noted above, the different underlying cost structures to which they are each exposed (including IAEs) will have been factored into the relevant level of their CfD bids and once the subsidy is secured, they

[22] The budget for CfD AR7 was revised following the round, and the final budget for offshore wind was £1790 million, an overall increase of £890 million.

are each put in a comparable situation and able to compete effectively in the sale of electricity.

<u>Distortion of competition – between existing CfD generators and other generators</u>
Importantly, we agree with the CAC respondent who highlighted the risk that the Proposal could introduce a distortion, as the Proposal would apply to both existing and future CfD backed generation. If it is correct that generators will factor in a risk premia in respect of IAEs (under the current arrangements), it is expected to be the case that existing CfD holders will have benefited from a strike price that includes such risk premia. If the Proposal was implemented, existing CfD generators would therefore obtain the benefit of a strike price inflated to cover the costs of potential IAEs in respect of which (if they were to materialise) they would not face the costs. This would not be the case for future CfD backed generators (or indeed any other generators) and as such, would negatively impact competition (even if only to a marginal extent given the estimated value of the risk premia). In practice, this distortion would result in consumers continuing to fund risk premia for some existing projects, while also bearing IAE costs directly should one be awarded.

For all these reasons, we do not consider the Proposal would improve competition as compared to the baseline and, we conclude that the Proposal would result in a negative outcome for ACO (d).

(e) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C11 (Requirements of a Connect and Manage Connection);

With respect to ACO (e), the Proposer considers CMP344 would improve cost reflectivity. Its position is that IAEs do not constitute a signal that developers are able to respond to and there is no evidence to show that offshore generators are able to take any action to avoid the occurrence of IAEs. The Proposer states that offshore generators already have a very strong incentive to ensure a cable is constructed to an exceptionally high standard to avoid potential cable failures which could affect their ability to export power, thus leading to significant revenue losses. The Proposer also highlights that if a signal cannot be responded to then it is more efficient to place this risk directly onto demand.

Four out of nine Panel members considered the Proposal to better facilitate this objective, however, we note that two Panel members did not provide an overall voting statement and therefore no reasoning of why this ACO was better facilitated. Where reasoning was provided it was considered that the current treatment for IAEs does not provide a useful signal to offshore generators, who would still be incentivised to build reliable offshore networks to avoid outages. It was also stated that risks associated with IAEs should sit with parties best able to manage them and that, to date, there is no evidence that generators can mitigate the risk of IAEs and therefore it is appropriate to socialise the costs of such events.

Three Panel members considered the Proposal to be negative against this objective. One Panel member highlighted the Proposal places the impact of IAEs fully onto consumers rather than an individual generator, therefore, reducing the cost reflectiveness of charges and removes any incentive on generators to manage the risk. Another member highlighted that any potential benefit from better facilitating competition does so by making charges less cost reflective and likely leading to higher costs to end consumers and therefore worse outcomes.

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Two Panel members considered the Proposal to be neutral against this objective. One Panel member considered that there is a perceived improvement in terms of clarity in the way cost recovery is achieved between onshore and offshore generators. However, it was recognised that consumers will bear the risk of IAEs going forward, but considered that on balance, this may be an appropriate trade off.

Our view

We consider that it is important that generators benefitting from the network infrastructure are contributing fairly towards its operation and maintenance, and should receive charging signals that appropriately reflect the costs they confer on that network. As such we believe that targeting the recovery of costs on the party most likely to drive those costs or best placed to respond to a cost signal (for example the party that can to a degree mitigate the occurrence, and cost, of IAEs) is appropriate.

We consider the current arrangements to recover cost associated with an offshore IAE from the offshore generator to be more cost reflective than fully charging consumers who have no ability to manage those costs or respond to the signals.

Ability to mitigate risk of IAE occurrence/impact

We set out certain respects in which offshore generators may drive the costs of IAEs, and may be able to respond to cost signals in respect of IAEs, under ACO (d) above.

We do not agree with the views presented that offshore generators cannot mitigate the risk of IAEs and their associated costs and therefore can't act upon any potential signal. We consider offshore generators to be best placed to ensure appropriate arrangements are in place to reduce the risk of such events occurring by ensuring the quality of the assets and the installation, together with appropriate commercial recourse to mitigate the subsequent cost impacts of any such occurrence (through asset warranties, indemnities, and relevant contractual protections to be agreed as part of the transaction phase i.e. insurance). We consider that offshore generators are incentivised to ensure such arrangements and recourse for commercial reasons, as well as because of the IAE regime, and have taken this into account, but it remains our view that, overall, the Proposal would negatively impact cost reflectivity.

Assets for use of the offshore generator

Furthermore, we consider the current arrangements to recover cost associated with an offshore IAE from the offshore generator to be more cost reflective than fully charging consumers, as the assets in question are for the sole use of the offshore generator which is not the case with the onshore meshed network.

Generators do not always bear the full costs of IAEs

We also note that offshore generators do not always bear the full costs of IAEs.

The IAE framework now includes an insurance deductible, meaning the OFTO will bear some of the costs of the IAE (noting that an OFTOs inability to secure relevant insurance in the world-wide insurance market may contribute to the approval of an IAE by the Authority).

Additionally, as explained above, there may already well be, in some instances, a consumer contribution to the costs of the offshore assets where the generator has built or procured oversized transmission assets in comparison to its required capacity. In such circumstances, if an IAE were to be approved and the OFTO's TRS adjusted to reflect this, both the offshore generator and consumer will contribute to the cost of the IAE.

This reinforces our view that the cost of an IAE should be shared (although not equally) across the offshore generator, OFTO (through relevant insurance deductibles, if available) and consumers (where the assets are oversized). We consider that the full removal of an offshore generator's liability in relation to IAE costs and instead socialising these (with full recovery from end consumers) would be less cost reflective.

For all these reasons, we conclude that the Proposal is negative against ACO (e).

(f) that the Use of System Charging Methodology, as far as is reasonably practicable, properly takes account of the developments in Transmission Licensees' Transmission Businesses and the ISOP Business;[23]

The Proposer and all Panel members considered the Proposal to be neutral in regard to ACO (f), however no reasoning was provided.

Our view

We consider that the Proposal will not directly impact the charging methodologies' ability to reflect changes in transmission licensees' businesses. Therefore, we conclude that the Proposal has a neutral impact on ACO (f).

[23] Electricity System Operator Licence

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(g) compliance with the Electricity Regulation and any Relevant Legally Binding Decisions of the European Commission and/or the Agency[24]

The Proposer and all Panel members considered the Proposal to be neutral in regard to ACO (g), however no reasoning was provided.

Our view

We consider that the Proposal does not engage this objective and is therefore neutral in relation to ACO (g).

(h) promoting efficiency in the implementation and administration of the Use of System Charging Methodology

The Proposer considers that the Proposal would be positive in regard to ACO (h) as it would bring clarity to something which is not currently addressed in the CUSC. They also state that the Proposal will reduce the complexity of the administration of TNUoS charges as it creates a single stage recovery mechanism from demand users, rather than the current two-stage recovery.

The majority of Panel members considered the Proposal better facilitated ACO (h), highlighting that it clarifies the approach with respect to IAEs which in turn is judged to improve efficiency. It was considered that the Proposal introduces an efficient mechanism for reflecting changes in revenue associated with IAEs and removes any potential ambiguity

[24] The Electricity Regulation referred to in objective (g) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it had effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006

in the CUSC. It should be noted however that two of the Panel members that considered the change to be positive provided no voting statement and therefore no rationale for their view.

Our view

There are two aspects to the Proposal: clarifying existing arrangements in respect of the point in time at which the OFTO TRS and TO allowed revenues are set; and introducing new wording to the CUSC to transfer the full liability for offshore IAEs from offshore generators to consumers. The stated purpose of this proposal is to “clarify” arrangements, but clearly the overall effect of it would be significantly broader, in particular in transferring liability to pay costs associated with IAEs from offshore generators to consumers.

Were this proposal seeking solely to enshrine within CUSC an established process we would likely agree that it was positive against ACO (h).

The assessment is less straightforward in respect of the proposed transfer of liability for IAE costs from offshore generators to consumers. We do recognise that removing demonstrably unnecessary steps in the charging methodology would ordinarily simplify the process and in that respect may be considered to improve efficiency. However, as set out in the sections above, we believe that the current process should be maintained. Therefore, updating the methodology to explicitly provide for a different process would be inefficient and as such detrimental to the effectiveness of the charging methodology overall.

We therefore conclude that the Proposal would have a negative impact on ACO (h).

Assessment against the Authority’s principal objectives and statutory duties

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Having concluded that the assessment against the objectives is overall negative, section 8.23.7 of the CUSC provides that there shall be no approval. For completeness, however, we note that we consider that rejecting the Proposal is also consistent with our statutory duties, including our principal objective to protect the interests of existing and future consumers.

We have already addressed several factors above which indicate that the Proposal does not protect the interests of existing and future consumers).

We have also carefully considered the analysis supplied by Cornwall Insight.

However, that analysis (and Cornwall Insight's conclusion as to resulting consumer benefits through removal of risk premia) was premised on the Proposal being implemented prior to CfD Allocation Rounds AR5, AR6 and AR7 commencing. We note that AR5, AR6 and AR7 have now taken place. Generators included in these allocation rounds will already have their CfD strike price (reflecting, at the point of bidding any anticipated risk premia) contractually fixed. This affects the accuracy of Cornwall Insight's conclusions. It also means that (as the Proposal would apply to existing and future generators) there is an increased risk that, should CMP344 be implemented, consumers would (in effect) face a double burden in relation to the costs of an approved IAE: once through the risk premium already included in the bids and subsequent strike price, and again through recovery via the TDR. We do not consider this to be in the interests of consumers.

In addition, we consider that there are limitations in the Cornwall Insight analysis. We acknowledge that Cornwall Insight have set out sensitivities to give a view of uncertainties. However, we also note that the analysis makes a number of simplifying assumptions of how an IAE is funded in practice, which are not fully correct. In particular, the analysis does not reflect certain aspects of the existing IAE cost recovery mechanism, including the treatment of OFTO insurance deductibles or the potential for the sharing of the awarded IAE cost between parties (i.e., reflecting the fact that consumers may also bear the costs associated with oversized offshore assets). As such, it is unclear how accurate the analysis provided is in terms of the magnitude of likely risk reductions (noting the Cornwall Insights analysis itself states that "[...] this is not an exact science").

Given these limitations, we consider it unlikely, or at least uncertain, that the overall net consumer savings identified by Cornwall Insight will materialise in practice and do not consider it to be in consumer interests that they potentially require to face a double burden in respect of IAEs for existing CfD generators (both in terms of an inflated strike price and the resulting costs flowing from an IAE).

As stated above, we conclude the assessment against the ACO's is overall negative, but in any event, we do not consider the Proposal would be consistent with our principal objective and wider statutory duties.

Decision notice

In accordance with Standard Condition E2 of the Electricity System Operator Licence, the Authority has decided that modification proposal CUSC CMP344: *Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology* should not be made.

James Stone

Head of Electricity Network Charging - Energy Systems Management & Security

Signed on behalf of the Authority and authorised for that purpose