NESO
National Energy System Operator

Second Code Administrator Consultation

CMP418:

Refine the allocation of Dynamic Reactive Compensation Equipment (DRCE) costs at OFTO transfer

Overview: Modification of the DRCE cost allocation for offshore wind farms. The proposal seeks to move the cost of DRCE from the offshore local circuit tariff to the onshore substation tariff. Instead of the current system where offshore wind farm Generators both (i) provide upfront capital costs for the DRCE before transferring to OFTO and (ii) cover the cost of DRCE via the offshore local circuit tariff for the lifetime of the project.

Modification process & timetable

1. **Proposal Form**
   02 August 2023
2. **Workgroup Consultation**
   02 January 2024 - 22 January 2024
3. **Workgroup Report**
   15 February 2024
4. **First Code Administrator Consultation**
   29 February 2024 - 21 March 2024
5. **First Final Modification Report**
   06 May 2024
6. **Second Code Administrator Consultation**
   29 January 2025 - 19 February 2025
7. **Second Draft Final Modification Report**
   20 February 2025
8. **Second Final Modification Report**
   11 March 2025
9. **Implementation**
   01 April 2025

Have 5 minutes? Read our Executive summary

Have 20 minutes? Read the full Second Code Administrator Consultation Report

Have 30 minutes? Read the full Second Code Administrator Consultation and Annexes.

Status summary: On 30 September 2024, the Authority sent back CMP418 and directed that the Panel re-submit the Final Modification Report (FMR). The Panel on 25 October 2024 agreed next steps for the Workgroup to address we are now consulting on this proposed change.

This modification is expected to have a: Medium impact on Offshore Wind Farm Generators

Governance route	A Standard Governance modification has been assessed by a Workgroup	
Who can I talk to about the change?	**Proposer:** Giulia Licocci Giulia.licocci@oceanwinds.com +34604986702	**Code Administrator Chair:** Claire Goult Claire.goult@nationalgrideso.com 07938737807
How do I respond?	Send your response proforma to cusc.team@nationalenergyso.com by **5pm** on **19 February 2025**	

Contents

Executive summary

What is the issue?

There is a defect against the CUSC charging objectives regarding the treatment of dynamic reactive compensation equipment (DRCE) which creates a commercial imbalance between offshore and onshore generators.

What is the solution and when will it come into effect?

Proposer's solution: CMP418 seeks to address this defect by removing DRCE costs from the offshore generator's TNUoS tariff.

Implementation date: 1 April 2025

Workgroup conclusions: The Workgroup concluded unanimously that the Original Proposal better facilitated the Applicable Objectives than the Baseline.

What is the impact if this change is made?

- Provides a more equitable commercial environment for onshore and offshore generators regarding cost exposure and revenue recovery for DRCE, thus facilitating competition and creating a level playing field.
- Lower offshore TNUoS charges would reduce financial barriers for future offshore wind developers.
- OFTOs will not be financially impacted by this mod (NESO will merely recover the part of OFTO income that relates to DRCE from the Transmission Demand Residual instead).
- The introduction of CMP418 is expected to increase the TDR revenue collection by approximately £298 million by 2050 (Consumers will pay for the cost of DRCE related to offshore generators as they do for other generators via ORPS)
- However this amount is expected to be offset by a reduction of £262m to the CfD levy by 2050, leaving a net consumer impact of £35.8m annually, which represents a 1.03% increase when compared to the £3,471.8m of TDR revenue collected from demand users in charging year 2023/2024. It is not foreseen that this modification interacts with other codes, industry documents, modifications, or industry projects.

What is the issue?

There is a defect against the CUSC charging objectives regarding the treatment of dynamic reactive compensation equipment (DRCE) which creates a commercial imbalance between offshore and onshore generators.

The defect arises due to the impact of the offshore transmission owner (OFTO) regime on offshore generators. Specifically, the transfer of DRCE assets from the generator to the OFTO removes the opportunity for offshore generators to offer services in the Obligatory Reactive Power Service (ORPS). In addition, offshore generators are exposed to the capital cost of DRCE through their offshore Transmission and Use of System Charges (TNUoS) for the lifetime of their project.

In contrast, onshore generators retain ownership of DRCE and can provide services to the ORPS for which they receive financial compensation by the NESO under the balancing services mechanism.

This proposal would implement a minor change to the existing cost recovery regime to remove DRCE from offshore generators TNUoS charge, thereby providing a more commercially equitable position with onshore generators. This improves compliance with CUSC objective (a), promoting effective competition in the generation and supply of electricity.

Background

All transmission-connected generators that operate over 47MW are required to have the capability to provide reactive power support, typically using DRCE operating in voltage control mode to maintain network stability at the Grid Entry Point (GEP)[1]. This obligation applies to both onshore and offshore wind farms.

Network stability services are classified as ancillary services under BC2.A.2 and are compensated through the ORPS. Generators who provide this service are paid according to their Mandatory Services Agreement (MSA) via the Default Payment Arrangements, in £/MVArh. The provider will be paid from the date that the MSA is signed. This is regardless of whether or not they are instructed for reactive power, as the provider will naturally drift between leading or lagging rather than constantly staying at zero MVar.[2].

[1] file:///C:/Users/OW000273/Downloads/obligatory-reactive-power-guide.pdf
[2] Link to NESO website

All eligible onshore generators can therefore mitigate the capital cost of installing DRCE equipment for their contribution to system-wide reactive power support.

However, offshore transmission connected generators are subject to the Offshore Transmission Owner (OFTO) regime, which transfers DRCE ownership, and responsibility to fulfil the associated grid code obligations, to the OFTO. Offshore generators are therefore precluded from participation in the ORPS and cannot recover financial compensation for the cost of installing DRCE.

OFTOs are obliged to provide this reactive power service, but cannot recover costs through the ORPS. However, they are financially compensated through their tender revenue stream (TRS). The offshore generator funds the TRS through its offshore TNUoS charge so remains exposed to the capital and operating costs of installing the DRCE.

Consequently, there is a commercial imbalance for offshore generators who must cover DRCE costs through their offshore TNUoS charges but cannot recover compensation through the ORPS, unlike their onshore counterparts who can receive ORPS payments. Offshore generators are therefore competing on an unequitable basis with onshore generators and this defect in the charging methodology is what this proposal seeks to resolve.

1. Introduction

Both onshore and offshore wind farms are mandated to provide reactive power services in compliance with Grid Code regulations. To fulfill these requirements, both types of wind farms typically install DRCE.

For offshore wind farms, the DRCE they install is transferred to the OFTO at the OFTO Transaction. In contrast, onshore wind farms retain ownership of their DRCE and receive financial compensation for this ancillary service through the ORPS. Consequently, offshore wind farms incur costs by paying the OFTO through offshore TNUoS charges, whereas onshore wind farms benefit from direct compensation for their reactive power services.

- The onshore windfarm installs the DRCE, owns the DRCE and is paid to provide reactive power services.
- The offshore windfarm installs the DRCE, transfers it to the OFTO, and pays offshore TNUoS charges specific to the cost of the DRCE for the lifetime of the project (via the offshore local circuit tariff).

2. Technical background – Different technical networks

There are substantial differences between the onshore and offshore networks. Onshore, the transmission system is dominated by overhead lines and is heavily meshed, whereas in offshore networks (as currently used on the GB Transmission System) they are dominated by undersea cables and use radial networks (i.e. not meshed/interconnected). These differences have a huge impact on reactive power and explain why onshore and offshore wind farms use different approaches to manage reactive power services needed to keep the electricity grid stable and to fulfill the Grid Code requirements.

Onshore wind farms use overhead high-voltage AC lines that are interconnected in a complex, mesh-like pattern. This setup allows them to sometimes manage reactive power with their Wind Turbine Generators (WTGs) and install DRCE when the WTGs cannot meet the full Grid Code requirements on their own. Onshore wind farms maintain ownership of their DRCE and receive payments for these services through the ORPS.

In contrast, offshore wind farms are connected to the transmission system via export cables, long undersea high-voltage AC cables arranged in a radial pattern without inter-connection. These cables have high capacitance, which means they store more electrical energy and cause significant voltage changes along the cable. For this reason, offshore developers **also install shunt reactors** to compensate for these very high capacitances, in addition to the DRCE, to ensure all Grid Code requirements are met. Additionally, because of these long cable lengths and the challenges they create, it is more efficient to place the reactive power requirements onshore, which—after the OFTO transaction—becomes the responsibility of the OFTO, rather than requiring the offshore wind farm to handle them directly.

Technical background – Grid Code requirements

The Grid Code (Issue 6, revision 28, 7 November 2024)[3] sets out the mandatory reactive compensation requirements for large generators. The requirements stem from the technical differences between onshore and offshore generators.

The ownership boundaries of the wind farm/generator, OFTO, and onshore network operator are shown in Diagram 1.

[3] NESO, The Grid Code, 2024 source: [Grid code documents]

OFFSHORE:

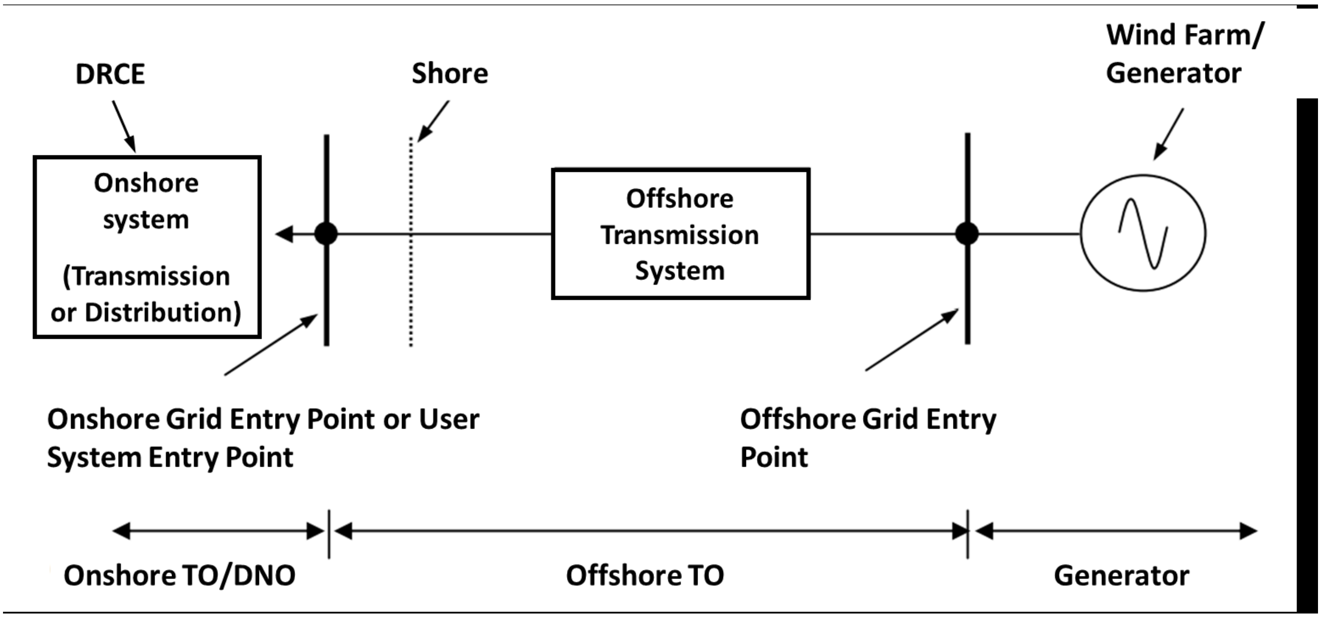


Diagram 1 - Designation of offshore wind farm boundaries[4]

ECC.6.3.2.5.1 sets out the requirement that the offshore wind farm must:

- *Maintain zero reactive power transfer at the Offshore Grid Entry Point (GEP) at all active power levels under steady-state voltage conditions, with a steady-state tolerance no greater than 5% of the Rated MW.*

Because of the capacitances of the long offshore export cables, offshore generators are required to meet zero reactive power at the Offshore Grid Entry Point (GEP).

This requirement is met by using a combination of offshore generator reactive power capability (WTG) to compensate for the inductance of the inter-array cables to achieve zero reactive transfer at the offshore GEP.

ONSHORE:

ECC.6.3.2.4.4 sets out the requirement that onshore wind farms and, in the case of offshore wind farms, OFTOs must comply with:

- Supply the rated MW output between the limits of 0.95 power factor lagging and 0.95 power factor leading at the onshore GEP, with the former requiring absorption of Vars from the grid and the latter requiring the injection of Vars.

[4] Offshore Transmission Expert Group — Great Britain Security and Quality of Supply sub-group. Recommendations for the coverage of offshore transmission networks in the Great Britain Security and Quality of Supply Standard, 2006

- The reactive power limits defined at rated MW at lagging power factor will apply at all active power output levels above 20% of the rated MW output as defined in Figure 1.
- The reactive power limits defined at rated MW at leading power factor will apply at all active power output levels above 50% of the rated MW output as defined in Figure 1.
- The reactive power limits will reduce linearly below 50% Active Power output as shown in **Error! Reference source not found.**.

These requirements are met through the use of DRCE for offshore wind farms. In the case of onshore assets, wind turbine generators (WTGs) may provide some contribution to the onshore reactive power requirements in combination with the DRCE. This is not achievable for the large majority of offshore wind farms (as these assets are all located much further than 0.5 miles from shore, which means the capacitances of the offshore export cables come into play). The DRCE is then used to achieve the OFTO ±0.95 p.f. Grid Code requirement at the Onshore GEP under steady state and dynamic conditions. The absorption or delivery of reactive power from the DRCE is continuously adjusted to meet the GEP requirement for reactive power flow.

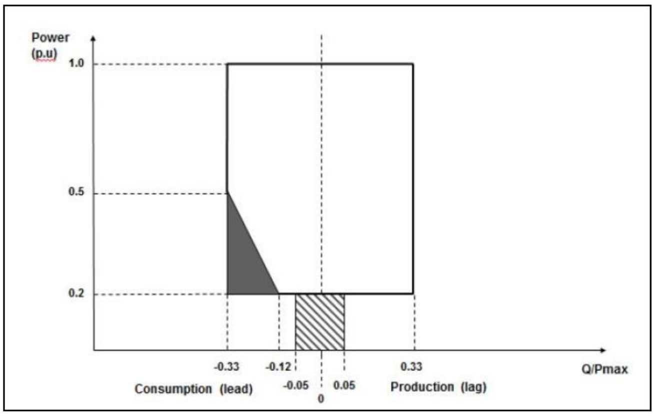


Figure 1 - Reactive power capability requirements

The reactive power requirements are placed on the OFTO rather than the offshore wind farm because it is not efficient for the wind farm to comply with the normal generator dynamic reactive compensation requirements offshore due to the long offshore export cable lengths.

A summary of the Grid Code requirements is provided in Table 1 below.

Grid Code reference	Requirement	How is it achieved?
CC.6.3.2(e)(i) Offshore Generator Requirement	Radially connected offshore windfarms are required to maintain zero reactive transfer at the Offshore Grid Entry Point	Generators typically use the reactive capability of the WTGs to compensate for the inductance of the inter-array cables and achieve zero reactive transfer at the offshore grid entry point. Shunt reactors/switched reactors are used to compensate for the offshore export cables.
CC.6.3.2 (c) OFTO Requirement	The OFTO is required to maintain 0.95 power factor lagging and 0.95 power factor leading at the Onshore Interface Point	This is achieved via the installation of DRCE. The absorption or delivery of reactive power from the SVC is continuously adjusted to meet the requirement for reactive power flow

Table 1- Grid Code Requirements for Reactive Power

3. Dynamic Reactive Compensation Equipment (DRCE)

Difference between DRCE and Shunt Reactors
A fixed shunt reactor and DRCE are both tools used to manage reactive power in electrical systems, but they work differently. A fixed shunt reactor is like a simple valve that always absorbs a set amount of reactive power to help control voltage levels, especially in long transmission lines. It doesn't change its operation based on the system's needs. On the other hand, DRCE is more like an adjustable faucet that can either add or remove reactive power as needed. This flexibility allows the DRCE to quickly respond to changes in the grid, helping to keep voltage levels stable and improve overall system reliability. In short, while shunt reactors provide a constant level of support, DRCE can adapt to varying conditions for better voltage control. (Please see Annex 6 for a comprehensive definition of DRCE).

The Grid code defines DRCE as "Plant and Apparatus capable of injecting or absorbing Reactive Power in a controlled manner which includes but is not limited to Synchronous Compensators, Static Var Compensators (SVC), or STATCOM devices. The Proposer of CMP418 is in the process of raising an additional modification to add the definition of DRCE to the CUSC.

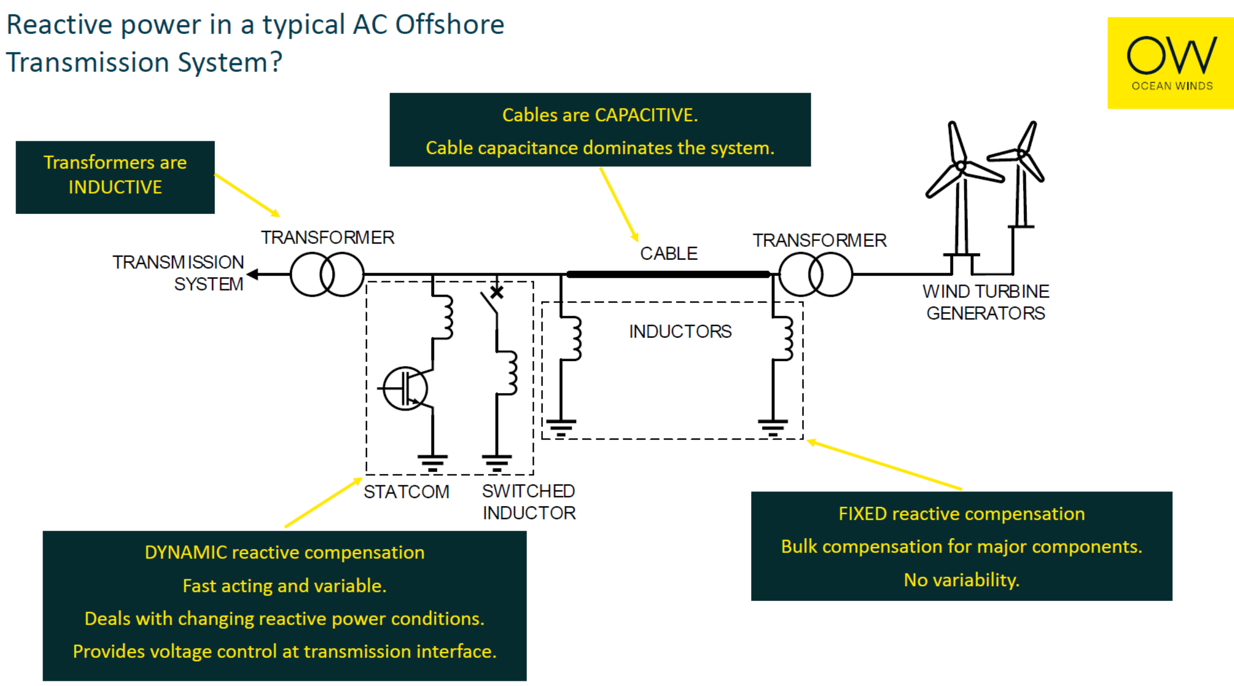
DCRE are indispensable components in power systems, as they provide reactive power compensation and help maintain grid stability. Reactive power is crucial for ensuring voltage levels remain within acceptable limits and is required for the reliable and efficient operation of power systems. Currently, all HVAC-connected offshore wind farms require DRCEs to meet grid code compliance concerning reactive compensation.

A traditional shunt reactor is not classified as DCRE. It is an absorber of reactive power, thus, increasing the energy efficiency of the system. It is the most compact device commonly used for reactive power compensation in long high-voltage transmission lines and in cable systems. The shunt reactor can be directly connected to the power line or to a tertiary winding of a three-winding transformer.

A shunt reactor could be permanently connected or switched via a circuit breaker. Fixed shunt reactors (or potentially a combination of fixed shunt reactors and switched reactors) are used by generators to compensate for cable capacitance of the offshore export cables (See Figure 2 below and **Annex 3** for more information)

Under this proposal only the capital cost of the DRCE will be removed from the local circuit tariff and added to the substation tariff at OFTO transaction. This is to reflect the purpose and capability of the DRCE equipment to provide varying reactive power output services to NESO to mitigate transmission system conditions as required under the ORPS. The cost of shunt reactors or similar equipment installed for this purpose will be retained within the local circuit tariff as it is appropriate for the offshore generator to retain exposure to the costs of this equipment.

Figure 2 Reactive power in a typical AC Offshore Transmission System



4. Commercial Background and Differences

All transmission-connected generators that operate over 47MW are required to have the capability to provide reactive power support, typically using DRCE operating in voltage control mode to maintain network stability at GEP. This obligation applies to both onshore and offshore wind farms.

Network stability services are classified as ancillary services under BC2.A.2 and are compensated through the ORPS. The ORPS is the provision of mandatory varying Reactive Power output such that at any given output generators may be requested to produce or absorb reactive power to help manage system voltages close to its point of connection. Generally, all transmission connected generators over 47MW are required to have the capability to provide this service, as set out in the Grid Code[5].

Generators are generally instructed by NESO to a target MVAr level that must be reached within 2 minutes. This target will sit within the Reactive Performance capability of the Generator. Instructions for Reactive Power are normally sent from National Grid to the Generator via an Electronic Dispatch Logging (EDL) system.

The ORPS is paid via the Default Payment Arrangements, outlined below. The contractual form of the service is captured in the MSA.

Under the Default Payment Mechanism, National Grid pays all service providers for utilisation in £/MVArh. This utilisation payment is updated monthly in line with market indicators as set out in Schedule 3 of the CUSC.

The provider will be paid from the date that the MSA is signed. This is regardless of whether or not they are instructed for reactive power, as the provider will naturally drift between leading or lagging rather than constantly staying at zero MVar.

However, offshore transmission connected generators are subject to the OFTO regime, which transfers DRCE ownership, and responsibility to fulfil the associated grid code obligations, to the OFTO. Offshore generators are therefore precluded from participation in the ORPS and cannot recover financial compensation for the cost of installing DRCE.

This proposal recognizes the technical differences in onshore and offshore electrical systems and seeks only to resolve the commercial inequality experienced by onshore and offshore generators due to the OFTO regime.

Both onshore and offshore wind farms may require installing DRCEs to enable compliance with the mandatory reactive compensation requirements to maintain 0.95 power factor lagging and 0.95 power factor leading at the onshore GEP (Grid Code CC.6.3.2 (c)).

[5] national grid document - Reactive Power – Obligatory (Non-Synchronous Generation)

In the case of onshore wind farms, the DRCE stays in the generator's ownership and financial mitigation for the capital cost can be recovered through the ORPS. In the case of offshore wind farms, the DRCE is transferred to the OFTO and the capital cost levied on the offshore generators through offshore TNUoS for the asset's lifetime with no financial compensation available through participation in ORPS

This difference means that while onshore wind farms are financially rewarded for their reactive power support, offshore wind farms bear the costs without equivalent compensation. CMP418 seeks to remove the capital cost of DRCE cost from offshore generators that is used by the NESO to provide reactive compensation on the transmission system. This would recognize that:

- Offshore generators install DRCE, this is transferred to the OFTO at OFTO transaction. The generator pays TNUoS for the lifetime of the offshore windfarm.
- Offshore generators meet their offshore GEP requirements with the WTGs.
- Offshore generators also install shunt reactors, which compensate for the high capacitances created by long-export cables.
- After OFTO transaction, OFTOs are required to meet the obligations of ECC.6.3.2.4.4, because at this point the onshore GEP is the OFTOs responsibility.
- As part of Standard Licence Condition E15, OFTOs are already paid for providing transmission services as part of their base transmission revenue (**Annex 8**).

Shunt reactors are not included in this proposal as these typically provide reactive compensation for the offshore export cables and do not provide dynamic reactive power support to the NESO.

	Installs DRCE?	Who owns DRCE?	Pays the cost of DRCE in TNUoS?	Who is paid via the Obligatory Reactive Power Service (ORPS) ?
Onshore Windfarm	Yes if the WTGs cannot meet the full Grid Code requirements on their own	Onshore Windfarm	No	Onshore Windfarms
Offshore Windfarm	Yes unless it is very close to shore (e.g. 0.5 miles)	Offshore Transmission Owners after OFTO transaction	Yes	OFTO - Remunerated as part of the Base revenue

Table 2 - technical and commercial treatment of DRCE

Why change?

The current regulatory regime requires the offshore wind developer to bear the cost of the DRCE installed at the onshore substation via offshore TNUoS charges, creating a commercially uncompetitive advantage against the onshore counterpart.

During the OFTO Transaction, the DRCE is transferred to the OFTO owner and is paid by the OFTO to the developer via the Final Transfer Value (FTV). The cost of DRCE and shunt reactors are then transformed into an offshore TNUoS charge and are paid solely by the offshore developer to the OFTO for the lifetime of the asset (see Figure 3 and 4).

However, after the OFTO transfer, an offshore wind farm's GEP is offshore, and the DRCE is not used for compliance for the wind farm at this GEP.

Therefore, while it is appropriate that shunt reactor costs fall into the local circuit tariff, as they serve to compensate for the technical differences specific to the offshore network, it should not follow that DRCE is treated in the same way.

Ultimately, shunt reactors are used by Generators to compensate for cable capacitance, while the DRCE is deployed by NESO to achieve voltage control on the grid network, for which the generator is not compensated but retains the financial exposure of the capital cost of installing DRCE through its offshore TNUOS charge, which is paid directly to the OFTO.

The change in approach and change in the allocation of DRCE costs is consistent with CUSC objectives because it promotes competition by providing a more equitable allocation of costs and benefits arising to offshore and onshore generators.

The cost for the provision of reactive compensation by onshore windfarms is remunerated via the ORPS payment, this is funded by Balancing Services Use of System (BSUoS) charges, which is paid by demand (end customers). The modification proposed under CMP418 would harmonise the treatment between onshore and offshore generators as the cost for the provision of reactive compensation by OFTOs would now be funded by demand (end customers) through the Transmission Demand Residual (TDR) instead of the offshore generator via offshore TNuoS (See figure 5)

Accordingly, the proposed solution under CMP418 facilitates effective competition in the generation of electricity while also encouraging the development of renewable energy sources, and potentially lowering energy prices.

Ocean Winds engaged with the wider industry through presentations in the Transmission charging Methodology Forum (TCMF) as well as with Scottish Renewables and Renewable UK and via one to one with various other developers. There is consensus that the current allocation of DRCE costs does not reflect OFTOs and Generators mandatory requirements under the Grid Code and poses a defect within the CUSC methodology.

Status quo:

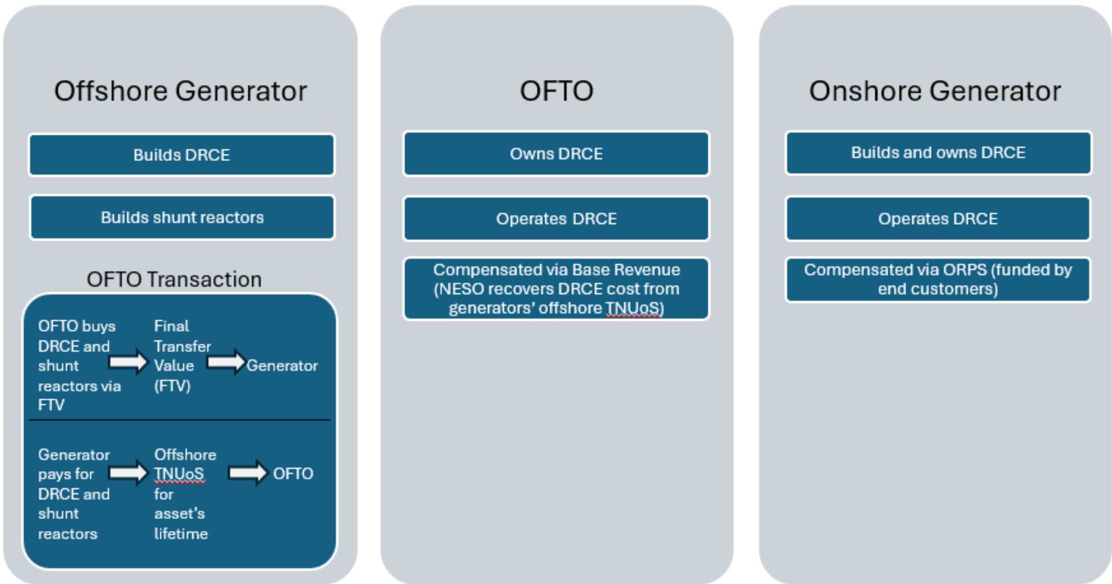


Figure 1 Status quo DRCE treatment

Proposed solution:

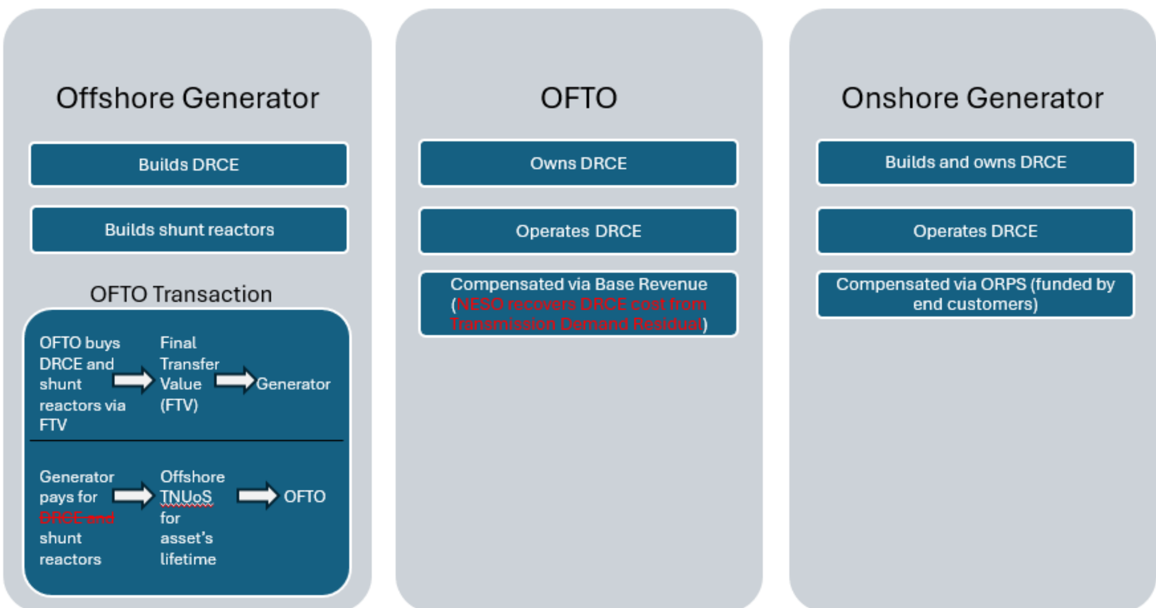


Figure 2 Proposed solution DRCE treatment

This proposal takes due regard of the technical differences experienced by offshore and onshore generation through the high capacitances associated with export cables for offshore sites compared to onshore sites. The offshore generator will remain responsible for the capital cost of the shunt reactors required to compensate the capacitances of the export cables. The cost of shunt reactors will be included in the OFTO transaction in the local circuit tariff and continue to be charged through offshore TNUoS to the generator. This proposal only removes the cost of DRCE, which provides the variable reactive compensation to the NESO. This provides appropriate alignment with the treatment of onshore generators. Onshore generators and OFTOs will not be impacted by this change.

What is the solution?

Proposer's solution

The recommendation updates the current OFTO TNUoS arrangements, ensuring a more equitable commercial treatment between onshore and offshore generators, through the proposed change to the charging methodology of the CUSC. This proposal will achieve a more appropriate allocation of DRCE costs supporting the future development and integration of offshore wind farms essential to achieving a decarbonised electricity system.

Specifically, for the calculation of offshore TNUoS costs, from Implementation Date forward, the cost of the DRCE is moved out of the 'circuit tariff" element and moved to the "onshore tariff" element, see Table 3 below.

Example calculation of offshore local tariffs

The table below shows how the capital costs of the offshore assets are converted into local tariffs. In this example, the generator has 400MW of TEC, and the circuit is a single cable (non-redundant – security factor of 1). The total OFTOt (annual OFTO revenue) is £25m.

		Capital Cost	Percentage of Total Capital Costs	Amount of OFTOt	Rating / Capability	Local Security Factor	Tariff
		(£k)		(£)	(MVA)		(£/kW)
Circuit	Offshore cable	100,000					
	Harmonic filtering equipment	1,000					
	Reactive plant	15,000					
	Circuit	**116,000**	**38%**	**9,555,189**	**420**	**1**	**22.750451**
Offshore Substation	Transformer	10,000	3%	823,723	640		1.287068
	Switchgear	2,500	1%	205,931	680		0.302839
	Platform	125,000	41%	10,296,540	640		16.088344
	Onshore civils cost adjustment[1]						-0.665605
	Substation	**137,500**	**45%**	**11,326,194**			**17.012646**
Other	Onshore substation	50,000	16%	4,118,616			Not Applicable
	Other	**50,000**	**16%**	**4,118,616**			Not Applicable
	TOTAL CAPITAL COST	**303,500**					
					LOCAL OFFSHORE TARIFF		**39.763097**

Table 3 – Example of current local offshore circuit tariff calculation

The costs falling into "Onshore Tariff" are ultimately socialised through the TDR. For further information on the estimated impact of the proposed change on the TDR, **(see Annex 7).**

Table 3 above is extracted from NESO's guidance document "TNUoS charging for offshore generators and the Offshore Transmission Owner regime.[6]" This shows how the local offshore tariff is typically calculated and that the onshore substation element is excluded. The cost of DCRE equipment would be moved into this category.

In the above example the capital cost and installation of DRCE would be moved from the £15,000k reactive plant value to the £50,000k onshore substation value.

At OFTO transaction, the value of the OFTO assets built by the developer are paid back to the generator by the OFTO through the Final transfer Value (FTV).

The FTV informs how much Tender Revenue Stream (TRS) the OFTO will receive as a fee for the generator to use the OFTO assets. This fee, the TRS, is largely calculated based on the cost of the OFTO assets (Offshore Substation + Circuit Tariff from Table 3), and for the generator is what constitutes the Offshore TNUoS charge.

When calculating how much the generator will have to pay to the OFTO, the costs of the entire OFTO assets are allocated between (See table 4):

- **Offshore generator charges**, split between the Offshore Circuit Tariff and Offshore Substation Tariff, and paid solely by the generator and.
- **Onshore Tariff**, this constitutes a very small part of the overall cost and is socialised via the wider tariff.
- As confirmed by the ESO revenue team, charges for unshared offshore circuits (within which lie DRCE costs in appropriate cases, under baseline) will normally, in the case by case assessment that is made by NESO, be classified, for the purpose of EC838/2010 when calculating the generation adjustment charge, as physical assets required for connection (PARC), and therefore should be excluded when calculating how much revenue is being collected from Generators for the purpose of the EU Cap. Hence, for the purpose of CMP418, we expect the cost of DRCE to be moved into the Transmission Demand Residual.

- Hence for the purpose of CMP418's proposal, the cost of the DRCE assets is moved from the "Offshore Circuit" tariff to the "Onshore Substation" tariff, which results in socialising these costs from specific generators to all demand users through the transmission demand residual.

[6] NESO Guidance document

Table 4 OFTO transaction offshore TNUoS cost allocation

Cost allocation	Tariff	Asset/Cost category
Offshore Generator	Circuit Tariff	Cable
		Cable Assets
		Reactive Equipment
		Harmonic Filtering Equipment
		HVDC Converter Station
	Substation Tariff	Transformer Assets
		Switchgear Assets
		Platform
		Auxillary Supply Equipment
Socialised	Onshore tariff	Onshore Substation

5. Consumer Impact (Annex 7)

As explained above, CMP418 seeks to align the commercial treatment of DRCE cost with the onshore precedent. The proposed change will shift the recovery of OFTO DRCE costs from the offshore generator to final consumers.

Today, at OFTO transaction, the DRCE cost falls into the "Local Circuit" element of offshore TNUoS, which is paid entirely by the offshore generator. The proposal is to move the DRCE cost to "Onshore Substation" element of offshore TNUoS, this cost is socialized across TNUoS customers. However, for the purpose of CMP418, we expect that moving the DRCE cost to the onshore substation element of offshore TNUoS is equivalent to moving this cost to final consumers.

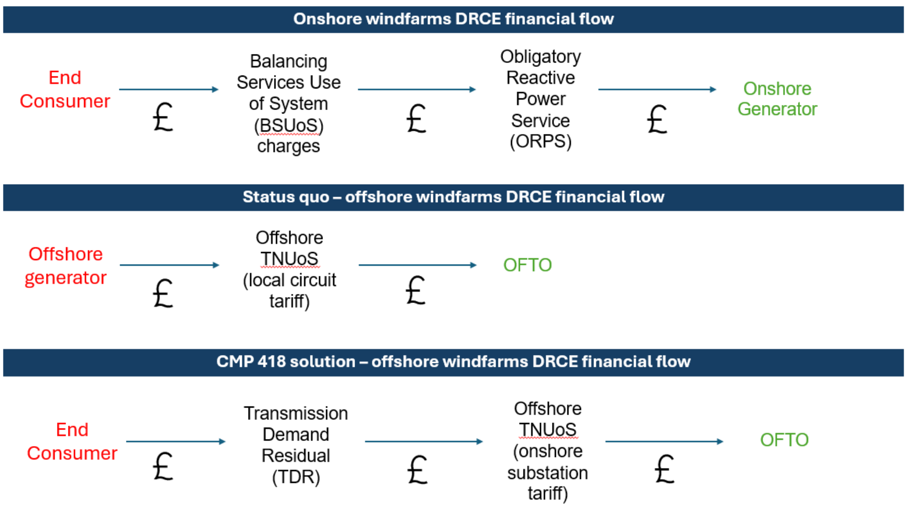
It is expected that removing this cost from generators charges will directly impact consumers' tariff, because, as confirmed by the ESO revenue team, charges for unshared offshore circuits (within which lie DRCE costs in appropriate cases, under baseline) will normally, in the case by case assessment that is made by NESO, be classified, for the purpose of EC838/2010 when calculating the generation adjustment charge, as physical assets required for connection (PARC), and therefore should be excluded when calculating how much revenue is being collected from Generators for the purpose of the EU Cap[7]. This means that reductions in the offshore local circuit charge for relevant generators, if this mod were approved, would normally, result in an increase the Transmission Demand Residual (TDR), rather than the generation adjustment tariff element.[8]

[7] Confirmed by ESO Revenue Team in email to CMP418 WG, available upon request. NESO guidance note on the identification of PARC can be found at download

Figure 5 below illustrates the differences in financial flows for providing dynamic reactive power through DRCE across three scenarios:

- **Onshore Windfarms**: End consumers fund the reactive power service provided by onshore windfarms through BSUoS, which funds the ORPS payments.
- **Current Offshore Windfarms**: At OFTO transaction, the cost of the DRCE falls in the generator's offshore TNUoS local circuit tariff, funded solely by the offshore generator
- **Proposed Solution (CMP418)**: The DRCE cost is moved to the onshore substation tariff, and is expected to be recovered from the Transmission Demand Residual, which is funded by end consumers

Figure 5 DRCE cost financial flows



Estimated Impact:

To assess the cost impact of CMP418, we calculated the portion of costs related to **Dynamic Reactive Compensation Equipment (DRCE)** that is currently recovered from generators through the **offshore local circuit tariff**.

To estimate the impact of **CMP418**, we first determined the number of **Static Var Compensators (SVCs)** required to meet offshore wind deployment targets through 2050. Next, we calculated the portion of the **OFTO** regulated revenue attributable specifically to **DRCE**. This amount represents the cost that will no longer be recovered from generators and is instead expected to be recovered from **final demand**, and it includes both the CAPEX and OPEX element of the SVC cost.

The UK has set an ambitious target of reaching 43-50 GW of offshore wind capacity by 2030[9], and up to 125GW by 2050[10]. As of December 2024, **the UK has approximately 15 GW**[11] **of offshore wind capacity**, which would mean 28 GW is required in the 6 years from 2025 to 2030. To meet the 2030 target, it is necessary to add approximately **4.67 GW per year**, while approximately **4.1 GW additionally capacity is required annually from 2030 onwards to meet the 2050 target**.

The number of DRCEs required to support this new offshore wind capacity has been estimated by considering Static Var Compensators (SVCs) specifically (the most commonly used kind of DRCE, as defined in **Annex 6**).

SVC Cost Estimates

- Each SVC (100 MVar) costs approximately **£17.9 million** and can support **300 MW** of offshore wind capacity[12]. This corresponds to a cost of **£59,667 per MW**.
- This cost estimate is based on mid-range figures from **ETYS 2015** and adjusted for inflation to pre-COVID 2020 prices[13].

Using TRS/FTV Ratio to Calculate SVC Share of OFTO Revenue

To calculate the amount that would need to be recovered from TDR, the TRS/Final Transfer Value (FTV) ratio was used to derive the TRS impact. **The TRS/FTV ratio** is a useful figure to compare the annual amount paid to OFTOs relative to the total offshore transmission CAPEX across Projects, and it **helps us calculate the amount of SVC that falls into the circuit tariff compared to the total TNUoS value paid to the OFTOs**.

1. **TRS (Tender Revenue Stream):**
    - The revenue that an OFTO bidder proposes to collect annually over the operational period.
    - This is determined through a competitive tender process and represents the cost to the system for the OFTO's ownership and operation of the transmission assets.
2. **FTV (Final Transfer Value):**

[9] Clean Power Action Plan announced on 13 December 2024

[10] Climate Change Committee (2020), 'The Sixth Carbon Budget: The UK's path to Net Zero'

[11] Wind Energy Statistic, Renewable UK

[12] ETYS 2015 - Appendix E, 2015

[13] Bank of England Inflation Calculator

- The agreed-upon cost or valuation of the transmission assets being transferred to the OFTO from the developer.
- This value is determined by Ofgem based on the efficient costs incurred during the development and construction of the transmission assets.

3. **The TRS/FTV Ratio:**
   - The TRS/FTV ratio is a useful figure to compare the annual amount paid to OFTOs relative to the total offshore transmission CAPEX across Projects, and it helps us calculate the amount of SVC that falls into the circuit tariff compared to the total TNUoS value paid to the OFTOs.
   - The TRS/FTV ratio measures the relationship between the annual revenue requested by the OFTO (TRS) and the total cost of the assets being transferred (FTV).
   - An analysis of all TRS data available for wind OFTOs between 2011 and 2021 indicates a stabilisation of TRS/FTV ratio at 4% from Tender Round 6 onwards[14].

$$TRS\ Impact\ = \frac{TRS}{FTV} Ratio\ \times (OW\ MW\ \text{pa}\ x\ SVC\ \ \frac{\text{£}}{\text{MW}} cost\ )$$

$$Pre\ 2030\ TRS\ Impact\ \ = 4\%\ \times (4667\ x\ \times 59{,}667)\ \ = \text{£}11.14\text{m per annum}$$

$$Post\ 2030\ TRS\ Impact\ \ = 4\%\ \times (4100\ x\ \times 59{,}667)\ \ = \text{£}9.78\text{m per annum}$$

In the following Table 5:

- the "**Cum. OW (MW)**" column represents the Cumulative Offshore Wind MW expected to be delivered by 2050.
- The "**Cum SVC Cost**" column represents the Cumulative cost of SVC expected to be deployed in relation to the offshore wind MW.
- The "**TRS Impact**" represents the £ cost in the TRS that is specific to the SVC, and it represents the amount that is expected to impact consumers via the TDR.

[14] Aurora Energy Research, 2022 Moray West Report. Available upon request on a confidential basis

Table 5 Estimated TRS impact of CMP418

	Cum. OW (MW)	Cum. SVC Cost (£)	TRS Impact (£)
2025	19,667	1,173,444,444	46,937,778
2026	24,333	1,451,888,889	58,075,556
2027	29,000	1,730,333,333	69,213,333
2028	33,667	2,008,777,778	80,351,111
2029	38,333	2,287,222,222	91,488,889
2030	43,000	2,565,666,667	102,626,667
2031	47,100	2,810,300,000	112,412,000
2032	51,200	3,054,933,333	122,197,333
2033	55,300	3,299,566,667	131,982,667
2034	59,400	3,544,200,000	141,768,000
2035	63,500	3,788,833,333	151,553,333
2036	67,600	4,033,466,667	161,338,667
2037	71,700	4,278,100,000	171,124,000
2038	75,800	4,522,733,333	180,909,333
2039	79,900	4,767,366,667	190,694,667
2040	84,000	5,012,000,000	200,480,000
2041	88,100	5,256,633,333	210,265,333
2042	92,200	5,501,266,667	220,050,667
2043	96,300	5,745,900,000	229,836,000
2044	100,400	5,990,533,333	239,621,333
2045	104,500	6,235,166,667	249,406,667
2046	108,600	6,479,800,000	259,192,000
2047	112,700	6,724,433,333	268,977,333
2048	116,800	6,969,066,667	278,762,667

2049	120,900	7,213,700,000	288,548,000
2050	125,000	7,458,333,333	298,333,333

Additional considerations:

- SVCs were used as costs were readily available and because they are the most used by generators, but STATCOMs are also used as DRCE in offshore wind. Including different types of DRCE in the analysis would be expected to further improve the benefits of this proposed solution. This is because the same cost-saving calculations used for SVCs are applicable to the typically higher costs of other DRCE equipment
- Charges for unshared offshore circuits (within which lie DRCE costs in appropriate cases, under baseline) will normally, in the case by case assessment that is made by NESO, be classified, for the purpose of EC838/2010 when calculating the generation adjustment charge, as physical assets required for connection (PARC), and therefore should be excluded when calculating how much revenue is being collected from Generators for the purpose of the EU Cap. If, in the case-by-case assessment, these assets were not to be considered as physical assets required for connection, it is also expected that the consumer impact would be smaller, as the cost of DRCE would be recovered by all TNUoS users (including generators) instead of only final demand consumers (TDR).

Impact on Wind Farm Development Costs and CfD Levy

Offshore wind projects participate in the **Contracts for Difference (CfD)** scheme, which provides a long-term guarantee on the price per megawatt-hour (MWh) of electricity generated. By moving **DRCE** costs from offshore wind farms to the **Transmission Demand Residual (TDR)**, these projects would save the same amount they currently pay under the existing methodology.

However, these savings would be directly translated into a reduction into CfD bid prices and CfD levy recovered from end users for projects awarded CfD only after the implementation of CMP418.

It is therefore assumed that the gross impact of **£298m by 2050** would be largely netted off by a similar reduction in CfD levy with only a small residual component due to CfD tariffs locked by projects prior to implementation of CMP418. This would create a small residual impact estimated at **£35.8m per annum** according to the methodology and assumptions presented here. In comparison to the **£3,471.8m of TDR revenue** collected from demand users in charging year 2023/2024 this would represent a **1.03% increase**.

Table 6 Estimated CfD levy impact of CMP418

	Cum. OW (MW)	Cum. SVC Cost (£)	TRS Impact (£)	Cum. New OW (MW)	CfD levy reduction (£)	Net Impact (£)
2025	19,667	1,173,444,444	46,937,778	4,667	-11,137,778	35,800,000
2026	24,333	1,451,888,889	58,075,556	9,333	-22,275,556	35,800,000
2027	29,000	1,730,333,333	69,213,333	14,000	-33,413,333	35,800,000
2028	33,667	2,008,777,778	80,351,111	18,667	-44,551,111	35,800,000
2029	38,333	2,287,222,222	91,488,889	23,333	-55,688,889	35,800,000
2030	43,000	2,565,666,667	102,626,667	28,000	-66,826,667	35,800,000
2031	47,100	2,810,300,000	112,412,000	32,100	-76,612,000	35,800,000
2032	51,200	3,054,933,333	122,197,333	36,200	-86,397,333	35,800,000
2033	55,300	3,299,566,667	131,982,667	40,300	-96,182,667	35,800,000
2034	59,400	3,544,200,000	141,768,000	44,400	-105,968,000	35,800,000
2035	63,500	3,788,833,333	151,553,333	48,500	-115,753,333	35,800,000
2036	67,600	4,033,466,667	161,338,667	52,600	-125,538,667	35,800,000
2037	71,700	4,278,100,000	171,124,000	56,700	-135,324,000	35,800,000
2038	75,800	4,522,733,333	180,909,333	60,800	-145,109,333	35,800,000
2039	79,900	4,767,366,667	190,694,667	64,900	-154,894,667	35,800,000
2040	84,000	5,012,000,000	200,480,000	69,000	-164,680,000	35,800,000
2041	88,100	5,256,633,333	210,265,333	73,100	-174,465,333	35,800,000
2042	92,200	5,501,266,667	220,050,667	77,200	-184,250,667	35,800,000
2043	96,300	5,745,900,000	229,836,000	81,300	-194,036,000	35,800,000
2044	100,400	5,990,533,333	239,621,333	85,400	-203,821,333	35,800,000
2045	104,500	6,235,166,667	249,406,667	89,500	-213,606,667	35,800,000
2046	108,600	6,479,800,000	259,192,000	93,600	-223,392,000	35,800,000
2047	112,700	6,724,433,333	268,977,333	97,700	-233,177,333	35,800,000
2048	116,800	6,969,066,667	278,762,667	101,800	-242,962,667	35,800,000
2049	120,900	7,213,700,000	288,548,000	105,900	-252,748,000	35,800,000
2050	125,000	7,458,333,333	298,333,333	110,000	-262,533,333	35,800,000

Conclusion

The introduction of CMP418 is expected to increase the TDR revenue collection by approximately £298 million by 2050. However, this amount is expected to be offset by a reduction of £262m to the CfD levy, leaving a net impact of £35.8m annually, which represents a 1.03% increase to the current base.

Additionally, removing DRCE costs from offshore generators would create a more level playing field between offshore and onshore wind projects, supporting greater competition and encouraging the most cost-effective energy solutions.

Workgroup considerations

The Workgroup convened 6 times to discuss the perceived issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Applicable Objectives.

The Workgroup held their Workgroup Consultation between 2 January 2024 – 22 January 2024 month and received 6 non-confidential responses in total. The full responses and a summary of the responses can be found in **Annex 11.**

Consideration of the proposer's solution

The Proposer gave a presentation to the Workgroup outlining Reactive Compensation Compliance, OFTO Transfer and TNUoS charges, the defect, proposed solution, and initial assessment against the Terms of Reference (**Annex 4**).

The Proposer clarified that Ocean Winds had previously highlighted the commercial discrepancy against offshore Generators with NESO, who had also considered this discrepancy. However, Ocean Wind has not had the resource availability until now to take the issue forward as a modification.

The Workgroup discussed the length of cables and at what length the requirement for a Static Var Compensators (SVCs) (a typical DRCE asset) becomes more prevalent. The Proposer agreed to take an action to Investigate boundaries that could be applied to CMP418. This item was discussed by Workgroup members, and it was agreed that boundaries would not be necessary. This is because the DRCE is required for any offshore windfarm that is 0.5m farther from shore. All offshore windfarms in the UK pipeline will all be located beyond 0.5 miles from shore and thus all will require onshore DRCE.

The Workgroup discussed retrospective application of this modification. The Proposer outlined that initial thinking was to look at future plants. Several Workgroup members noted that the Authority historically are not keen for changes to be applied retrospectively as could lead to opening tariffs from previous years. The ESO Representative commented that retrospective application could take different forms and gave retro charging or inclusion as examples of different approaches. **NESO clarified that to avoid a situation where offshore wind farms before CMP418 are treated differently than offshore wind farms after CMP418 implementation, the proposed change should apply to all offshore wind farms once CMP418 is implemented, but no cost will be recovered from before CMP418**. After implementation, the cost of DRCE will no longer be recovered from offshore TNUoS charges but from TDR instead, and this will not reopen tariffs but only be forward looking for all offshore wind farms. NESO clarified that this is a calculation and would not involve a change to the methodology. This means it would be adjusted and applied from the Implementation date forward and therefore would not involve reopening of tariffs.

The Proposer highlighted that consideration of the Holistic Network Design (HND) was requested by the CUSC panel. The Workgroup discussed this, and it was clarified that if approved, this modification will apply to all radially connected offshore windfarms including those within the HND. The reason is because the defect stems from the allocation of cost of DRCE at OFTO transaction related to the requirements in the Grid Code for any radially connected offshore windfarm.

The Workgroup discussed the fact that the allocation of DRCE costs for offshore TNUoS is not explicitly codified in the CUSC. On Panel's recommendation, the Workgroup discussed whether more complex legal text changes should be suggested as part of the modification. The Workgroup agreed not only that this would be outside of the scope of the modification but above all that the codification of offshore TNUoS cost allocation should not be part of the CUSC. An example was given that CUSC Price controls are not codified – that has been the case so far and ESO agrees. It is not required for the TNUoS cost allocation to be codified for the defect set out in this modification to be addressed. After the send back letter received in September 2024, Ofgem and NESO agreed that the updated legal text would satisfy this requirement.

Cross Code Impacts

The Workgroup discussed a possible cross code impact with the current STC modification CM085.

One Workgroup member raised the point CM085 is ongoing and yet to be determined by the Authority. The Proposer expressed CM085 is codifying what already happens and therefore CMP418 and CM085 support each other.

An ESO Subject Matter Expert (SME) was invited to the Workgroup to present an overview of CM085 and clarify any interaction with CMP418. It was explained to Workgroup members that for the ESO to manage the Transmission System, any reactive power that is available to them may be utilised if it is an economic and efficient choice, and OFTO assets are treated in the same way as onshore assets. The SME confirmed that the Cost Benefit Analysis (CBA) performed as part of CM085 supports this approach.

One Workgroup member expressed concern that CMP418 is predicated on an assumption that DRCE can be used for wider system reasons, and not just for compensating the effects of the OFTO's AC cable, referencing STC Section K. The member suggested a possible consequential change to the STC might be needed as part of CMP418 to clarify this point. The member felt the STC was clear that DRCE is an OFTO asset and not for wider system use, otherwise Section K is being misunderstood by OFTOs. Two members of the Workgroup responded to say it was a technicality and does not affect what happens in real-life. A member felt this issue was being covered by STC change CM085, which was raised by the ESO to clarify that these DRCE assets can be so used.

The Proposer confirmed the modification is not seeking to change this aspect, and Workgroup members concluded no change is required to the STC as part of CMP418. The ESO Representative reiterated this lies at the core of STC change CM085,and if that Workgroup decides to issue a recommendation to amend the wording in STC Section K it will be passed onto the wider ESO team.

Terms of Reference Update

Following a discussion in Workgroup 2, members reviewed and agreed to update the Terms of Reference (ToR) as follows:

- Amend ToR f) by substituting Static Var Compensator (SVC) to **Dynamic Reactive Compensation Equipment (DRCE),** noting this is a Grid Code defined term. The Workgroup evidenced that SVC was an example and subset of DRCE, but DRCE was the range which covered other similar equipment.

- Remove ToR i) as no longer required after the change to ToR f).

It was pointed out by the Proposer accepting the ToR amendments would also result in changes to the CMP418 proposal. The Workgroup discussed the changes and then agreed to the Proposers request to amend the modification title and overview as follows:

- Any reference to SVC within the Original proposal to be replaced with DRCE.

The Workgroup agreed that the scope, principle, and defect of the modification have not been altered because of the update to the ToR accepting SVCs were an example and subset of DRCE, but DRCE was the range which covered other similar equipment. The Proposer clarified that the analysis presented at Workgroup 1 remains the same. The updated final proposal can be found in **Annex 1**.

CUSC November Panel Update

The Workgroup ToR updates and amended modification title were presented to the CUSC Panel on 24 November 2023. Panel members confirmed the change of title and points within the Terms of Reference did not constitute a change in defect. Panel members confirmed the Original proposal and ToR could be updated as requested and for the Workgroup to resume.

Wider Tariff Discussion

The Proposer explained to members a point had been raised by the CUSC Panel on 24 November 2023 regarding the term 'Wider Tariff'. The Panel member had requested the Workgroup to consider if the term should be capitalised in all modification documents as it is a defined term. The Proposer asked the ESO Representative for clarification as there were instances in the CUSC where it appears both capitalised and non-capitalised. The Chair explained to members if the term was capitalised, a definition for Wider Tariff would be required as part of the legal text changes. The ESO Representative confirmed the legal team had reviewed Section 14 and their opinion was wider tariff does not require capitalisation. Workgroup members agreed.

DRCE Ownership Models

The Proposer presented an outline of DRCE ownership models (**Annex 5**) to members describing both the current and proposed technical and commercial treatment of DRCE for onshore and offshore wind farms. The Proposer clarified that the modification is not looking to change asset ownership but moving the OFTO transaction DRCE cost from the local tariff to the wider tariff.

In Workgroup meeting 3, slides on DRCE (**Annex 6**) were presented to the Workgroup covering what reactive power is, why do we want to manage reactive power, reactive power in a typical AC offshore Transmission System and four main examples of DRCE (switched inductors or capacitors, synchronous machines, SVC/STATCOM and inverter/converter).

Confirm Transmission Owner (TO) Payment of Obligatory Reactive Power Service (ORPS)

The Workgroup discussed revenue streams including who receives revenue and for what assets and services. The ESO representative presented a slide (**Annex 8**) referencing an extract from the transmission standard licence condition E15 and verified TO's are paid for Transmission Services as part of their Base Revenue. The ESO representative confirmed they are not paid ORPS. The Proposer emphasised the modification is not asking OFTOs be paid but that offshore Generators are not unreasonably burdened with the cost of DRCE through their local TNUoS tariff.

Impact on Consumers

The Workgroup considered the impact on TNUoS charges if the proposed change was approved by the Authority and if DRCE were moved from the offshore local circuit tariff to the onshore substation tariff and therefore passed through to demand consumers in the demand residual. The Proposer presented **Annex 7** - Impact of Proposed Solution on Consumers.

To calculate the consumer impact of CMP418, the Proposer stated within the presentation that the offshore wind capacity would increase annually and quoted a figure of 3.5GW. A member questioned how many years has been assumed it will continue at that level. The Proposer responded to say there is a target of 40GW of offshore wind by 2030. The same member felt the consultation should also state what comes after that in terms of Government targets out to 2050. Following the discussion, this was updated by the Proposer to a 50GW target by 2030 and 125GW by 2050.

Workgroup members discussed the calculations in detail raising questions around operating costs, overhead factors for maintenance and if this information needs to be separated out in future in terms of the OFTO as the Generator is only given a single number.

The Proposer initially suggested looking at the wider tariff impact of the proposal by using an annuity calculation. This raised doubt among Workgroup members over the correct asset life, rate of return, and maintenance cost required for the calculation. Following Workgroup discussions, the Proposer agreed to simplify the calculation initially proposed. The updated calculation is provided in **Annex 7**.

Consideration of retrospectivity without opening tariffs

The Workgroup discussed how retrospectivity without opening tariffs could be achieved. The Proposer made it clear that the initial proposed solution was not intended to be applied retrospectively. Two Workgroup members felt considering applying retrospectively could delay the modification and there was also some confusion as to the meaning of retrospectivity. NESO clarified that to avoid a situation where offshore wind farms before CMP418 are treated differently than offshore wind farms after CMP418 implementation, the proposed change should apply to all offshore wind farms once CMP418 is implemented, but no DRCE cost will be recovered from before CMP418 implementation (which would entail reopening tariffs). After implementation, the cost of DRCE will no longer be recovered from offshore TNUoS charges but from TDR instead, and this will not reopen tariffs but only be forward looking for all offshore wind farms. NESO clarified that this is a calculation and would not involve a change to the methodology. This means it would be adjusted and applied from the Implementation date forward and therefore would not involve reopening of tariffs.

Other options/Alternatives

No other options or Alternatives were raised as part of the Workgroup consultation or in the Workgroup phase.

Workgroup Consultation Summary

The Workgroup held their Workgroup Consultation between 2 January 2024 – 22 January 2024. The Workgroup consultation received six non-confidential responses in total. The full responses and summary table can be found in **Annex 9**.

A summary of the five non-confidential Workgroup Consultation responses were presented to Workgroup members:

- Three respondents stated the Original Proposal better facilitated objective a)
- Two respondents stated the Original Proposal better facilitated objective b) and e)

- One respondent stated the Original Proposal was negative against objective b)
- Four of the respondents supported the implementation approach.
- In regards to the ongoing DRCE operation and maintenance costs, three respondents felt the value of 1.5% seemed reasonable and equitable to align with onshore TO revenue allowance cost. One respondent felt there was insufficient evidence to understand the origins of the figures or definitions of activities it intends to cover.
- Three respondents agreed the modification should not be applied retrospectively with one stating it avoids reopening tariffs. Another respondent reasoned it should only apply to new installations to prevent understating of costs relating to the Original.

Reasons given in support of the Proposal:

- Better facilitates competition correcting a commercial defect in offshore treatment bringing a level playing field
- Does not seek to open up ORPS to offshore
- Reduces the already substantial TNUoS charge faced by generators

Reasons given against the Proposal:

- Socialising costs means these could be considered transmission assets
- The OFTO would need to seek assurance from the Developer that the DRCE is capable of operating to the expected capabilities from the NESO (this already happens)
- Insufficient evidence provided to understand the origins of the 1.5% figure for DRCE operation and maintenance costs, within the consultation, or the definition of what activities it is intended to cover (relevant to the the calculation of impacts on TDR, which is only an estimation)

The Chair asked if members would like to add anything to the summary. No additions were suggested. One Workgroup member agreed this was a fair synopsis of the responses received.

A statement made in a response supportive of the Proposal was highlighted to the Workgroup by the Chair:

'Dynamic Reactive Category should capture all types of Dynamic Reactive Devices including STATCOM.'

The Chair suggested the respondent was referring to an earlier version of the Proposal and this issue had already been addressed when the Proposal was updated. Workgroup members agreed changing the CMP418 proposed legal text detail from Static Var Compensators (SVC) to Dynamic Reactive Compensation Equipment

(DRCE) already captured STATCOM as suggested by the respondent.

Review Workgroup Consultation Responses

One respondent had raised a number of points unsupportive of the solution. The Proposer prepared responses to these arguments and shared these with the Workgroup.

The first argument was that the current charging arrangement reflects an historical expectation that generators are obliged to provide reactive services and compliance with Grid Code (GC). The Proposer explained generators are obligated to provide reactive services in compliance with the GC and confirmed this will not change as a result of CMP418. The Proposer also pointed out it had been explained in the consultation that onshore DRCE will be required to ensure GC compliance for any offshore wind farms farther than 0.5 miles from shore. This proposal will not change the obligations under the GC for offshore wind generators or OFTOs, the change is merely commercial in nature to reflect fairness against the onshore regime.

The second argument, made by the respondent, was that by changing the charging arrangement so that the cost is moved to wider tariff (ultimately TDR) rather than directed to the party that triggers them means these could be considered transmission assets rather than operated for the benefit of the windfarm. The Proposer clarified that given that in the context of an onshore windfarm, the DRCE when installed is also operated for the benefit of the windfarm and retained as Generation Asset, while continuing to be compensated through ORPS, DRCE in the context of offshore will continue to be considered a Generation Asset. The Proposer confirmed the proposed solution will not change the existing arrangements, and ownership of DRCE will remain with the OFTO, post the OFTO transaction. If the asset were not considered part of the transmission assets, the OFTO would not be remunerated for its provision of reactive services via the Base Revenue, as it currently is. Similarly, if the asset was considered a generator asset, then the offshore generator would be able to access the ORPS, which they are not. Workgroup members agreed with the Proposer's assessment. The Chair felt details of the proposal may have been missed by the respondent as they are confined within the Annexes.

Concerns were also raised by the same respondent surrounding the interaction of CMP418 and CM085. The Proposer recalled the NESO Subject Matter Expert (SME) had found no interaction between the modifications. The SME also confirmed CM085 requires no changes to the current DRCE set up or the Grid Code requirements. A Workgroup member perceived this had already been made clear in the consultation and felt the Workgroup response should be that CM085 is relating to a separate issue and that CMP418 does not impact on CM085. Workgroup members agreed with this statement.

Consumer Impact

The Proposer requested support to understand what the consumer impact of CMP418 will be and to confirm the interaction with the connection exclusion and the demand residual. NESO Representative agreed to consult with NESO revenue team to provide information on connection exclusion charges, the end consumer financial impact of DRCE being included within this and associated change to NESO cost recovery. The Representative informed members this will not necessarily be analysed.

The Chair inquired if any members could share any insight on consumer impact and interaction with the conclusion exclusion to support the proposal. One Workgroup member offered to also answer the question posed by the Proposer but requested NESO to confirm this is aligned with thoughts from the charging team. NESO revenue team confirmed the understanding that local circuit tariffs are part of the Connection Exclusion and therefore the change proposed under CMP418 would mean moving the recovery of DRCE costs from offshore generators to the TDR. Please see estimated calculations of CMP418's impact on TDR in **Annex 7.**

Legal text

The Section 14 legal text for this modification can be found in **Annex 12**, and consists of minor changes to clauses 14.25.80 and 14.15.137 of Section 14 of the Charging Statement to make clear that DRCE will be excluded from the offshore circuit revenue calculation.

The addition to this clause is highlighted in red in the draft legal text below.

CUSC Section 14 of the CUSC

Offshore Circuit Expansion Factors

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by OFTOs for each offshore circuit. Offshore expansion factors are OFTO and circuit specific. Each OFTO will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment (excluding Dynamic Reactive Compensation Equipment), harmonic filtering equipment, asset spares and HVDC converter stations.

The Residual Tariff

14.15.137 As a result of the factors above, in order to ensure adequate recovery of total Transmission Owner revenue, a set of non-locational Transmission Demand Residual Tariffs are calculated, which include infrastructure substation asset costs and the cost of Dynamic Reactive Compensation Equipment. These tariffs are billed alongside the initial transport tariffs for demand only so that the total revenue recovery is achieved. The total amount of revenue to be recovered through Transmission Demand Residual Tariffs is defined as the Transmission Demand Residual.

Also in **Annex 12** is the draft legal text for Section 11 of the CUSC (Definitions) which will be raised via another modification and is included purely for reference and not for consultation.

What is the impact of this change?

Proposer's assessment against Code Objectives

Proposer's assessment against CUSC Charging Objectives	
Relevant Objective	**Identified impact**
(a) 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;	**Positive** Lower charges would reduce financial barriers for future offshore wind developers, potentially enabling offshore wind to better compete with other sources of generation. It mitigates the revenue opportunity that onshore Generators can receive through providing voltage control service that is unavailable to offshore Generators, even though both parties are exposed to the cost and installation of DRCE. Ultimately the change proposed creates a parity of approach with regards to reactive power compensation costs between onshore and offshore generators.
(b) 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	**Neutral**

which are made under and 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);	
(c) That, so far as is consistent with sub-paragraphs (a) and (b), 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*;	**Neutral** CUSC would neither be more nor less adaptable to developments in transmission licensees' transmission businesses
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Neutral** No impact
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Positive** A more equitable allocation of costs that takes better account of OFTOs and offshore Generators mandatory requirements under the Grid Code improves the overall cost-reflectivity of the system charging methodology. It ensures that OFTOs, onshore, and offshore Generators treatment is aligned in respect of mandatory reactive power requirements.
* See Electricity System Operator Licence **The Electricity Regulation referred to in objective (d) 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 has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.	

Proposer's assessment of the impact of the modification on the stakeholder / consumer benefit categories	
Stakeholder / consumer benefit categories	**Identified impact**
Improved safety and reliability of the system	**Neutral**

	No impact on safety and reliability, as the technical details of the equipment do not change. The proposed modification is to the charging methodology only.
Lower bills than would otherwise be the case	**Positive** DRCE costs will no longer be part of the offshore local circuit tariff borne by the generator. Since offshore wind projects participate in the Contracts for Difference (CfD) scheme, which provides a long-term guarantee on price per MWh, these savings have the potential to reduce the CfD price by an amount equal to the annual saving. The introduction of CMP418 is expected to increase the TDR revenue collection by approximately £298 million by 2050. However, this amount is expected to be offset by a reduction of £262m to the CfD levy, leaving a net impact of £35.8m annually, which represents a 1.03% increase to the current base.
Benefits for society as a whole	**Positive** Lower costs means that offshore wind farms are likely to be more competitive overall, and therefore more likely to be developed and connect. This can contribute towards the UK meeting its 50GW offshore wind by 2030.
Reduced environmental damage	**Positive** Lower costs mean that offshore wind farms are likely to be more competitive overall, hence potentially displacing more fossil fuel generation more quickly. This reduces the carbon in the grid, enabling de-carbonisation of the electricity system to happen more quickly.
Improved quality of service	**Positive** Less cost for offshore wind farms is likely to lead to an increase in the number of projects that will be undertaken in GB, thus generating more jobs to facilitate these projects.

Workgroup Vote

The Workgroup met on 08 February 2024 to carry out their Workgroup Vote[15]. The full Workgroup vote can be found in **Annex 13**. The table below provides a summary of the Workgroup members view on the best option to implement this change.
The Applicable CUSC (charging) Objectives were:

a) 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.
b) 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 accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection).
c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.
d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and
e) To promote efficiency in the implementation and administration of the system charging methodology

*The Electricity Regulation referred to in objective (d) 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 has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.

The Workgroup concluded unanimously that the Original better facilitated the Applicable Objectives than the Baseline.

Option	Number of voters that voted this option as better than the Baseline
Original	6

First Code Administrator Consultation Summary

The Code Administrator Consultation was issued on the 26 February 2024 closed on 21 March 2024 and received three non-confidential responses. The full responses can be found in **Annex 11.**

[15] Applicable Objectives were correct at the time of the Workgroup Vote

Code Administrator Consultation summary	
Question	
Do you believe that the CMP418 better facilitates the Applicable CUSC Objectives?	Two respondents stated the Original better facilitates CUSC objectives than the Baseline. Both of these respondents stated the Original Proposal better facilitates objectives a and b.
Do you support the proposed implementation approach?	Two out of the three respondents support the implementation approach.
Do you have any other comments?	Two out of three respondents preferred option was the Original. The two respondents supportive of the Original proposal gave the following reasons: Corrects a commercial defect in the treatment of offshore and onshore wind farms arising from the current charging methodology and therefore better facilitates competition. • Will support future offshore wind projects and helps to meet the 2030 offshore wind target of 50GW. • Prevents offshore generators being adversely impacted from the inclusion of the DRCE costs within their local circuit tariffs, a tariff which is paid for over the lifetime of the asset. • Costs incurred by transmission licensees on shared transmission infrastructure is typically socialised across Users and moving the DRCE charge from the local circuit tariff to the onshore s/s tariff which is shared across all users thereby correcting this defect. The respondent not supportive of the Original proposal gave the following reasons: • Artificially shifts costs from generation to final demand and will differentiate between generators (including existing versus future offshore generators). This creates distortions through costs not being appropriately allocated. • No benefit to consumers is demonstrated and no useful analysis has been provided of

	the consumer impact via increases in the Transmission Demand Residual (TDR). • Cost-reflectivity will be reduced as the specific cost per project is passed on via the TDR. • CfD bids already incorporate the cost and are the relevant, existing mechanism to recover it.
Legal text issues raised in the consultation	
No legal text issues were raised by the respondents.	

Panel Recommendation

The Panel met on the 26 April 2024 to carry out their recommendation vote.

They assessed whether a change should be made to the CUSC by assessing the proposed change and any alternatives against the Applicable Objectives and The Panel has recommended by majority that the Proposer's solution is implemented, see Annex 14 for the full vote details.

Authority Decision to send – back

On 30 September 2024, Ofgem sent back the CMP418 Final Modification Report for further work and directed Panel to revise and resubmit the CMP418 Final Modification Report (**Annex 15**).

The Authority stated that there were 4 deficient areas which meant they were unable to form an opinion:

a. The FMR use of interchangeable terminology and or definitions made it unclear as to what basis the cost allocation comparison was being made
b. The FMR fails to provide a clear and detailed description of the current arrangements for the recovery of DRCE costs, for either onshore or offshore generators
c. The FMR is unclear as to what the actual intended tariff for cost allocation would be.
d. The FMR presents significant ambiguity in its use of terminology and definitions regarding the classification and cost recovery treatment of shunt reactors and DRCE.

Workgroup Discussions following Authority decision

The Proposer, NESO, and the Authority met on 14 October 2024 to ensure there was clarity on the requirements ahead of resubmitting the FMR as the Proposer felt that most of the issues highlighted in the Send Back Letter could be resolved with tactical restructuring of the FMR as the Workgroup had already gathered the information required to meet the deficiencies.

The Panel on 25 October 2024 agreed that the Proposer work with the Code Administrator and NESO to ensure that the FMR is rewritten and clarified, followed by the Workgroup verifying that the updates reflect previous discussions before a second Code Administrator Consultation is issued to Industry.

The below table outlines how the deficiencies have been addressed in this document:

Ofgem Send Back Letter	Response
Provide clarity in terms of the assets that are being compared and a clear and detailed explanation of the treatment of those assets between onshore and offshore generators, with respect to recovery of DRCE costs. Ensure that this demonstrates the need for the proposed changes. This should also include specific examples and a clear comparison of the onshore and offshore charging methodologies.	Additional narrative in the Why Change? section. Generic example of offshore local circuit tariff added into what is the solution section and more details in Annex 7 regarding the cost recovery pre and post CMP418.
The FMR must include a detailed explanation of the operational principles guiding the cost allocation for DRCE. It should explicitly compare these principles between onshore and offshore regimes, providing a robust rationale for why the proposed changes are necessary and justified.	Covered in section 3. Technical background.
The revised FMR and legal text must clearly articulate the specific changes to the cost recovery mechanism for DRCE. In particular, it should be clear as to which tariff the DRCE costs are being moved to (e.g. the demand residual). Inconsistent use of terminology	Covered in the proposed solution section. An additional modification to define the DRCE in the CUSC is in the process of being raised by the proposer.

should be avoided with any proposed changes being consistent with established CUSC terms to prevent any further ambiguity.	
If it is the Proposer's intent that shunt reactors should be included in the offshore local tariff, then the FMR and legal text should clearly state this intent and include explicit definitions of both DRCE and shunt reactors. The FMR must also clearly articulate the rationale for the different treatment of DRCE and shunt reactors, justifying why shunt reactors should remain in the offshore local circuit tariff while DRCE costs are moved to the wider TNUoS via the TDR. To support this distinction, the FMR should provide detailed explanations of their respective roles, functions, and benefits. Additionally, it is important to clarify whether the existing definition of DRCE in the System Operator Transmission Owner Code (STC) and Grid Code (GC) would include shunt reactors, as this could have implications for the legal text and the overall implementation of the Proposal.	Clarified in proposed solution section. Clarified in technical background section. Grid code definition added. STC does not define the term. A further modification is being raised by the Proposer in parallel to ensure the definition of DRCE is added to Section 11 of the CUSC.
The legal text provided in the FMR lacks clarity regarding the exclusion of DRCE costs from offshore local circuit tariffs. There is ambiguity around the treatment and cost allocation of DRCE, particularly concerning whether these costs should be excluded from offshore local tariffs when DRCE is located at the Onshore Interface Point. Additionally, the distinction between DRCE and other reactive power equipment, such as shunt reactors, is not well-defined within the legal text. This lack of specificity creates confusion about the cost recovery process and the roles of different assets.	Added some more explanation into the legal text section from Annex 3. This new version of legal text has been reviewed with NESO. An additional modification will be raised to add a definition of DRCE in CUSC Section 11 as per the definition in the Grid Code (Annex 12).

we have reviewed the quantitative analysis presented in Annex 7 of the FMR. Our initial view is that this analysis does not provide a comprehensive or balanced view of the impacts of CMP418, particularly regarding the proposed reallocation of DRCE costs. The analysis appears too high-level, focusing primarily on changes to the Tender Revenue Stream ("TRS") without adequately exploring the broader impacts any change to cost reallocation would have on the TDR tariffs and end consumers. We would encourage the Workgroup to consider a more detailed and holistic assessment to ensure that the Proposal's impacts are fully understood and appropriately evaluated.	We clarified the calculation to explain why looking at the TRS impact is a good solution to calculate the consumer impact. Anything that is removed from generator's offshore TNUoS charge and from OFTO's TRS related to DRCE is the amount that will be now be recovered from to the Transmission Demand Residual instead. We also updated the calculation on CfD impact to show that there will be a net impact of £35.8m annually on consumers, while the rest of the costs to be recovered from consumers under CMP418 are expected to be net off by a reduction in CfD levy.
Furthermore, we consider that the analysis and arguments presented with respect to the Proposal resulting in reduced Contracts for Difference ("CfD") bids and a net benefit for consumers over the long term, does not provide a well-rounded view of the Proposal. The removal of DRCE costs from generators via CMP418 would result in a windfall gain for those generators who already have contracts in place. Therefore, by not quantifying the value of this windfall gain in the analysis, we consider that it does not provide a balanced assessment. We would encourage the Workgroup to consider providing further analysis on the potential impacts the Proposal will have on consumers tariffs.	The introduction of CMP418 is expected to increase the Transmission Demand Residual (TDR) revenue collection by approximately £298 million by 2050. However this amount is expected to be offset by a reduction of £262m to the CfD levy, leaving a net impact of £35.8m annually, which represents a 1.03% increase to the current base.
Connection Charges are distinct of Local Circuit and/or Local Substation Tariffs (collectively herein, "Local Charges"), are calculated under different methodologies, and relate to different assets: Connection Charges are levied in respect of the assets described at 14.2.4 - 14.2.9 of CUSC, whereas Local Charges apply per 14.15.32 – 14.15.36 of CUSC. In summary, the CUSC is clear that the assets used to connect a generator's equipment to the 'first' transmission substation on the system attract Connection Charges, and that Local Charges apply to the assets between that first substation and the Main Integrated Transmission System ("MITS"), unless that first substation is part of	This point has been rephrased. As confirmed by the ESO revenue team again, charges for unshared offshore circuits (within which lie DRCE costs in appropriate cases, under baseline) will normally, in the case by case assessment that is made by NESO, be classified, for the purpose of EC838/2010 when calculating the generation adjustment charge, as physical assets required for connection (PARC), and therefore should be excluded when calculating how much revenue is being collected from Generators for the purpose of the EU Cap

the MITS in which case no Local Charges are payable.	

When will this change take place?

Implementation date

1 April 2025

Date decision required by

ASAP

Implementation approach

No systems or processes will need to change as a result of this Proposal.

Interactions

☐Grid Code	☐BSC	☐STC	☐SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[16]	☐Other modifications	☐Other

It is not foreseen that this modification interacts with other codes, industry documents, modifications, or industry projects.

How to respond

Code Administrator Consultation questions

- Please provide your assessment for the proposed solution against the Applicable Objectives?
- Do you believe that the amendments have met the deficiencies of the Send Back letter?
- Do you support the proposed implementation approach?
- Do you have any other comments?

Views are invited on the proposals outlined in this consultation, which should be received by 5pm on **19 February 2025**.

Please send your response to cusc.team@nationalenergyso.com using the response pro-forma which can be found on the modification page.

If you wish to submit a confidential response, mark the relevant box on your consultation proforma. Confidential responses will be disclosed to the Authority in full

[16] If the modification has an impact on Article 18 T&Cs, it will need to follow the process set out in Article 18 of the Electricity Balancing Regulation (EBR – EU Regulation 2017/2195) – the main aspect of this is that the modification will need to be consulted on for 1 month in the Code Administrator Consultation phase. N.B. This will also satisfy the requirements of the NCER process.

but, unless agreed otherwise, will not be shared with the Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Acronyms, key terms and reference material

Acronym / key term	Meaning
BSC	Balancing and Settlement Code
CBA	Cost Benefit Analysis
CfD	Contract for Difference
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
DRCE	Dynamic Reactive Compensation Equipment
EBR	Electricity Balancing Regulation
NESO	National Electricity System Operator
FTV	Final Transfer Value
HND	Holistic Network Design
HVDC	High Voltage Direct Current
GEP	Generator Entry Point
NETS	National Electricity Transmission System
OEC	Offshore Export Cable
OFTO	Offshore Transmission Owner
ORPS	Obligatory Reactive Power Service
POC	Point of Connection
SME	Subject Matter Expert
STC	System Operator Transmission Owner Code
SQSS	Security and Quality of Supply Standards
SVC	Static Var Compensator
TCMF	Transmission Charging Methodology Forum
TNUoS	Transmission Network Use of System Charges
TO	Transmission Owner
TRS	Tender Revenue Stream
WTG	Wind Turbine Generators

Annexes

Annex	Information
Annex 1	Proposal form
Annex 2	Terms of reference
Annex 3	Consultant report Operation of DRCE in Power Systems
Annex 4	OW presentation Introduction to the Proposed Solution
Annex 5	Onshore vs Offshore DRCE Ownership Models

Annex 6	DRCE Definition
Annex 7	Impact of Proposed Solution on Consumers
Annex 8	TO Payment of reactive compensation requirement confirmation
Annex 9	Workgroup Consultation Responses and Summary Table
Annex 10	Attendance and Action Log
Annex 11	Code Administrator Consultation Responses
Annex 12	Legal Text Section 14
Annex 13	Workgroup Vote
Annex 14	First Panel Recommendation Vote
Annex 15	CMP418 Send Back Letter