Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators

Consultation

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Overview:

Two Connection and Use of System Code (CUSC) modifications have been raised to address reform of certain so-called "embedded benefits", which include payments that some generators can receive for helping suppliers to avoid transmission demand residual charges. This consultation considers the impact of the options presented to Ofgem for decision and requests stakeholders' views on our minded to decision.

Following the consultation and our consideration of responses, we plan to publish a final decision in May of this year.

[1]This document was re-issued on 15 March 2017 to incorporate minor corrections made since the original publication. These are listed on the document's landing page: https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-consultation-cmp264-and-cmp265-minded-decision-and-draft-impact-assessment

Context

Our changing energy system means that there is a continuing need to consider all network charging arrangements periodically and ensure that they best facilitate the competitive market needed to deliver the best outcome for consumers.

This consultation considers the impact of all options presented to Ofgem[2] for decision and requests stakeholders' views on our minded to decision.

Associated documents

Ofgem Open Letter on Charging Arrangements for Embedded Generation, July 2016, https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_-_charging_arrangments_for_embedded_generation.pdf

Responses to Ofgem's July open letter on Charging Arrangements for Embedded Generation, December 2016
https://www.ofgem.gov.uk/publications-and-updates/responses-our-july-open-letter-charging-arrangements-embedded-generation

Ofgem Update Letter - Charging Arrangements for Embedded Generation, December 2016
https://www.ofgem.gov.uk/system/files/docs/2016/12/update_letter_-_charging_arrangements_for_embedded_generation.pdf

National Grid Review of the Embedded (Distributed) Generation Benefit Arising from Transmission Charges, December 2013
http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=29996

National Grid Review of the Embedded (Distributed) Generation Benefit Arising from Transmission Charges – Conclusion Letter, April 2014
http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=32765

Final CUSC Modification Report CMP264/265/269, November 2016
http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937775

[2] Ofgem is the Office of Gas and Electricity Markets. Our governing body is the Gas and Electricity Markets Authority and is referred to variously as GEMA or the Authority. We use "the Authority", "Ofgem" and "we" interchangeably in this document. More information can be found here https://www.ofgem.gov.uk/publications-and-updates/powers-and-duties-gema

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Executive Summary

Background

Over the past year, we have highlighted concerns about the electricity transmission network charging arrangements for sub-100MW ('smaller') Embedded Generators (EGs), including the exemptions and payments collectively referred to as 'Embedded Benefits'. We have previously indicated that the ability of a supplier to use smaller EG to reduce transmission use of system charges, and for smaller EG to be paid to help others avoid them, may be creating a distortion. We indicated in July and again in December last year that one element – specifically the TNUoS Demand Residual (TDR) – appeared to be a significant cause for concern.

TDR charges are top-up charges which ensure that the appropriate amount of allowed revenue is collected from demand users once locational, cost reflective, charges have been levied. The amount of revenue which needs to be recovered from TDR charges does not change when individuals use the system differently. Any TDR charges avoided by the use of smaller EG have to be recovered from other users of the network, leading to higher charges for everyone else. The payments by suppliers to smaller EG also add to consumer costs.

Two modification proposals to the relevant industry code have been raised through the open industry process (CMP264 and CMP265) to address these distortions, along with 23 workgroup alternatives (WACMs) produced during the industry self-governance workgroup process. The proposals include a range of values which could replace the current TDR payments to smaller EG, and various implementation options, including normal implementation, phasing the path to the new level over several years or 'grandfathering'[3] the current level of payments for a subset of smaller EG with 2014 and 2015 CM contracts and Contracts for Difference (CfD) for 15 years. We are required to assess which of these proposals better, and then ultimately best, facilitates the CUSC objectives and furthers our statutory duties.

Assessment and findings

We consider that the current methodology results in a transfer (and therefore additional cost) of around £350m/year from consumers to smaller EG. Without reform, this figure is forecast to rise to £650m/year by 2020/21. Further, there is evidence that TDR payments to smaller EG are distorting other markets, including the Capacity Market (CM), wholesale and ancillary services markets.

We have undertaken a detailed assessment of all 25 proposals put to us. Our assessment takes into account the responses to our July 2016 open letter, the views of the CUSC Panel, the consultation responses from the workgroup process and the Final Modification Report.

[3] A number of proposals allow specific subsets of existing generators to continue to receive payments at the current level, protecting them from the impact of any changes. This is described in more detail in chapter 3.

Our assessment also takes into consideration the quantitative assessment from the LCP/Frontier modelling that we commissioned. We found that several proposals better facilitated the CUSC objectives – in particular on competition and cost reflectivity grounds.

Competition is best facilitated by non-discriminatory arrangements that lead to the most efficient businesses succeeding, ultimately driving down costs for consumers. Regarding cost reflectivity, users who benefit from the network should face charges that broadly reflect the costs that they impose, as when faced with the true cost of their behaviour, they are more likely to make efficient choices. Where a payment is made it should reflect the savings that users bring to the system.

The evidence we are consulting on indicates that smaller EG can offset the need for reinforcement which arises from an increase of demand at each Grid Supply Point (GSP) – the point where the transmission and distribution networks meet. We therefore consider payments that reflect these savings to be cost reflective.

We do not think that the justification for exposing smaller EG to the TNUoS generation residual, or indeed for payments above this level, in the form set out by the proposals has been made. We think that the current TNUoS generation residual "embedded benefit" would be better considered through the proposed Targeted Charging Review (TCR)[4].

We have considered the case for grandfathering of these arrangements for a specific sub-set of smaller EG plant and consider that the arguments against this are stronger than the case for. In particular, there are potential negative impacts of grandfathering on competition, when compared to similar options without grandfathering. Grandfathering would also prevent further changes to the charging arrangements for those network users for 15 years, reducing the ability to make future changes to these arrangements for this subset of users, and would require additional administrative efforts. We do not consider that a lack of grandfathering would result in unfairness to smaller EG since prudent investors know that charging arrangements are subject to change through the code governance process.

We have carefully considered the case for transitional arrangements and consider there is a case for the gradual, phased introduction of the new arrangements over three years from 2018 to 2020, due to the scale of the changes and the potential impact on dispatch behaviour. Allowing a gradual introduction of this significant change will provide time for generators to adapt their despatch and business models, which will minimise short term security of supply pressures. During this transitional period, we are proposing to undertake the TCR which will consider the other benefits received by smaller EG alongside the wider question of how residual/cost recovery charges should be levied and other matters. We consider that further delay to changes to the arrangements would not be in the best interest of consumers and would increase uncertainty and risk for investors.

[4] In our July and December 2016 open letters we indicated that we thought a targeted charging review should consider a range of charging issues and we will be consulting on this shortly

Conclusion

Our minded to decision is to direct that WACM4 be made. The level of TDR payments to smaller EG should be reduced to the avoided GSP costs, and we believe a phased approach would be justifiable. We think that this represents a robust, evidence based solution that best facilitates the CUSC objectives and our statutory duties, and offers the best balance of benefits and costs to consumers and investors. It will allow industry time to adjust to the proposed changes and allow time for affected generators to adjust their despatch and business models, which will minimise short term security of supply pressures.

We welcome views on this consultation and will consider all responses received up to 9am on 18 April 2017.

1. Introduction

Chapter Summary

This chapter provides a brief introduction to Ofgem's duties as an economic regulator, why we are publishing a draft impact assessment, and what we want to get from publishing this consultation on our minded to decision.

Purpose of this consultation

1.1. This consultation document incorporates our draft impact assessment, which assesses the effect that the code modification proposals, submitted to us for decision, will have on consumers, industry participants, and any social or environmental impacts. The document also contains our proposed ("minded to") decision on the code modifications. We are seeking views and further evidence on both the draft impact assessment and the minded to decision as part of our decision-making process.

1.2. In this instance, we have been asked to make a decision on proposals to change the Connection and Use of System Code (CUSC). The proposals, discussed later in this document, have been through an industry workgroup process and consultation and now require a decision from us. Due to the impact that the changes may have, we have decided to publish a minded to decision and draft impact assessment, which sets out our current preferred choice, and to seek views on that minded to decision.

1.3. We will take responses to the consultation on this draft impact assessment into account when making our final decision, as well as the views from the industry consultations, CUSC Panel view, and the views of the workgroup in the Final Modification Report (FMR). We will then make a final decision based on the CUSC objectives and our statutory duties.

1.4. This is a draft impact assessment produced under section 5A of the Utilities Act 2000. Please note the quantitative modelling included in this draft impact assessment is for the purposes of this decision only, and does not constitute an official Ofgem forecast of future network charges, energy costs, CM clearing prices or any other element.

Ofgem's duties

1.5. Ofgem's principal objective is to protect the interests of existing and future energy consumers. In accordance with our statutory duties, we work to promote value for money, security of supply and sustainability for consumers. We do this through the supervision and development of markets, regulation and the delivery of government schemes.

1.6. The interests of consumers are their interests as a whole, including their interests in the reduction of greenhouse gases, the security of supply of gas and electricity, and the fulfilment of the objectives of the Third Package.[5] In addition, our general duties require us to have regard to the needs of vulnerable consumers and the principles of Better Regulation, as well as the need to contribute to sustainable development (among other things).

1.7. When we make a decision, we must do so in a way that best protects the interests of existing and future consumers. This includes balancing the benefit of any action we take against the cost that may be imposed as a result of those requirements. Impact assessments play an important role in helping us to achieve our statutory duties.

[5] These are the objectives set out in Article 40(a) to (h) of the Gas Directive and Article 36(a) to (h) of the Electricity Directive.

2. Background

Chapter Summary

This chapter provides a background to transmission charging and the "embedded benefits". Later in the chapter we explain why we are required to make a decision on the two CUSC modifications and their 23 alternatives, and set out the results of the CUSC industry workgroup.

Question 1: Do you agree with our problem definition and that the Transmission Network Use of System (TNUoS) Demand Residual (TDR) payments to sub-100MW Embedded Generation ("smaller EG") are distorting dispatch, wholesale price, the capacity market (CM) and that they pose an increased cost to consumers?
Question 2: Do you agree that rising TDR payments to smaller EG is a problem which needs to be addressed?

Transmission Charging

2.1. Transmission Network Use of System (TNUoS) charges recover the cost of building and maintaining the transmission system.[6] They are levied partly on generation and partly on demand. Transmission charges for generation only currently apply to generators directly connected to the transmission network or to generators connected to the distribution network[7] that are above 100MW in capacity. Generation which is below 100MW on the distribution network ("smaller EG[8]") does not pay transmission charges but is instead treated as 'negative demand'.

'Embedded Benefits'

2.2. Transmission charging for demand is calculated based on a user's net demand at particular times known as triad periods.[9] Currently this is based on net demand in a Grid Supply Point (GSP) group – net demand is the gross or total customer demand on the distribution network, less any generation output from smaller EG on the distribution network within each GSP group. As such, generation connected to the distribution network that is below 100MW (smaller EG) is treated not as generation, but as 'negative demand'.[10] This means that smaller EG are often paid by suppliers to generate at triad (and sometimes

[6] An introduction to the transmission charging regime is available in appendix 1.
7 Referred to as distribution-connected generation, distributed generation or embedded generation.
[8] Only sub-100MW "smaller EG" do not pay transmission charges. Other embedded generation is treated like transmission-connected demand. For the purposes of this document we use the term smaller EG to refer to sub-100MW generation on distribution system. Generation of this type might include onshore windfarms, diesel or gas reciprocating generation or small CHP units.
[9] The three half hour periods of highest demand between November-February, separated by at least 10 days.
[10] It therefore faces the inverse of the demand transmission charges.

directly by National Grid), to reduce the suppliers net demand off the transmission system, and therefore reduce their TNUoS charges. The cost of these payments from suppliers (or negative charges from National Grid) to smaller EG is recovered from consumers (explained further in 'problem definition').

2.3. 'Embedded benefits' are the payments which smaller EG get, and the charges they do not have to pay, compared to larger (over 100MW) EG on the distribution system and transmission connected generators. Smaller EG can realise these benefits due to their location on the distribution system and their size.

2.4. 'Embedded benefits' come in the form of both payments that smaller EG receive for helping suppliers[11] to avoid transmission charges (or payments they receive directly from National Grid), and also avoided transmission generation charges that these generators do not pay.

2.5. The table below sets out the main embedded benefits relating to transmission charging[12]. We have not considered Residual Cashflow Reallocation Cashflow (RCDC) and Areas of Assistance (AAHDC) in any detail as they are low in value and unlikely to be causing major distortions. For this draft impact assessment, we will be focusing on the TNUoS demand residual (TDR) payment, as the proposals that have been put forward to us mainly make changes to the level of this payment. We have also not considered any other payments made to embedded generators from distribution use of system charging arrangements. For an explanation of the components of the TNUoS charge, please see appendix 1.

[11] During the CMP264/5 workgroups, National Grid estimated a 7.5GW of smaller EG runs during winter peak periods. In addition, the more EG that is used to offset charges, the smaller the demand charging base, which leads to higher user charges.

[12] It also covers Balancing Services Use of System charges (BSUoS) which pays for the balancing of the energy flows on the transmission system by National Grid in their role as System Operator.

Table 1 - List of embedded benefits related to transmission charging

Embedded benefit element	What is it?	Current value
TNUoS demand residual (TDR) payments	**This is the largest embedded benefit. Smaller EG can receive these payments from suppliers or Grid.**	**c. £45/kW**
TNUoS generation residual (TGR)	Smaller EG currently does not pay the TNUoS generation residual.	c£0.5/kW
TNUoS locational charges (demand and generation)	Smaller EG that generates at triad (mainly non intermittent EG) is treated as negative demand and hence face the inverse of the demand locational signal. This is roughly equivalent to facing the generation locational signal. The differences between the two signals are: • the difference in charging bases, with triad for demand vs TEC for generation • different treatment of intermittent/non-intermittent • different zonal differentiation (27 generation zones vs 14 GSP Groups).	Demand locational charge varies by region and is £-5.09/kW to £6.54/kW Generation locational signal varies by region and technology and is £-6.91/kW to £19.14/kW
BSUoS demand charge payments	The BSUoS demand charge is based on a supplier's net consumption at the GSP groups, so smaller EG can offset demand and receive payments for reducing the BSUoS bill for suppliers.	c£2/MWh[13] Equivalent to c£4/kW-c£17/kW dependent on load factor[14]
BSUoS generation charge	Smaller EG currently does not pay the BSUoS generation charge	c£2/MWh Equivalent to c£4/kW-c£17/kW dependent on load factor

Definition of the issue

Our open letters

2.6. In July 2016, after the code modification proposals had been made, we published an open letter[15], discussing the issue of escalating TDR payments to smaller EG, setting out our (then) views and asking for comments and evidence from industry. In December, we published an update letter[16], setting out the key developments since our July open letter, and providing an update on our views to market participants, particularly those bidding into the CM T-4 and early capacity auctions in late 2016/early 2017.

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[13] BSUoS charges vary between £-0.23-£47.78/MWh depending on the settlement period. £2.40/MWh is an average across the 2016-/17 charging period.
[14] Ranges assumes a load factor of 20% – 80%
[15] https://www.ofgem.gov.uk/publications-and-updates/open-letter-charging-arrangements-embedded-generation
[16] https://www.ofgem.gov.uk/publications-and-updates/update-letter-charging-arrangements-embedded-generation

2.7. These updates, and the continued work on the issue of embedded benefits are part of our forward work programme. This consultation document provides our minded to decision on the CUSC modification proposals which have been submitted to us, along with a draft impact assessment.

Problem definition

2.8. This section provides a high-level summary of issues around the TDR payments which smaller EG can receive. For a more in depth background to the history and issue of the TDR embedded benefit, please see appendix 2.

2.9. Historically, total transmission charges were lower than they are today and the amount of smaller EG was small meaning that the distortions caused by the payments were also relatively low. However, the amount of smaller EG has increased significantly in recent years, while the total amount recovered through TNUoS charges has increased. This combination has led to a large TDR payment being available for smaller EG, which is not available to transmission connected generation or generation over 100MW connected to the distribution system. Figure 1 shows the increase in TDR payments available to smaller EG forecast out to 2021.

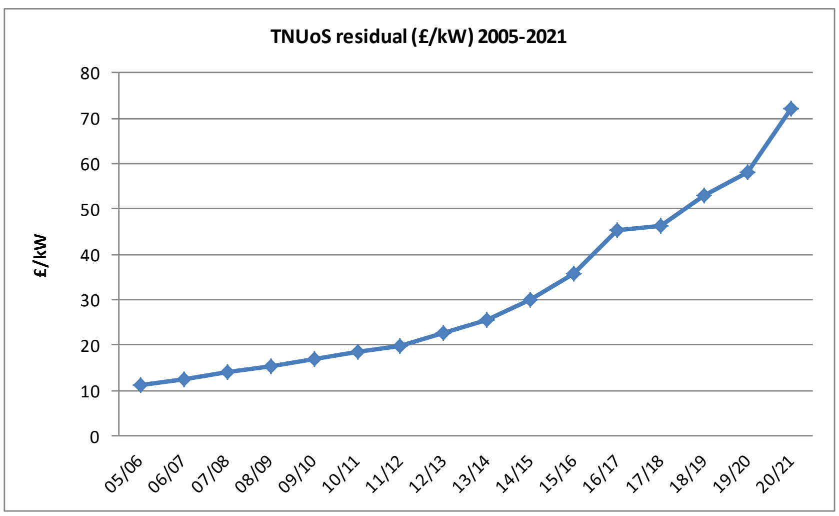

Figure 1- TDR payments available to smaller EG

2.10. Currently the available TDR payment is c. £45/kW[17], predicted to rise to £72/kW in 2021. To put the value of this in context, £45/kW is over double the latest Capacity Market (CM) clearing price[18] and the payment is made for generating

[17] The residual level is the same regardless of location. When locational charges, which can be positive or negative, are added, the amount received by a generator varies from c£40/kW to c£52/kW (2016/17 figures.

[18] CM auction in December 2016, for delivery in 20/21

over three half hour periods (the 'triad' periods). In practice, smaller EG focused on collecting these revenues will generate in 25 or more periods to ensure they hit these triad periods.

2.11. This large payment provides a strong incentive for generators to connect on the distribution system, instead of the transmission system. As an increasing number of smaller EG locate on the distribution system and generate at Triad periods, net demand from the transmission system is reduced at triad. This leads to the revenue recoverable via the TDR being recovered over a smaller charging base. This increases the rate of the TDR charge, and therefore the TDR payments to smaller EG, further escalating the problem. It also increases the cost to consumers, as suppliers have to recover more from their customers to pay those smaller EG generators who generate at triad.

2.12. We believe the size and increase in the TDR payment, as set out in our open letters, has led to the following distortions and outcomes:

- **Dispatch** – Smaller EG generate out of merit[19] to ensure they hit the triad periods;
- **Wholesale price** – By running out of merit, the wholesale market price is distorted and artificially damped at peak times;
- **The Capacity Market** – Smaller EG have a competitive advantage[20] when bidding into the CM, reducing their possible bid prices;
- **Inefficient investment in generation capacity** – A large financial incentive to locate on the distribution system despite it possibly not being the most efficient place to locate; and

2.13. We believe the distortions outlined above will lead to higher consumer costs. More efficient generators are pushed out of the market, while consumers have to pay additional money to allow suppliers to 'offset' their transmission charges. As the money recovered through TNUoS is largely a fixed allowed revenue, where charges are avoided, they will ultimately have to be picked up by other users. Suppliers recover both the TNUoS charges and the cost of payments to smaller EG from consumers, which increases the total costs recovered from consumers.

2.14. We believe the TDR payments to smaller EG constitutes a significant distortion between larger transmission- or distribution-connected generation and smaller EG and that prompt change is required.

[19] See Appendix 5.
[20] Smaller EG have a competitive advantage compared to transmission generation and over 100MW generation on the distribution network, because they can access the TDR payment revenues. This revenue means they can bid into the CM at a lower price.

2.15. As previously stated in our open letters, we believe that the use of the CUSC process is the most appropriate and timely method of addressing the escalating TDR payments. Two CUSC modifications and 23 alternative proposals are now with us for decision. We recognise that there is a tension between the need to deal quickly with the most immediate distortions and the need to ensure the network charging arrangements work as a consistent, coherent whole. We believe that the use of Ofgem's Significant Code Review (SCR) powers on this specific issue would be unlikely to bring about prompt change, as such reviews can take a number of years. We consider that earlier action on this particular issue is preferable due to the potentially lengthier timescales of an SCR, the scale and rate of increase of the TDR payments and the potential for further impacts on the CM and other markets. Including this issue into the Targeted Charging Review could mean at least two further years of escalating distortive payments, meaning additional costs of c£600m21 to consumers and two further years of distortion to CM auctions.

2.16. In addition to the consumer cost, distorted investment and dispatch signals are likely to lead to inefficient allocation of resources and may hinder innovation by allocating resources not to those parties that will use them most efficiently, but those that are able to access these other revenue streams. The presence of non-cost reflective and distortive payments[22] is also bad for competition, as the non-cost reflective revenue streams can more easily be accessed by some parties but not by others, without good reason for the distinction between parties. For a network, it is particularly important that the signals offered encourage efficient use of the system and attract generators to where they are most useful to the system, rather than where they can attract the most income from network charging. We have not seen evidence from workgroups or in response to our two open letters to support the current level of this differential treatment of smaller EG.[23]

The CUSC modification process

2.17. We have two Connection and Use of System Code (CUSC) modifications, and their respective Workgroup Alternative CUSC Modifications (WACMs), with us for decision, which propose solutions to the issues discussed above. As discussed in Chapter 3, we can either accept one, or reject all of the proposed options, or send them back, for example for further analysis in the workgroup, if we consider we are unable to form an opinion based on the information submitted to us.

2.18. The CUSC, is subject to open governance, meaning it can be changed through an industry-led change management process, with modifications being proposed by industry parties. CUSC signatories can raise a proposed modification at any time. Parties who are not CUSC signatories can also raise a modification by being sponsored by a CUSC signatory, National Grid or Ofgem. Proposed

[21] These costs are discussed in more detail in the implementation section of chapter 7.
[22] The allocation of residual costs will always lead to some distortion, but the ability to be paid a cost-recovery charge to help others avoid this charge is highly distortive.
[23]These issues are discussed in more detail in chapter 4.

modifications, will be developed within a workgroup process where relevant, chaired by National Grid, in its capacity as Code Administrator. A full description of the industry led CUSC modification process can be found in appendix 3, but the essentials are set out below.

2.19. Once the modification enters the workgroup phase, workgroup members are able to raise their own alternative proposals (WACMs). The original proposals can only be changed by the proposer.

2.20. Proposals are then developed and assessed according to whether, and how well, they further the applicable objectives outlined in the CUSC. The CUSC objectives are discussed more fully later in this document. After industry consultation, the workgroup will vote on which proposals, including WACMs they feel better and best meet the applicable CUSC objectives, both against the 'status quo' (also referred to as the 'baseline' or 'do nothing') scenario and against the other proposals. At the workgroup voting phase, the CUSC workgroup chair can retain WACMs if they feel that they better meet the CUSC objectives.

2.21. Those that are voted better than the status quo, or are retained by the workgroup chair, go to the CUSC Panel for consideration, and they vote on them against the same objectives.

2.22. Finally, once the CUSC Panel have voted on the original proposals and the relevant WACMs, they will submit their recommendation to Ofgem, alongside the workgroup Final Modification Report (FMR). We will then make a final decision on whether to accept, reject or send back the proposals. Ofgem will make a decision with an assessment against the applicable CUSC objectives, as well as our wider statutory duties.

Output from the workgroups

The original CUSC modifications proposals and WACMs

2.23. The two industry modifications raised aim to deal with two particular defects identified in the CUSC charging methodology. Both were raised on 17 May 2016 and considered by the CUSC panel on the 27 May 2016. Full details of these modifications can be found on National Grid's website.[24] Both of these modifications seek to prevent smaller EG from being able to receive payment equal to the TDR, but would allow smaller EG to retain the inverse of the transmission demand locational signal.

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[24] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/ and http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/.

- CMP264 – Aims to prevent new smaller EG (defined as those commissioning after June 2017), being netted off the supplier's gross demand, and as such, removing their ability to receive the TDR payment as an embedded benefit. Net charging would be retained for existing smaller EG. This was originally intended to be a temporary solution whilst further work was done by Ofgem. This modification was raised by Scottish Power.
- CMP265 – Aims to prevent the output from those generators who hold a CM agreement, from being netted off a supplier's gross demand, and therefore receiving the TDR payment as an embedded benefit. This modification was raised by EDF.

2.24. Both the original modifications go to the CUSC panel for voting, even if not voted by a majority by the workgroup.

2.25. During the workgroup process, over 80 WACMs were raised by workgroup members. These were voted on with the following results:

- 8 unique WACMs were voted as being better than the baseline by the workgroup – 4 of these were applied to both CMP264 and CMP265, with the other four addressing the defect under CMP264 only.
- 15 unique WACMs were put through by the workgroup chair. 14 of these applied to both CMP264 and CMP265, with only one of them applying to CMP264 only. The workgroup chair can retain a WACM if they feel it better facilitates the CUSC objectives.
- In total, this means that 23 unique WACMs, plus the two original CUSC modifications were put through for the CUSC Panel to vote on, and for Ofgem to make a decision on. Full details of the vote can be found in appendix 3.

2.26. All of the WACMs (and Originals) put through, seek to make changes to the TDR[25] payment level, with all of them proposing to reduce it, compared to the status quo. Some of these WACMs would apply changes differently for new and existing generators.

CUSC Panel vote

2.27. The CUSC panel met on 25 November 2016 and voted on the original proposals and the WACMs presented to them. A high level summary of the CUSC

[25] Technically speaking, the modifications move to charging TNUoS Demand Residual (TDR) on half-hourly metered gross demand, rather than half-hourly metered net demand, and specify that an embedded export tariff charge be applied to the metered Triad volumes of Embedded Exports sub-100MW Embedded Generators. In the interest of simplicity, we will refer to the new arrangements as payments to smaller EG or words to that effect.

panel vote is seen below, with further information available in the FMR and in appendix 3.

- **CMP264 –** WACMs 1-7 were voted as being better than the status quo, with WACM 3 receiving the most votes, though there was not consensus.
- **CMP265 –** WACMs 1-7 were voted as being better than the status quo. There was no majority consensus reached, but WACMs 3 and 5 received the most votes.

2.28. A full explanation as to the different features of the WACMs and originals is provided in the next chapter.

3. Options available to us

Chapter Summary

This chapter provides a full explanation of the options presented to us in the Final Modification Report, presented to us by the industry CUSC workgroup, and the key features of each of the different options. It will focus on the level of payments to smaller generators, the treatment of existing generators, transitional arrangements and any additional impacts.

Ofgem decision

3.1. We will make a final decision on the modifications within the FMR, and will take the workgroup vote, the CUSC Panel vote, the evidence in the FMR, responses to this consultation and our statutory duties into account when making a final decision.

3.2. When making a decision, we can approve any option put forward to the CUSC Panel and can go against the CUSC Panel recommendations if we feel it better meets the CUSC objectives and our statutory duties. In the CUSC modification proposal process, Ofgem has the following three options:

- **Accept** – Ofgem accepts one of the options presented to us;
- **Reject** - Ofgem rejects all of the options presented to us; and
- **Send back** – Ofgem can send the modifications back if we feel that more work needs to be done, or further analysis needs to be carried out.

3.3. When making a decision, Ofgem does not have the option to make changes to the modifications submitted to us.

Modification proposals and their characteristics

3.4. In this section we will outline, some of the key characteristics of the modifications, focusing on the following:

- The proposed level of payment to smaller EG;
- The treatment of existing smaller EG, who may be receiving payments under the current arrangements;
- Transitional arrangements – both grandfathering and phasing; and
- Additional impacts.

3.5. All of the CUSC modification proposals (and WACMs) that have been put forward, would reduce the revenue that a smaller EG can expect to receive compared to the 'status quo' scenario.

Features of the modifications and WACMs

3.6. Many of the modifications submitted to us have shared components. These shared components are explained in more detail below, but are:

- The locational signal[26]
- Flooring at zero
- Transitional arrangements – grandfathering[27]
- Transitional arrangements – phasing[28]
- A value of 'x' for either affected generators, and/or grandfathered generators.

3.7. All of the WACMs proposed would replace the current net charging of the TDR charges with a new structure where demand is measured on a gross basis (i.e. gross demand without smaller EG netted off), either for all smaller EG or for a subset of smaller EG. This involves an explicit 'embedded benefit tariff' which is applied to smaller EG (or a subset of smaller EG) exports on a gross basis.

3.8. This proposed new embedded tariff takes the form of a demand locational tariff[29], charged net (as now) plus a new value to replace the current TDR value. This element of the new tariff (or TDR payment to smaller EG) is referred to as the "value of 'x'".

The Locational Signal

3.9. All of the modifications would retain a locational signal for smaller EG, which will be the inverse of the TNUoS demand locational charge. This locational signal would vary dependent on the generators location in the country and charging zone, with it tending to be negative in the North of the system and positive in the South.

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[26] Appendix 1 explains transmission charging in more detail and explains how they are composed of both a locational element, which reflects the relative locational difference in cost a generator has on the system, and the residual component, which is a cost recovery element.
[27] Grandfathering would involve leaving the current arrangements in place for a subset of existing EG. There are different variants of grandfathering, each covering a particular group of customer and payment level. The predominant form that is present in most WACMs retains a payment of £45.33/kW for 15 years for 14/15 CM contract holders and CfD holders.
[28] Phasing options involve a straight-line reduction in the level of payment over three years, with the level reduced by one-third of the difference between the current and final levels in the first year of transition, two-thirds in the second, and removed entirely in year three, leaving the generator with the final payment level.
[29] Smaller EG would see the negative of the locational tariff so that if the original locational tariff results in a payment from demand, it would result in payments to exports from smaller EG.

Generators are charged on their generation over the triad periods, so only face the charges if they are running at these times.

3.10. Smaller EG is seen as 'negative demand' within the GSP group, as explained in chapter 2. As such, all of the modifications will maintain smaller EG facing the inverse of the demand locational signal. In other words, where the locational signal is positive, smaller EG will be paid the locational signal which demand users would pay, and will pay the locational signal which demand users would be charged where the signal is negative.

3.11. The locational signal, which applies to all modifications, will be the base to which the value of the TDR payment (or the value of 'x') will be added.

Flooring payments at zero to prevent smaller EG paying transmission charges in peak demand scenarios

3.12. All of the WACMs and proposals, with the exception of CMP265 original and the "lowest locational" options, would introduce a 'floor at zero' for the transmission charges which smaller EG would see under certain WACMs. As stated above, the locational signal can be either positive or negative, and when combined with lower values of 'x', could mean smaller EG having to pay transmission charges to generate at triad within certain charging zones.

3.13. The "floor at zero" options, would prevent this from happening and would prevent smaller EG having to pay transmission charges if generating at triad, with smaller EG instead receiving £0/kW in certain charging zones. This was intended to prevent the potential negative incentive for smaller EG to not generate, or turn off, at triad periods.

Transitional arrangements – Grandfathering

3.14. Some of the WACMs propose to grandfather a specific subset of generators dependent on whether they commissioned before a certain date, or whether they hold a CfD contract or a CM contract from the 2014 or 2015 CM auctions.

3.15. Most WACMs which propose grandfathering, do so by providing grandfathered TDR payments for smaller EG at £45.33/kW until 2033, with the exception of WACM23 which these payments grandfathers at £34.11/kW for 10 years.

3.16. The two original proposals (CMP264 and CMP265), however, propose grandfathering the status quo arrangements and retain net charging, meaning the TDR payment level would rise to c. £72/kW by 2020/21, according to National Grid's current forecasts.

Transitional arrangements - Phasing

3.17. Phasing aims to soften the impact of changes for smaller EG by reducing the level of payment to smaller EG over a period of three years, reducing by 1/3 a year, arriving at the final level of 'x' on year three. The first reduction of 1/3 occurs on the year of implementation and is a reduction of 1/3 from the level of TDR the year prior to implementation.

Values of 'x'

3.18. CMP264 proposes changing the TDR charge to a gross basis for demand, and removing the TDR payment as an embedded benefit for new smaller EG. CMP265 continues to pay the TDR to smaller EG, but not to those with CM contracts. Other WACMs replace the TDR with another payment. The term "value of 'x'", was established within the workgroup to represent the additional value added to the inverse locational signal, and is applied to all smaller EG, irrespective of their location. As it makes no additional payment to smaller EG, CMP264 effectively has an 'x' value of £0/kW.

3.19. The value of 'x' is intended to represent the measure of the benefit[30] that a smaller EG will bring in terms of avoided transmission costs as compared to larger generation in the same area. The difference in this value of 'x' led to a wide range of WACMs, with it ranging from £0/k (meaning that smaller EG would receive the inverse of the demand locational only) to £45.33/kW (freezing at the level they receive now).

3.20. Below is an explanation of the values of 'x' in the WACMs with us for decision, as well as a more in depth explanation of each of them. Those that are set values are explained in the table, whilst values based on external values or principles, are explained separately. Of the values of 'x' stated below, the WACMs which were voted by the CUSC panel as better facilitating the applicable CUSC objectives only include values of 'x' equal to the generation residual, avoided GSP investment cost and the lowest locational value.

[30] Or in the case of the Generation Residual, preventing other distortions.

Table 2 - Explanation of the values of 'x'

Value of 'x'	Explanation
£0/kW	Smaller EG do not receive any payments above the inverse of the lowest locational signal
Avoided GSP investment cost (last estimate £1.62/kW)	Smaller EG will get the value of National Grid's estimate of the cost of GSP reinforcement which is saved by embedded generators
Generation Residual	Smaller EG face the value of the TNUoS generator residual charge which Transmission Generators and over-100MW generators would pay/be paid
Generation Residual + Avoided GSP investment cost	Smaller EG receive both the value of the avoided GSP investment cost and the generator residual, as explained above.
£20.12/kW + RPI	Based on the estimated cost of transmission reinforcement cost calculated by Cornwall Energy[31] (£18.50/kW) and the avoided GSP investment cost (£.162/kW at last estimate)
Lowest demand locational value	Smaller EG will receive the value of the magnitude of the lowest demand locational signal. This is intended to maintain the full cost differential of the indicative locational signals between charging zones.
£27.70/kW for 5 charging years then Generation Residual	The value at which the embedded TDR payment was at when embedded benefits were last considered in 2013/14 in the National Grid informal consultation.
£32.30/kW + RPI	Based on analysis by Cornwall Energy on the avoided costs that embedded generation can provide.
Demand residual with offshore costs removed	Calculation of what the TDR payment would be if the costs of offshore transmission was removed.
£34.11/kW for 1 year then £20.12/kW +RPI	£34.11/kW based on a four year average of what the TDR level was to 2016/17. £20.12/kW based on Cornwall Energy estimates, as explained above.
£45.33/kW + RPI	Effectively freezing the TDR payment at what it is now, to prevent further increase.

Value of 'x' – Avoided GSP investment cost

3.21. It is recognised that embedded generation (generation connected on the distribution side of the GSP), can offset the need for reinforcement at that GSP, which arises from an increase of demand at that GSP, compared to a transmission generator connected at the same location. This was recognised in National Grid's review[32] in 2013/14, where the average annuitized cost of the infrastructure reinforcement was taken and divided by the average capacity delivered by a supergrid transformer (the cost of the supergrid transformer is not included) to provide a unit cost of the avoided infrastructure reinforcement at the GSP, last calculated as £1.62/kW in 2013/14 prices.

[31] http://www.theade.co.uk/medialibrary/2016/05/16/09ca4432/A%20review%20of%20Embedded%20Generation%20Benefits%20in%20Great%20Britain.pdf.
[32] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937458

3.22. Options which include the avoided GSP investment cost as a value of 'x' propose to update this figure at the beginning of every price control, with RIIO infrastructure costs.

Values of 'x' – TNUoS generator residual

3.23. National Grid's allowed revenue, recovered through the TNUoS charge, is recovered partly from generation, and partly from demand. The charges for generation and demand have both a locational component, which varies according to the user's location on the network, and a residual component, to ensure that the full allowed revenue is recovered where it is not fully recovered through the locational element.

3.24. Historically, the residual components of the charge have always been positive, however, the generator residual charge, due to a number of factors[33], is forecast to go negative, meaning that transmission, and over 100MW EG, would receive a payment or reduced charge related to the TNUoS generation residual charge. Therefore, the WACMs which include the generator residual charge as a value of 'x' would ensure that smaller EG would be paid the value of the generator residual charge if it goes negative, in the same way as transmission and over 100MW EG would. It also means that, if the generation residual charge is positive, some smaller EG would have a reduced benefit. Some smaller EG in certain areas would not, have to pay the full generator residual charge due to the proposed 'floor at zero' element in these options.

3.25. Ofgem have publically stated[34] that we do not consider a negative residual charge to be consistent with the development of an efficient transmission network and a well-functioning wholesale market. We intend on doing further work to address this issue as part of the upcoming TCR.

Value of 'x' – Lowest demand locational value

3.26. The lowest demand locational as a value of 'x' adds a value equal to the magnitude of the lowest locational demand TNUoS tariff for all smaller EG. This would be updated annually when the transmission tariffs are calculated.

3.27. This value of 'x' would maintain the relative locational relationship between different smaller EG and prevent the sum of the locational and 'x' value (the total embedded benefit) from being negative for smaller EG. A negative value would mean that there would be an incentive for smaller EG in those zones to turn off over triad

[33] The generation residual is set to go negative due to a cap, of 2.5 euros, on the charges that can be applied to generation, and due to the increased costs associated with offshore generation charges.
[34] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP255/.

and not generate, or they would be required to make a payment. This option prevents the need for a floor at zero.

Value of 'x' – Removed offshore costs

3.28. This value of 'x' is equivalent to what the TDR charge would be for demand users, if the costs associated with offshore transmission were removed. This option may reduce the embedded benefit to smaller EG in the short term, but, according to current projections, would continue to rise upwards of £50/kW by 2021. This option was originally intended to recover the costs of the offshore transmission works through a £/MWh charge, in the same method as other environmental policies, in recognition that the rising offshore costs within the TNUoS charge were driving up the TDR element of the demand charge. However, this option was outside of the scope of the workgroup.

3.29. The table below sets out the key features of all of the WACMs (and Originals) presented to Ofgem for decision. All options retain the inverse demand locational signal for smaller EG and all of the options, excluding CMP265 original and the "lowest locational" options, introduce a 'floor at zero' to prevent smaller EG having to pay if generating over triad and are in a demand zone where the inverse of the locational and value of 'x' total is negative.

Table 3 - Key features of the proposed modifications

<table>
<tr><th>WACM Number</th><th>Affected Generator Value of 'X'</th><th>Affected Generator</th><th>Grandfathered Generator</th><th>Level of Grandfathering</th><th>3 Year Phasing</th></tr>
<tr><td>264 Original</td><td>£0/kW</td><td>All commissioned after 30/06/17</td><td>All commissioned before 01/07/17</td><td>Net charging retained</td><td rowspan="6">N</td></tr>
<tr><td>WACM 19</td><td>£0/kW</td><td>All commissioned after 30/06/17</td><td>All commissioned before 01/07/17</td><td rowspan="4">£45.33 + RPI until 2033</td></tr>
<tr><td>WACM 20</td><td>£27.70/kW for 5 charging years then Generation Residual</td><td>All commissioned after 31/10/18</td><td>All commissioned before 01/11/18</td></tr>
<tr><td>WACM 21</td><td>Lowest locational value</td><td>All commissioned after 31/10/18</td><td>All commissioned before 01/11/18</td></tr>
<tr><td>WACM 22</td><td>£0/kW</td><td>All commissioned after 30/06/19 and multiyear-newbuild CM/CFD contracted after 14/15</td><td>All commissioned before 30/06/19 excluding multiyear-newbuild CM/CFD contracted after 14/15</td></tr>
<tr><td>WACM 23</td><td>£34.11 for 1 year then £20.12+RPI</td><td>New excluding 14&15 CM/CFD</td><td>Existing generators and 14&15 CM/CFD</td><td>£34.11 + RPI for 10 years then move to AG</td></tr>
</table>

265 Original	£0/kW	Generator with CM Contract	Generator without CM Contract	Net charging retained	N
WACM 1	Generation Residual	All move to new charging (TDR charged gross)	No Grandfathering	No Grandfathering	N
WACM 2	Generation Residual				Y
WACM 3	Avoided GSP investment cost				N
WACM 4	Avoided GSP investment cost				Y
WACM 5	Generation Residual + Avoided GSP investment cost				Y
WACM 6	Lowest locational value				N
WACM 7	Lowest locational value				Y
WACM 8	£32.30/kW				N
WACM 9	£34.11 for 1 year then £20.12+RPI				
WACM 10	45.33/kW				
WACM 11	Demand residual with offshore costs removed				
WACM 12	Generation Residual	All excluding 14&15 CM/CFD contract holders	14&15 CM/CFD contract holders	£45.33/kW + RPI until 2033	
WACM 13	Avoided GSP investment cost				
WACM 14	Generation Residual + Avoided GSP investment cost				
WACM 15	Lowest locational value				
WACM 16	£20.12 + RPI				
WACM 17	£32.30/kW				

WACM 18	Demand residual with offshore costs removed				

Consequential modifications under the CUSC and Balancing and Settlement Code (BSC)

3.30. It is worth noting at this point, that there are 4 other modifications which go alongside CMP264 and CMP265 and enable the implementation of the modification proposals.

3.31. CMP269 and CMP270 are CUSC modifications to make changes to other sections of the CUSC. Both CMP264 and CMP265 are charging modifications, which if approved, would require changes to section 14 of the CUSC (Charging Methodologies) and are assessed against the applicable charging objectives. As a result of CMP264 and CMP265, it was recognised that other sections of the CUSC may need consequential changes (namely section 3 and 11) and so CMP269 and CMP270 were raised to enable these changes and will be assessed against the non-charging objectives.

3.32. P348 and P349 are two BSC modifications which are also consequential to CMP264 and CMP265 and make changes to the BSC to enable the data transfers/collection to occur so that both CMP264 and CMP265 can be implemented.

4. Assessment against decision making criteria

Chapter Summary

This chapter sets out how we have qualitatively assessed the options presented to us, against the applicable CUSC objectives and our statutory duties, and in doing so, refine the number of options for further consideration.

Question 3: Do you agree with our interpretation of the applicable CUSC objectives?
Question 4: Do you agree with our assessment against the applicable CUSC objectives and statutory duties? Please provide evidence for any differing views.
Question 5: In our assessment against the objectives, do you believe there are any relevant assessments we have not taken into account?
Question 6: Do you agree with our assessment that, in this instance, grandfathering as set out in the WACMs would be unlikely to best facilitate the CUSC objectives when compared to the other options available to us?
Question 7: Do you agree with our assessment that the value of the avoided GSP investment cost best facilitates the applicable CUSC objectives?
Question 8: Do you agree with our assessment of the impacts on security of supply? Please provide evidence for provided views.
Question 9: Please provide evidence to show if there are other cost savings which small EG drive in comparison to larger (over 100MW) EG on the distribution system.
Question 10: Is there other evidence that payment above avoided GSP/generation residual would better facilitate the applicable objectives?
Question 11: Do you believe you have a legitimate expectation or contractual right for the continuation of TDR payments? If so, please provide evidence.

Methodology and Approach

Ofgem's decision-making framework

4.1. We, in our role as regulator of the GB gas and electricity markets, are required to consider the merit of any proposed changes, and when appropriate, direct that the modification be made.

4.2. Before making any decision directing that a modification be made, we must satisfy ourselves that:

- the modification better facilitates the applicable CUSC objectives[35] as compared with both the status quo and also any alternative modifications put before it in the modification report; and
- the modification is consistent with Ofgem's statutory duties under primary legislation and EU law. The relevant general principles of EU law in this context overlap to some extent with CUSC objectives and include promotion of effective competition, non-discrimination, transparency and proportionality in charging structures.

Decision against the applicable CUSC objectives

Applicable CUSC objectives

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. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and

e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

CUSC Objective (a) - Facilitating Competition

4.3. In order to assess whether each option presented to us better facilitates competition, we need to decide whether each option is better, worse or neutral in terms of facilitating competition than the status quo. To do this, we have considered

[35] CUSC objectives for changes to the Use of System charging methodology are set out in standard condition C5 of National Grid's transmission licence, available here: https://epr.ofgem.gov.uk//Content/Documents/Electricity%20transmission%20full%20set%20of%20consolidated%20standard%20licence%20conditions%20-%20Current%20Version.pdf

the following five features which are present in the options we are considering. These are:

- The level of TDR payment to smaller EG (the value of "x")
- Whether the options expose smaller EG to the TNUoS Generation Residual
- Whether and how the options prevent disincentives on smaller EG to generate at peak triad periods
- Whether and how the options 'grandfather' existing TDR payments to smaller EG
- Whether and how the options use phased implementation

4.4. In the sections below, we set out our assessment of each of these features and whether each feature is better, worse or neutral in terms of facilitating competition than the status quo. After doing this, we set out our provisional assessment of whether overall each option in front of us is better, worse or neutral in terms of facilitating competition than the status quo, taking account of our assessment of the features we have considered in the round.

The level of TDR payment to smaller EG (the value of "x")

4.5. Competition is best facilitated by non-discriminatory arrangements that do not inherently favour particular market participants. Our regulatory stance on promoting effective competition notes our key role in ensuring that the energy system arrangements help to create the conditions in which competition can flourish, such as making sure access and charging arrangements are non-discriminatory and that all market participants compete on a level regulatory playing field. A level playing field will lead to the most efficient generators succeeding, and those who are less efficient doing less well. Charging arrangements that lead to an un-level playing field, if not justified, may hinder competition by allowing more expensive types of generation to operate in place of cheaper ones, increasing consumer costs.

4.6. Smaller EG are currently treated differently than larger generators and can receive TDR payments if they generate over the triad periods. Larger generators cannot access this revenue.

4.7. All of the options presented to us limit or reduce the level of TDR payments to smaller EG compared to the status quo, and so should all lead to some improvement in competition between smaller EG and other generators, as the current competitive advantage received by smaller EG will reduce. An exception is those WACMs that retain the TDR with Offshore Costs removed. While there may be some modest reductions, payments to smaller EG under this option are still expected to rise to upwards of £50/kW by 2021.

4.8. Our provisional thinking is that the level of benefit to the transmission network provided by smaller generators is limited to the avoided cost of GSP infrastructure. We discuss the evidence for this and other payment levels in the section looking at objective (b), which assesses the options against cost-reflective charging. We would therefore expect that any option that reduces the level of payment to nearer to that level to deliver improvements to competition, with options that reduce the payment to that level to be best for competition.

4.9. In the table below, we set out our provisional assessment of the payment level options available, whether that level is better, worse or neutral in terms of facilitating competition than the status quo, and provide examples of WACMs which contain this level of payment to smaller EG.

Table 4 Payment level for smaller EG

Competition - Payment level for smaller EG		
Level	**Examples**	**Impact on competition compared to status quo**
Low (e.g. Avoided GSP, Generation Residual)	264, WACMs 1-5, 12-14, 19, 22	Better than status quo
Medium (e.g. lowest locational, £20.12)	WACMs 6-9, 15-17, 20, 21, 23	Better than status quo
High, but capped	WACM 10	Better than status quo
High, uncapped	WACMs 11, 18	Neutral
Status quo	265, Status Quo	Neutral

Options including the TNUoS Generation Residual

4.10. A number of options expose[36] smaller EG to the TNUoS generation residual (TGR), a cost-recovery charge. The TGR is forecast to turn negative in coming years, and it has been argued that exposure of smaller EG to the negative TGR will prevent a possible situation where larger generators receive revenues that smaller EG cannot access.

4.11. Providing the same payment to smaller EG may therefore be beneficial to competition. However, we believe the specific approach outlined in the proposals would not improve competition overall, because some smaller EG will benefit from this charge if it turns negative, but will not be fully exposed to this charge when it is positive, due to the mechanism that prevents smaller EG facing positive transmission charges when they generate at peak (by providing a zero payment floor).

[36] The extent of this exposure is limited by the floor at zero option in some circumstances

4.12. In the table below, we set out our provisional assessment of the inclusion of the TNUoS Generation Residual, whether the inclusion of this feature is better, worse or neutral in terms of facilitating competition than the status quo, and provide examples of WACMs which contain this feature.

Table 5 - Assessment of options including the TNUoS Generation Residual

Competition - TNUoS Generation Residual		
Feature	**Examples**	**Impact on competition compared to status quo**
With TGR	WACMs 1, 2, 5, 12, 14, 20	Neutral
Without TGR	All other options	Neutral

4.13. Given there are elements of these modifications which we think could improve competition and elements which we think could worsen competition, we therefore consider the inclusion of the TGR to be neutral for competition.

Options to prevent disincentives for smaller to generate at peak periods

4.14. There are two options presented to us to prevent smaller EG facing negative transmission charges when they operate at peak triad periods, which would provide a disincentive to generate at peak periods. These are a "floor at zero" option and a "lowest demand locational" option.[37]

4.15. Most options presented to us use a "floor at zero" method to ensure that smaller EG don't face charges to generate during triad periods. This removes an incentive not to run at peak time. The lowest demand locational option aims to remove this incentive by paying sub-100MW EG a payment (~£22.50/kW in 2020/21) that is equal to that year's lowest TNUoS Demand Locational. This preserves the geographical differences in locational signals within the smaller EG market better than the floor at zero options but preserves a greater level of payment to smaller EG when compared to larger generators. The floor at zero provides less of a competitive distortion between smaller EG and other generators but it dampens the geographical signals faced by smaller EG.

4.16. Based on the tariffs for 2016/17, under the floor at zero option for Avoided GSP, seven zones have tariffs adjusted by the floor at zero and the average adjustment is £1.27/kW. The lowest locational options adjust all zones and in 16/17 the additional revenue is £5.09/kW. These figure will change each year, but the lowest locational option affects all zones and provides more revenue to smaller EG in each year. Of the two options, the floor at zero option may therefore be, on balance, marginally better for competition between all generators as it removes the bulk of the distortion between smaller EG and larger generators, and the new locational

[37] These options are set out in more detail in Appendix 6

distortion added by the floor is small in scale. The lowest locational preserves locational signals with the smaller EG market more effectively, as no zones have their charges floored at zero. This preserves the differences between the highest and lowest locational charges for EG, but maintains a larger distortion with larger generators. We think that both options have advantages, and are both assessed as neutral against the status quo.

4.17. In the table below, we set out our provisional assessment of the methods used to prevent disincentives to generate at peak time. We then set out whether the inclusion of this method is better, worse or neutral in terms of facilitating competition than the status quo, and provide examples of WACMs which contain this method.

Table 6 -Assessment of options to prevent disincentive to generate

Competition - Methods of preventing disincentives to generate		
Method	**Examples**	**Impact on competition compare to status quo**
Lowest TNUoS Demand Locational	WACMs 6, 7, 15, 22	Neutral
Floor at Zero	All other options	Neutral

Options which include grandfathering of existing payments to smaller EG

4.18. This section assesses the impact of the proposed grandfathering (in the mods submitted to us for decision) and whether this grandfathering is better, worse or neutral in terms of facilitating competition compared to the status quo.

4.19. Several options include grandfathering of existing TDR payment levels for certain classes of generator. This is through explicit grandfathering of certain smaller EG, or by applying the proposed changes only to smaller EG commissioned after a specific date.

4.20. The grandfathering options which have been presented to us all include i) the locking in of the TDR payments for the grandfathered smaller EG and ii) the immediate move to the new TDR payment level for all other smaller EG. These proposals improve competition between larger generators and smaller EG, since the level of TDR payments to both grandfathered and non-grandfathered smaller EG are lower in these options than in the status quo. However, this effect has been assessed in the section on the level of payment above and hence is not considered again here.

4.21. The grandfathering options introduce a significant new distortion to competition between two types of smaller EG – those who receive grandfathering and those who do not. This distortion is both large and enduring as the grandfathering options preserve this distortion for many years.

4.22. It has not been suggested to us that any party has a contractual right or legally enforceable legitimate expectation that it should continue to receive TDR payments based on the current methodology over any particular period. Current charging arrangements set out in the CUSC expressly provide for the possibility of change in the form of the industry-led CUSC modification process. Against that background, any investor in smaller EG can reasonably expect that the level of TNUoS charges it is required to pay (or the level of payment it receives) are subject to regulatory change – in the same way that its other operating costs and revenues are subject to change. Investors in smaller EG can reasonably expect to bear the risk of changes[38] to charging arrangements and to develop their business accordingly.

4.23. Generators, including CM/CfD holders, would have estimated future revenues and costs and set their CM/CfD bids accordingly. We do not know, and cannot comment on, what proportion of smaller EG that have secured CM contracts and CfDs have in fact relied on the continuation of current TNUoS charging arrangements in this way. We note, however, that we are not aware of any provisions in the CUSC, CM contracts or CfDs that provide for grandfathering of TDR payments. There are express provisions in the CfD standard terms to equalise fluctuations for BSUoS and transmission losses, but the protection does not extend to TDR payments. [39] It is worth noting that, in a government consultation last year on changing the basis of the capacity market supplier charge from net to gross demand, there were calls for the grandfathering of capacity that was secured in an agreement in the 2014 and 2015 capacity auctions. BEIS recognised the challenge from some investors but was ultimately of the view that, to the extent CM participants assumed future revenue as a result of this potential embedded benefit, they should do it at their own risk. [40]

4.24. We do have concerns that options that leave these TDR payments in place for a subset of smaller EG and not others leave a distortion in place between the grandfathered smaller EG and larger EG. They also introduce a new distortion between those smaller EG who benefit from grandfathering and those who do not. These payments may mean that some smaller EG are not exposed to the same competitive pressures[41], don't respond to the same market signals,[42] or provide services for which they are the most efficient provider.[43]

[38] Such changes would only be permitted or undertaken where they were in line with the requirements of the statutory scheme.

[39] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267649/Generic_CfD_-_Terms_and_Conditions__518596495_171_.pdf

[40] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/563444/CM_Consultation_detailed_proposals.pdf

[41] Generators that innovate may still be unable to compete where they don't have access to the grandfathered revenue streams that their competitors do, despite the improvements or efficiency savings that they have developed. This may prevent innovation or improved efficiency feeding through to consumers as lower costs, or prevent new entrants entering the market.

[42] This will potentially increase costs for consumers. See Appendix 5 on Efficient Market Operation for more information.

[43] Grandfathered generators may be able to offer other services at a lower cost than those who are not

4.25. We have concerns that the introduction of such a competitive distortion in a sector that is rapidly changing (due to technological developments) could be harmful to innovation. In addition, options that include grandfathering would require an immediate change for those generators that are not covered by grandfathering. This could mean rapid behavioural change for those operators, which could to some extent add additional unpredictability in dispatch.

4.26. Putting aside the benefits to competition from lower TDR payments in options which include grandfathering, which are covered in the section above, we consider that options that include grandfathering are likely to introduce a new distortion in that respect may be worse than the status quo. Options which include future cut-off dates for grandfathering are also likely to be worse than the status quo. Under these options it is likely that there will be an increase in build out as developers try to complete planned projects, and possibly begin new ones, to try and secure the favourable grandfathering arrangements. Through this, the options will actually increase the distortion for a period of time.

4.27. In the table below, we set out our provisional assessment of the types of grandfathering features present in various options, whether the inclusion of this type of grandfathering feature is better, worse or neutral in terms of facilitating competition than the status quo, and provide examples of WACMs which contain this feature.

Table 7 - Assessment of grandfathering features

Competition - Grandfathering		
Type of grandfathering feature	**Examples**	**Impact on competition compared to status quo**
No Grandfathering	265, WACMs 1-11	Neutral
Grandfathering for CM/CfD	WACMs 12-18, 23	Worse than Status Quo
Commissioned before a given date – near future	264, WACM 19	Worse than Status Quo
Commissioned before a given date – further out	WACMs 20-22	Worse than Status Quo

Options which include phased implementation

4.28. A number of options available to us including a phased period of implementation. This is a transitional arrangement where the level of payments to generators is phased in over three years.[44] This has the function of moving from one

grandfathered, such as power or services, due to TDR revenue. This will lead to further distortions, as while those direct costs may be lower, overall system costs may be higher, for example is smaller EG is receiving both ancillary service revenue and payments for reducing a suppliers' transmission charges.

[44] The level of payment to generators decreases from the level in place the year before implementation, down to the level set out in that particular option. The final payment level is reach in the third year after implementation.

regime to another more slowly, and provides a slightly longer, though reduced, forward revenue stream. This will also mean that smaller EG will continue to receive additional revenue streams that other generators cannot access for a longer period of time.

4.29. As discussed in the sections above, our preliminary view is that options that provide different classes of users with different revenue streams have the potential to lead to reduced competition if not well justified. Whilst there is an argument that phasing will mean that smaller EG can continue to access different revenues to other generators, phasing provides industry and investors more time to adapt to the changes, and is only for a short period. In addition, the level of payment decreases over that time compared to status quo which is likely to be beneficial to consumers. We expect that phasing will preserve some distortions to market signals[45] but for only a shorter period, with the distortions reducing over the transitional period. In contrast, grandfathering includes much more significant revenues over a longer period.

4.30. We think that in this particular situation, phasing is justified due to the scale of the changes and the potential impact on security of supply. Allowing a gradual introduction of this significant change will provide time for generators to adapt their dispatch and business models, which will minimise short term security of supply pressures that could emerge from an immediate change in dispatch behaviour. During this transitional period, we are proposing to undertake the TCR which will consider the other benefits received by smaller EG alongside other matters. We think that any decision on transitional arrangements needs to be made on the facts of the particular case, and should not be taken to create any general precedent or expectation of phasing in other types of cases.

4.31. Our provisional thinking is that both immediate and phased implementation routes would be neutral for competition.

4.32. In the table below, we set out our provisional assessment of the presence of phasing in various options, whether the inclusion of phasing is better, worse or neutral in terms of facilitating competition than the status quo, and provide examples of WACMs which contain phasing.

[45] As described in footnote 13 above.

Table 8 - Assessment of phasing options

Competition - Phasing		
Presence of phasing	**Examples**	**Impact on competition compared to status quo**
With Phasing	WACMs 2,4,5,7	Neutral
Without Phasing	All other options	Neutral

Overall assessment of impact on competition

4.33. In the table below, we set out our provisional assessment of whether overall each option in front of us is better, worse or neutral in terms of facilitating competition than the status quo, taking account of our assessment of the features we have considered in the round.

Table 9 - Overall assessment of impact on competition

Competition - Overall	
Examples	**Impact on competition compared to status quo**
264, WACMs 1-10, 12-17, 19, 23	Better than status quo
265, WACMs 11 & 18	Neutral
WACMs 20-22	Worse than Status Quo

4.34. Overall, it is our provisional view that CMP264 Original, WACMs 1-10, 12-17, 19, and 23 would lead to an improvement in competition. CMP265 and WACMs 11 & 18 are likely to be neutral against the objectives. WACMs 20-22 are likely to be worse than the status quo.

CUSC Objective (b) - Cost-Reflective Charging

4.35. This section sets out how we have assessed the options in front of us in terms of whether each option is better, worse or neutral in terms of facilitating cost-reflective charging than the status quo.

Value of the payments to smaller EG

4.36. While a large number of modification proposals are available, there are only a small number of options of payment levels to replace the current TDR payment to smaller EG. As set out in Chapter 3, the key options are the avoided GSP cost, the generation residual, payment equivalent to the lowest demand locational, payment levels based on historic levels, and payment levels based on Cornwall's analysis[46] of the value of embedded generation.

4.37. Users who benefit from the network should face charges that broadly reflect the costs that they impose on the network, as when faced with the true cost of their behaviour, they are more likely to make efficient choices.[47] Where payments are made to network users through negative charges these should reflect the benefit that the system gets from those network users. Our provisional view is that the current payments made to smaller EG by suppliers for offsetting their transmission system demand are not cost reflective, as the payments do not reflect the level of savings that smaller EG confer on the transmission system. We would also note that options that provide grandfathering of the existing level of TDR to certain users are, for those users at least, not cost reflective and guarantee the non-cost reflective level for extended periods. The TNUoS demand locational charge aims to represent the likely incremental costs associated with consuming energy at particular points on the network. The avoidance of these charges through the use of smaller EG can generally be considered cost-reflective. TDR charges, on the other hand, are cost recovery charges, in that they recover the remaining revenues that are do not vary with use. Economic theory suggests that cost recovery charges should be collected in the least distortive way and should not be easily avoidable.

Avoided GSP investment

4.38. Our provisional view is that the replacement of the TDR payment with the avoided Grid Supply Point (GSP) costs have the strongest principled arguments, when assessed against the CUSC objectives. This option would reduce the TDR payment to one which reflects long run cost savings achievable on the system from lower need to reinforce the points where the distribution system meets the transmission system.

4.39. Analysis produced for the CMP264/265 workgroups and included as a supporting document with the CMP264/265 FMR[48] argued that generators impose the same cost on the transmission system whether they are embedded within distribution systems or connected to the transmission system. The exception to this is the sections of the network that connect the transmission and distribution networks.

[46] http://www.theade.co.uk/medialibrary/2016/05/16/09ca4432/A%20review%20of%20Embedded%20Generation%20Benefits%20in%20Great%20Britain.pdf.

[47] The efficient choices of particular relevance are dispatch (when power is generated) and siting (where to build plants, and which plants are kept running, refurbished or closed). In theory, where more efficient choices are made, there is less need for actions to manage inefficient use, such as constraining generators off, and less need for reinforcement of the network, as generators choose to site where their activities impose the least cost on the network, and benefit from lower charges as a result. This transfers to lower costs for consumers.

[48] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937458

4.40. The analysis presents the outcome of load flow analysis of the effect on the transmission system of transmission- and distribution-connected generation at the same Grid Supply Point (GSP), using the current version of National Grid's transport model.

4.41. According to the presentation, the analysis "shows that identical flows result from connecting generation at either the transmission or the distribution level.

4.42. The analysis suggests that for a model system[49,] adding 450MW generation to the distribution or transmission system resulted in exactly the same change in transmission system network size (both reducing the size of the network by around 0.5%).50

4.43. If this analysis is correct, then the transmission system is affected by generation whether it is placed at the transmission or embedded level, with the exception of the connections between the transmission and distribution networks (the GSP infrastructure), which will have lower flows if the generation is distribution connected (unless the GSP exports).

4.44. National Grid's 2013/14 embedded benefits review[51],[52] established that the cost of grid supply point infrastructure investment (GSP investment) is the only evidenced cost that embedded generation can help to avoid. Through the workgroup process we have seen little evidence that a payment above this would be reflective of system savings.

4.45. National Grid's review states "At the majority of grid supply points (GSPs) where demand is taken off the transmission system, there can be a benefit from embedded generation as it offsets the need for reinforcements arising from increases in this demand. Such reinforcements occur local to the GSP. A significant proportion of these costs are covered by connection charges, and it is only the infrastructure costs which would be liable to be recovered via TNUoS charges."

4.46. The average annuitized cost was determined as £1.58/kW in 2012/13 prices. These were derived from eighteen NGET schemes assessed from their RIIO-T1 price control submission, and ranging from a few pence/kW to £4/kW

[49] Using 2016/17 National Grid Transport and Tariff Model, with 450 MW of generation added via demand reduction (embedded) or transmission at Norwich 400KV substation (which includes both demand and generation at the same Grid Supply Point)
[50] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937458 , page 4.
[51] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/
52 http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=29996

4.47. A National Grid chaired embedded generation benefit focus group was held in May '13 with a range of industry parties, where National Grid presented their evidence that avoided GSP costs could be recognised in most GSPs, though not necessarily in exporting GSPs[53]

4.48. The Association of Decentralised Energy, NERA and Imperial College produced a report[54] which focuses on their analysis of the shortfalls of the current methodology for producing locational signals.[55]

4.49. In this report they note that "two (otherwise identical) generators impose the same cost on the transmission system, irrespective of whether they are embedded within distribution systems or connected to the transmission system. There should also be no difference between the transmission costs imposed on the system (per kW of generation capacity) by embedded generators with capacities above or below 100MW, if they are designed and operated in an identical way in other respects. The current approach of setting different charges for different types of generation depending on whether they are embedded or not and depending on size does not reflect the fact that they impose the same costs on the transmission system." This aligns to the analysis presented in the workgroup discussed above.

4.50. Based on our assessment of the payment level options, our provisional view is that a payment of the avoided GSP costs is most well-justified. It could therefore be considered that additional payment above the avoided GSP costs is not cost-reflective, but that any value that moves closer to the avoided GSP costs is more cost-reflective than the status quo arrangements.

4.51. A number of options provide this payment to smaller EG and are, in our view, the more cost reflective options compared to the status quo. They replace the current TDR payment with an evidenced payment which reflects cost savings that may be achievable on the transmission system as the result of the construction and connection of smaller EG. While this payment is not locational, it is possible that it can be updated through price controls with forward-looking infrastructure costs.

Payments based on historic levels and Cornwall Energy estimates

[53] Embedded generators export their power onto distribution networks. In most cases this nets with demand also connected to the distribution network, but in some areas the exported power can exceed local demand from time to time resulting in distribution systems exporting power onto the transmission system. These areas are referred to as exporting GSPs.

[54] http://www.theade.co.uk/medialibrary/2016/09/30/52aeba1b/160923%20NERA-Imperial%20Report%20to%20ADE%20on%20Embedded%20Benefits.pdf

[55] NERA argue that the current locational demand signal is deeply flawed and needs to be looked at. In their opinion this should be done before making changes to net charging regime. They also note that there are significant behind the meter generation and demand reduction impacts associated with a move to gross charging.

4.52. A number of proposals set payments to smaller EG at historic TDR levels and are intended to provide continuity of revenue for investors. These levels are not reflective of the benefits to the transmission system of smaller EG and, as discussed previously, are difficult to justify as changes in levels of charges are foreseeable to a prudent and informed investor who understands the network charging objectives and arrangements. These options would also increase consumer cost when compared to more cost-reflective options.

4.53. A number of options use values[56] based Cornwall's analysis on the avoided transmission infrastructure cost benefits of smaller EG.[57] Cornwall's analysis suggests that EG can save significantly more reinforcement cost than recognised by the Avoided GSP infrastructure costs. The Cornwall analysis does not draw a distinction between cost recovery charges and cost reflective charges, suggesting EG can save costs in relation to expenditure which has already happened, which is not feasible. In addition, we think their estimate of savings available is flawed.

4.54. Cornwall's analysis states that 1MW demand reduction should be charged in the same way a 1MW increase in embedded generation. We agree that from a physical perspective, a unit of demand reduction (at a given point on the distribution network) should have the same implications as a unit of distributed generation. Therefore, when cost reflective charges are being considered or applied, it would be reasonable to pay them the same amount. On the other hand, for cost recovery charges, the physical impact of different uses and users on the network is less relevant, as these charges are not related to any costs that are reduced as a result of either actions. The aim in setting cost recovery charges is therefore minimising distortion, as the costs to be recovered can't be avoided. An additional unit of generation cannot reduce historic costs of the network, though it can reduce marginal costs of running the network.

4.55. Cornwall's analysis states the cost of the National Grid planned future investments average out at £18.5/kW. This estimate is based on the mean of a range of new transmission projects between £4.5/kW and £241/kW, without explanation of whether the use of embedded generation in these particular situations would have been able to avoid the need for these projects.

4.56. The analysis assumes that EG offsets transmission investment on a one for one basis. We do not agree with this assumption. As discussed above, EG's impact in respect of wider transmission investments (such as the projects included in Cornwall's estimate) depends on its location relative to the investment, is similar to that of transmission-connected generation, and is broadly reflected by locational TNUoS signals. For example, investment in HVDC bootstraps is driven by both EG and transmission-connected generation in the North (and demand in the South) and

[56] Options using £20.12/kW, and £32.30/kW are based on Cornwall analysis.

[57] http://www.theade.co.uk/medialibrary/2016/05/16/09ca4432/A%20review%20of%20Embedded%20Generation%20Benefits%20in%20Great%20Britain.pdf.

its costs are reflected in the locational charges that these generators face. It is the location of these generators that drives the investment, not the voltage at which they are connected.

4.57. The Cornwall approach appears to be, in effect, a simplified version of the approach that is used to determine incremental locational charges – it is not clear what the advantage of their analysis is over that model already used to derive TNUoS locational charges.

TNUoS Generation Residual (TGR)

4.58. As a cost-recovery and reconciliation element, the TGR is not designed for cost reflectivity, but for the recovery of those costs not recovered by the generation locational charges. The main arguments for including the generation residual in the value of x are around competition, and as such are covered in the previous section.

Offshore costs

4.59. Options that offer smaller EG a payment equal to the value of the TDR with the offshore costs removed are not cost reflective, but do function to reduce the consumer costs of these payments. However, with the payments expected to rise to upwards of £50/kW by 2021, this option is unlikely to significantly address the distortions identified in the defects.

The Floor at Zero and Lowest TNUoS Demand Locational methods of preventing disincentives to generate at peak periods

4.60. Most options presented to us use a "floor at zero" method[58] to ensure that smaller EG don't face charges to generate during triad periods. This removes an incentive not to run at peak time, which was seen in the workgroup as having both security of supply implications, and also revenue implications, as it was not clear how revenues could be recovered from non-CUSC signatories. While this is not cost reflective, our view is that the impact is relatively small.

4.61. Another method[59] uses a payment equal to the lowest TNUoS demand locational to "cancel out" any positive charges to smaller EG. This option pays more to all smaller EG than the floor at zero option but preserves the geographical differences in locational signals that are experienced by smaller EG. The lowest locational will change each year and the future level of payment is uncertain, and from a cost-reflectivity standpoint we do not see that there is a link between the value of the lowest locational in one demand area and the benefits provided by smaller EG in all areas. There are also limited competition benefits as smaller EG will

[58] Described in full in appendix 6.
[59] Also described in full in appendix 6.

continue to receive significantly more revenue than other generators, even if competition between smaller EG is improved by more accurate locational signals. We therefore think that on balance, the Floor at Zero method is less distortive and so better for competition.

Overall assessment of impact on cost-reflectivity

4.62. This table sets out our provisional assessment of whether overall each payment level option in front of us is better, worse or neutral at facilitating CUSC objective (b) when compared to the status quo, taking account of our assessment of the options we have considered above in the round. While we consider several of the options to be non-cost reflective in absolute terms, in moving closer to a cost reflective level they are more cost reflective than the status quo, and so better facilitate the code objectives.

Table 10 - Assessment of cost-reflectivity

Cost-reflectivity			
Payment level	**Examples**	**Cost-reflectivity**	**Compared to Status Quo**
£0	264	Does not include identified benefits of EG	Neutral
Avoided GSP	WACMs 3, 4, 13	Supported by NG 2013/14 review	Better than status quo
Avoided GSP + Gen residual	WACMs 5, 14	Partially supported by NG 2013/14 review	Better than status quo
Generation Residual	WACMs 2, 12, 20*	Not cost-reflective, cost recovery payment	Better than status quo
Lowest locational	WACMs 6, 7, 15	No link between lowest locational in one demand zone and nationwide EG benefit	Better than status quo
Historical Levels	264†, WACMs 9*, 10, 20*, 23, (12-23†)	Not cost-reflective	Better than status quo
Cornwall Estimates	WACMs 8, 9*, 16, 17, 23*	Not locational, based on an average of projects between £4.5/kW and £241/kW	Better than status quo
Offshore costs removed	WACMs 11, 18	Not cost-reflective	Neutral
Status quo	265, Status Quo	Not cost-reflective	Neutral

*Use a combination of levels
†Grandfathered at historic level

4.63. Overall, the options which we considered likely to best facilitate this objective are those with payments to smaller EG set at the cost of avoided GSP investment. This payment recognises a benefit of smaller EG versus transmission-connected generation, and has the potential to be updated at each price control with the forward-looking benefits of EG.

CUSC Objective (c) - Facilitating charges that take account of the developments in transmission licensees' transmission businesses

General remarks

4.64. Our provisional view is that any modifications that reduce non cost reflective or distortive payments to smaller EG are likely to better facilitate this applicable CUSC objective, while any modifications that retain status quo levels of payments are unlikely to do so. Similarly, options that include grandfathering options with future cut-off dates, as discussed previously, are unlikely to better facilitate this objective. Equalisation of regimes for smaller EG and other generation recognises that all generation has a similar effect on transmission system flows. However, there is overlap with the issues covered by applicable CUSC objective (a) & (b) in the interest of avoiding double-counting, the options presented will be considered as neutral in relation to this objective.

CUSC Objective (d) - Taking account of European Legislation

General remarks

4.65. Article 14 of EU Regulation 714/2009[60] sets out that network access charges should be, among other things, cost-reflective, non-discriminatory, and should take into account investment costs. These are likely to be facilitated by any option that reduces TDR payments, in so far as TDR payments to smaller EG are currently not-cost reflective, available only to certain users and allow certain other users to avoid contributing to the costs of the network. However, these issues are covered by applicable CUSC objective (a) & (b) and must not be double counted. Due to this, the modifications could be considered as neutral in relation to this objective.

CUSC Objective (e) - Promotion of efficiency in implementation and administration of charging methodology

General remarks

[60] http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32009R0714.

4.66. Where there is different treatment of new and existing users and therefore different regimes applied to existing and new embedded generation, this is likely to lead to some additional administrative burden of an enduring nature. This may also need legacy system compatibility whenever further changes are made, meaning administrative processes and systems will need to be created to ensure the correct reconciliation of different classes for different user classes.

4.67. The below table sets out our provisional assessment of whether overall each option in front of us is better, worse or neutral at facilitating CUSC objective (e) when compared to the status quo, taking account of our assessment of the options we have considered in the round. We consider options with separation of different user classes to be less likely to further the objective of efficiency in implementation and administration.

Table 71 - Assessment of efficiency in implementation and administration

Efficiency in implementation and administration		
Level	**Examples**	**Impact on objective**
With separation of different user classes	264, 265, WACMs 12-23	Worse than Status Quo
Without separation of different user classes	Status Quo, WACMs 1-11	Neutral

Overall assessment against all CUSC Objectives

4.68. We have considered each option against all of the CUSC objectives, which is set out in appendix 7.

4.69. Of the options available, our provisional view is that WACMs 1-10 better facilitate the CUSC objectives. We also think that CMP264, and WACMs 12-17, 19 and 23 on balance better facilitate the CUSC objectives, despite their performance against objective (e) and that the grandfathering in these options introduces a new distortion between a subset of smaller EG and all other smaller EG. CMP265 and WACMs 11 & 18 are on balance neutral against the CUSC objectives. We think that WACMs 20-22 do not better facilitate the CUSC objectives.

Table 12 Assessment against CUSC Objectives

CUSC Objectives	
WACM Number	**Better facilitate CUSC objectives compared to status quo**
CMP264, WACMs 1-10, 12-17, 19, 23	Better than status quo
CMP265, WACMs 11 & 18	Neutral
WACMs 20-22	Worse than Status Quo

Compatibility with the Authority's statutory duties

4.70. In the previous section, we set out our provisional views about which options better facilitates the CUSC objectives. We now need to assess, of the options which better facilitate the CUSC objectives compared to the status quo, which are ***most compatible with the Authority's statutory duties***.

4.71. Ofgem's statutory duties[61] are centred around our principle objective, which is to carry out our functions to protect the interests of existing and future consumers in relation to electricity conveyed by distribution systems or transmission systems. This means making an overall judgement that takes into account a number of considerations.[62]

4.72. In assessing the options against the Authority's statutory duties, we have considered:

- Networks, social considerations and the environment
- Consumer costs
- Security of supply considerations

Networks, social considerations and the environment

4.73. One such consideration is the financeability and long-term stability of the regulated networks that provide benefits to their users. A continuation of the current system of net metering at the GSP, and the incentive to use smaller EG to reduce transmission system charges could see a shrinking transmission network charge payer base, and a corresponding increase in the charges for the other users. This then leads to a greater incentive to avoid charges. Options that reduce the incentives to avoid or reduce transmission charges by paying smaller EG are therefore likely to better facilitate these aims.

[61] Authority's statutory duties and general duties in relation to its regulatory functions in the electricity sector are set out in section 3A of the Electricity Act 1989 (as amended) ("the Electricity Act").
[62] There are a number of considerations that we take into account, which can be found here https://www.ofgem.gov.uk/publications-and-updates/powers-and-duties-gema

4.74. The Authority must also have regard for the impact of any changes on vulnerable consumers of any kind.[63] As vulnerable consumers may be more likely to experience fuel poverty, they may benefit more in relative terms from consumer cost reductions as such savings may be more valuable to these consumers. Options that are likely to lead to lower consumer costs are therefore preferred.

4.75. These changes may also impact efficiency and economy in the networks and in the use of electricity, as well as having environmental and sustainable development impacts. In theory, efficiently sited and dispatched smaller EG may reduce the need for network investment, whereas inefficiently sited and dispatched smaller EG could lead to increased costs. Removing distortions that contribute to the system being used in an inefficient way should lead to improved efficiency and lower costs for consumers, and so more cost-reflective payments to smaller EG payments are likely to lead to more efficient network and electricity use.

4.76. Options that lead to reduced distortions may lead to some reductions in carbon emissions, as plant will be dispatched in a more efficient manner, which is likely to favour efficient operators. Running hours for plant who operate mostly at triad to capture the TDR payment, are relatively low, and so the scope for carbon emission improvements may also be low. Grandfathering options may be, on balance, worse than those without grandfathering, as less efficient plant are likely to be dispatched when not in merit.[64]

4.77. The table below sets out our assessment of different levels of reduction in payments to smaller EG against our statutory duties in relation to network, social and environmental considerations.

Table 13 - Assessment of network, social and environmental considerations

Networks, Social Considerations and the Environment	
Level of reductions in payments to smaller EG	**Impact on statutory duties**
Larger reductions in payment	More likely to be compatible
Smaller reductions in payment	Less likely to be compatible

Consumer Costs

4.78. We believe that the current payments to smaller EG is likely to lead to out-of-merit dispatch. This may be distorting the market and is probably driving down

[63] This includes people with disabilities or the chronically sick, persons on low incomes, on those of pension age, and consumers residing in rural areas.
[64] See Appendix 5.

wholesale prices around the winter peak, so removal may lead to higher peak prices in the short term. National Grid estimates that around 7.5GW of embedded generation currently run at peak.[65] A more efficient market is likely to lead to lower costs for consumers. Therefore, our provisional view is that options that reduce TDR payments to smaller EG are likely to lead to better consumer outcomes. Balancing costs are likely to be more efficiently incurred if payments to generators are more cost-reflective[66,] and so our view is that more cost reflective payments to EG are likely to lead to lower costs overall. Our provisional view is that immediate change is likely to lead to the greatest reduction in consumer costs overall.

4.79. We expect that ancillary service[67] costs are likely to rise in the short-term under options that reduce payments to smaller EG, as plants may need to increase their charges to cover all their costs. However, in the long run, better competition through lower distortions and a level playing field should drive down ancillary service costs.

4.80. We expect that reductions in the level of payment to smaller EG may lead to smaller EG increasing their future CM bids, as higher CM revenues will be needed to cover costs that might have been previously met by TDR payments. In theory, this will see the providers submitting more cost reflective bids, which may mean higher bids from many generators, and a different group of providers when compared against the status quo counterfactual. The CM price may increase[68], though we expect consumers to save overall when the reduced TDR payments to generators are taken into account. We think that reducing payments to smaller EG will lead to lower distortions and in the long term lower costs, and more efficient investments. Therefore, options that lead to lower payments across all providers are likely to lead to better consumer outcomes.[69]

4.81. The impact of changes on investors is highly dependent on the nature of those investors, and we expect that a reduction of payments to smaller EG to improve the investment outlook for over 100MW EG[70] and transmission-connected generation, but that it may increase investment risk for existing smaller EG. Grandfathered payments are likely to welcomed by those existing investors in smaller EG who would benefit from them and may lead to reduced refinancing costs due to a perception of lower risk for this group of investors. Phased implementation

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[65] The addition of 7.5GW to the demand charging base would reduce the size of the TDR from c.47.50/GW in 2017/18 to c.£42.50/kW, by spreading the required revenue over a greater number of users.
[66] Other subsidy-driven distortions will remain.
[67] System services such as frequency response, voltage support and black start.
[68]Since receiving the FMR for decision, there have been two further rounds of the CM, both the T-4 auction in December 2016, and the T-1 early auction in January 2017. The T-4 auction cleared at £22.50/kW, compared to previous clearing prices of £19.40/kW (2014) and £18.00/kW (2015). This is not a significant increase from previous years, with around 1.5GW of small scale peaking plant clearing in the auction. The early auction in January 2017 cleared at £6.95/kW/yr. with 1.7GW of new build generation coming forward.
[69] This of course needs to be weighed against investment impacts, among other things.
[70] Like smaller EG, EG of larger than 100MW are connected to the distribution network but are currently treated as generation by the charging methodology, rather than negative demand.

may be favoured by smaller EG investors overall than immediate change, which may bring benefits to consumers by improving investor confidence. However, delays to implementing reductions in the TDR payments to smaller EG may lower the investment outlook for larger generators if they do not consider such delays to be merited.

4.82. The table below sets out our assessment of different levels of reduction in payments to smaller EG against our statutory duties in relation to consumer costs.

Table 14 - Assessment of Consumer Costs

Consumer Costs	
Level of reductions in payments to smaller EG	**Impact on statutory duties**
Larger reductions in payment	More likely to be compatible
Smaller reductions in payment	Less likely to be compatible

Security of Supply considerations

4.83. Depending on the level of ongoing revenue assumed by CM participants from TDR payments, it is possible that some generators may find options that include significant reduction challenging to their businesses, though we do not expect there to be a major impact on security of supply risk from CM non-delivery of these providers, even in the options with the most significant changes.

4.84. The T-4 and T-1 CM auctions ensure there is sufficient capacity on the system to meet the government's reliability standard. The options that propose immediate changes with no transitional arrangements are likely to lead to changes in dispatch behaviour, but is unlikely that security of supply will be significantly affected, provided market access for the affected generators is sufficient[71]. Our provisional views are that options which include grandfathering could undermine long term investment and harm security of supply by distorting investment decisions and competition. Our provisional view is that a short period of phasing to a cost-reflective payment level is likely to have the least impact on security of supply. This should create a competitive regime while minimising any immediate security of supply impacts. However, we do not think that the risks of immediate implementation are enough to rule options featuring this implementation route out on security of supply grounds.

4.85. A number of generators have indicated that they consider grandfathering of the existing payment levels to be essential to keeping their businesses viable. While we have no basis to verify this, it is possible that the implementation of options that significantly reduce payments to smaller EG and excluding grandfathering may lead

[71] Frontier /LCP's modelling suggests that the most significant proposed reduction in revenue will not lead to Security of Supply expectations outside of government parameters

to some operators leaving the market. Nonetheless, even in a worst case scenario, we do not expect market exit by smaller EG to have a major impact on security of supply.

4.86. Options that could lead to significant changes in dispatch behaviour may make forecasting of system demand more difficult, but dispatch behaviour based on market signals should lead to more efficient pricing in the longer term. Therefore, it is reasonable to expect that options with lower payments to smaller EG will lead to more difficulty forecasting. However, it should also be noted that triad periods have become increasingly difficult to predict in recent years, with levels of smaller EG a likely contributing factor, so options that lead to expansion of smaller EG may also hinder forecasting. Difficulty forecasting may lead to increased risk premiums. Phasing options may lead to lower volatility and forecasting issues, both due to the gradual nature of change and the ability to monitor the impacts.

4.87. Table 15 below sets out our assessment of different levels of reduction in payments to smaller EG against our statutory duties in relation to security of supply. Table 16 sets out our assessment of implementation options against our statutory duties in relation to security of supply.

Table 15 - Assessment of Security of Supply considerations – Payment level

Security of Supply considerations	
Level of reductions in payments to smaller EG	**Impact on statutory duties**
Larger reductions in payment	More likely to be compatible
Smaller reductions in payment	Less likely to be compatible

Table 16 - Assessment of Security of Supply considerations – Implementation

Security of Supply considerations	
Implementation	**Impact on statutory duties**
Phasing	More likely to be compatible (marginal)
Immediate	Less likely to be compatible (marginal)

Shortlisting of options

4.88. In the sections above, we have identified all the options that we consider are likely to better facilitate the CUSC objectives and are more likely to be consistent with our statutory duties. We now proceed to shortlist these options for in-depth assessment in section 7 to determine which option would best facilitate the CUSC objectives whilst also being consistent with our statutory duties under primary legislation and EU law.

4.89. Our provisional view is that, in addition to better facilitating the CUSC objectives, options that are ***most likely to best facilitate the code objectives and be consistent with our statutory duties*** will include the following characteristics:

- Recognise the avoided cost of GSP infrastructure – discussed above
- Are implemented immediately or through a phased implementation – discussed above
- Do not include grandfathering – discussed further below

Grandfathered options

4.90. We do not believe options which include grandfathering are likely to best facilitate the CUSC objectives. Although there is likely to be a relatively small increase in administrative burden through grandfathering, it is the impact on competition and cost reflectivity, when compared to the other proposals, which means these options are less likely to best facilitate the objectives.

4.91. Many options which include grandfathering do lead to better outcomes against the CUSC Objectives, they leave in place non cost reflective payments and guarantee the non-cost reflective level for extended periods for a subset of generators. Further, they provide these generators with a competitive advantage for an extended period of time.

4.92. While this is not worse than the status quo and in some cases would improve some aspects of competition compared to the status quo, it may also harm innovation, and the arrangements will also come at significant consumer cost. Grandfathering would also be likely to lead to continued out-of-merit-dispatch and less efficient plant are likely to be dispatched when not in merit. While this is not harmful for security of supply in the near-term, is likely to undermine market functioning and efficient investment leading to higher costs in the long run than would otherwise be the case.

4.93. We therefore consider that when compared with other options (such as those that provide immediate or phased implementation for all users) those options featuring grandfathering are less likely to best facilitate the CUSC objectives while being consistent with our statutory duties.

4.94. The table below sets out our provisional assessment of grandfathering in terms of which options are likely to best facilitate the CUSC objectives and our statutory duties.

Table 8 Assessment of grandfathering against code objectives and statutory duties

Grandfathering considerations against code objectives and statutory duties		
Type of grandfathering	**Examples**	**Impact on CUSC objectives and statutory duties**
No Grandfathering	265, WACMs 1-11	More likely to best facilitate
Grandfathering for CM/CfD	WACMs 12-18, 23	Less likely to best facilitate
Commissioned before a given date – near future	264, WACM 19	Less likely to best facilitate
Commissioned before a given date – further out	WACMs 20-22	Worse than status quo

4.95. The table below summarises our assessment of each option in terms of the three factors we listed above:

- Recognise the avoided cost of GSP infrastructure
- Are implemented immediately or through a phased implementation
- Do not include grandfathering

4.96. This table indicates the shortlisted options that we take forward for more detailed assessment. Those options are WACMs 3,4 and 5.

Table 18 Shortlisting Options

WACM Number	Better facilitate CUSC objectives and statutory duties	Recognises Avoided GSP costs?	Immediate or phased implementation?	Grandfathering?	Shortlisted options
264 Original	Better than status quo	No	Yes	No	Less likely to best facilitate
265 Original	Neutral	No	Yes	No	Neutral
WACM 1	Better than status quo	No	Yes	No	Less likely to best facilitate
WACM 2	Better than status quo	No	Yes	No	Less likely to best facilitate
WACM 3	Better than status quo	Yes	Yes	No	**More likely to best facilitate**
WACM 4	Better than status quo	Yes	Yes	No	**More likely to best facilitate**

WACM 5	Better than status quo	Yes	Yes	No	**More likely to best facilitate**
WACM 6	Better than status quo	No	Yes	No	Less likely to best facilitate
WACM 7	Better than status quo	No	Yes	No	Less likely to best facilitate
WACM 8	Better than status quo	No	Yes	No	Less likely to best facilitate
WACM 9	Better than status quo	No	Yes	No	Less likely to best facilitate
WACM 10	Better than status quo	No	Yes	No	Less likely to best facilitate
WACM 11	Neutral	No	Yes	No	Neutral
WACM 12	Better than status quo	No	Yes	Yes	Less likely to best facilitate
WACM 13	Better than status quo	Yes	Yes	Yes	Less likely to best facilitate
WACM 14	Better than status quo	No	Yes	Yes	Less likely to best facilitate
WACM 15	Better than status quo	No	Yes	Yes	Less likely to best facilitate
WACM 16	Better than status quo	No	Yes	Yes	Less likely to best facilitate
WACM 17	Better than status quo	No	Yes	Yes	Less likely to best facilitate
WACM 18	Neutral	No	Yes	Yes	Neutral
WACM 19	Better than status quo	No	Yes	Yes	Less likely to best facilitate
WACM 20	Worse than Status Quo	No	Yes	Yes	Worse than Status Quo
WACM 21	Worse than Status Quo	No	Yes	Yes	Worse than Status Quo
WACM 22	Worse than Status Quo	No	Yes	Yes	Worse than Status Quo
WACM 23	Better than status quo	No	Yes	Yes	Less likely to best facilitate

4.97. We therefore consider the following options to most likely best facilitate the relevant objectives and so shortlist them for closer consideration in chapter 7. The next two chapters cover distributional issues and the results of our quantitative modelling and assessment.

Table 19 CUSC Objectives and Ofgem's Statutory Duties

CUSC Objectives and Ofgem's Statutory Duties	
WACM Number	**Better facilitate CUSC objectives**
WACMs 3, 4, 5	More likely to best facilitate
264, WACMs 1, 2, 6-10, 12-17, 19, 23	Less likely to best facilitate
265, WACMs 11, 18	Neutral
WACMs 20-22	Do not better facilitate

5. Distributional Issues

Chapter Summary

This chapter describes how we have qualitatively assessed the impact of the different options presented to us on specific sectors and technologies.

Question 12: Do you agree with our assessment of the distributional issues?
Question 13: Are there any sectors that we may have overlooked?

Impacts on Specific Sectors

Discussion and assessment of wider impacts

5.1. Other sections of this document cover the potential overall impacts of these proposals on consumers and the system. This section considers specific sectors. We are mindful of the potential wider impacts of a reduction in the level of payment to smaller EG.

5.2. Ofgem have seen analysis produced during the workgroup process, produced by National Grid, that suggested that an increase in the charging base from 49.1GW to 56.6GW (an addition of 7.5GW to the demand charging base, equivalent to National Grid's estimate of the amount of smaller EG running at peak time in 2017/18) could lead to a reduction in the size of the TDR from the then forecast of c.£47.50/GW in 2017/18 to c.£42.50/kW, by spreading the required revenue over a greater number of users, a fall of 10.5%. In addition, the reduced payments by suppliers to smaller EG will reduce consumer costs.

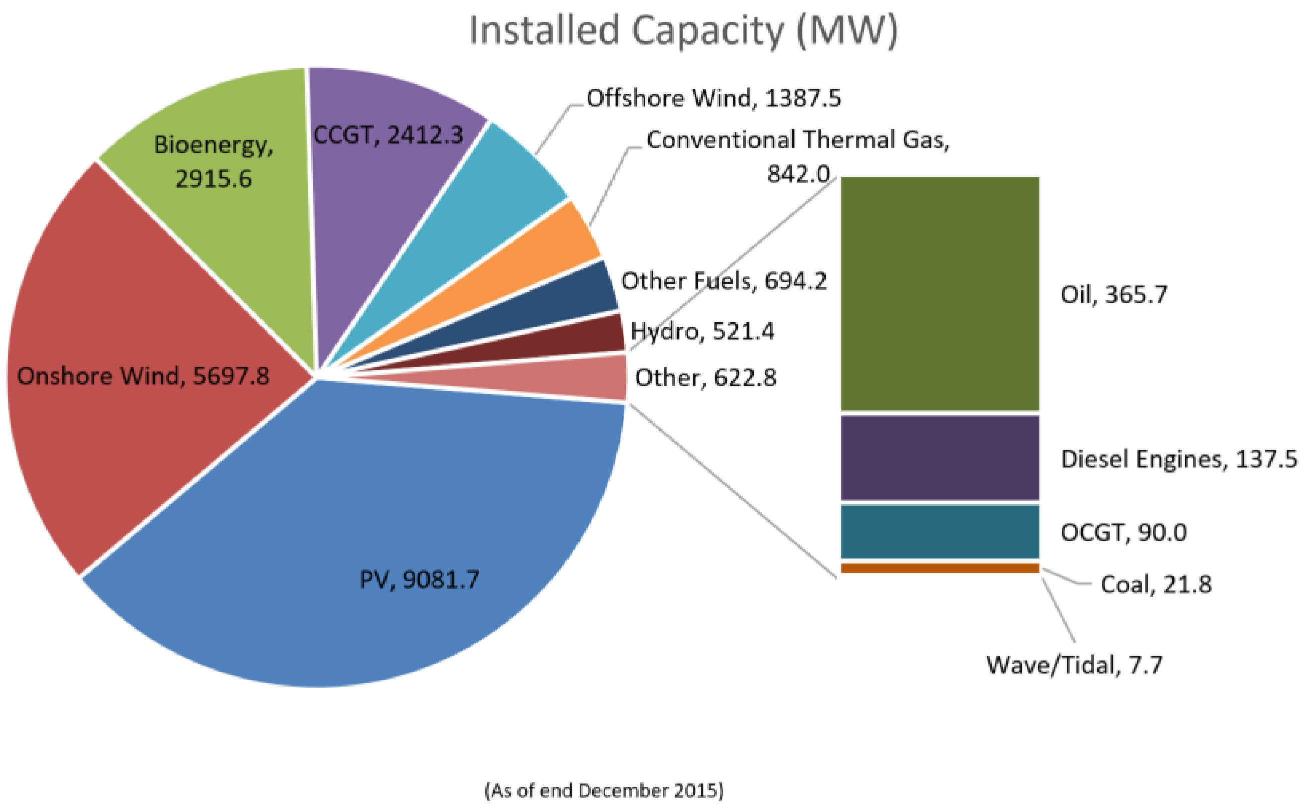


Figure 2 - Installed capacity on the distribution network

Thermal generation, CHP and EfW impacts

5.3. Generators, including energy consumers with on-site generation, are likely to see a reduction in revenues if they currently export part of their generated energy. We recognise that in some cases, this could lead to a significant challenge to business models or the perceived stranding of assets. We understand that for some thermal generators, TDR payments can form up to half of their anticipated revenues and operations are heavily geared toward hitting triad periods. We also note the potential for impacts on distribution-connected sub-100MW Combined heat and power (CHP) operators and Energy from Waste (EfW) plants. It is unlikely that embedded benefits revenues were a primary business driver for such plant. We do not expect the revenue impact on them to be as significant, with these payments forming a much lower proportion of income. We also note that many CHP and EfW plants will have been planned and constructed at times of much lower TDR payments.

5.4. We recognise that TDR payments for smaller EG CHP and EfW plant may help to support overall fixed costs. Larger EG and transmission-connected CHP and EfW plants will find a more level playing field if there is a reduction in payments to smaller EG. We understand there is in excess of 2.5GW of distribution connected

CHP, of which around half is sub-100MW (and so smaller EG), and over 4.5GW of transmission connected CHP.[72][73]

5.5. An additional concern may come from onsite generation, CHP and EfW plants that are owned by public authorities. Depending on the legal framework of the arrangements, the loss of revenue from local authority-owned generation may impose constraints on the finances of the authority. On the other hand, it is expected that a reduction in the level of payment to smaller EG will lead to consumer cost savings, and this will benefit public authorities that consume electricity, though we recognise that those with smaller EG may lose significantly more revenue than is saved in reduced bills.

5.6. It is important to point out that the use of such technologies for demand side response (DSR) will be unaffected, so those organisations that currently switch to back-up generation to avoid triad periods will still be in a position to do so, as these behaviours are not within the scope of this modification.

DSR and Storage

5.7. We do not see a reduction in the payments to smaller EG impacting behind the meter (BTM) activities (which function as a form of DSR), as they are not within the scope of this modification. We recognise that a reduction in payments to smaller EG may increase the incentive to move generation BTM to net off consumption and reduce charges. We are proposing to consider this issue as a priority area for the TCR.

5.8. Some electricity storage projects at distribution level may be reliant on the TDR payments to be economic. In theory, those options with a more immediate reduction may have a greater impact in the short term, though options with grandfathering may mean that the volatility and peak prices that storage operators aim to capture might be reduced artificially. Grandfathering would also see some existing operators offered a competitive advantage over newer, potentially more efficient or innovative operators. Similarly, where a cut-off date is applied, after which a generator cannot receive embedded benefits, all those operators commissioned before that date would be offered a competitive advantage over newer/more efficient operators including storage and DSR projects.

Renewables

[72] We understand that distribution-connected CHP is primarily utilised by the chemical, power generation and paper industries, and by public bodies. Transmission connected CHP is mainly utilised by the power and petrochemical industries.
[73] DECC figures, 2015.

5.9. We expect the impact of reduced TDR payments on renewables to be less than that of dispatchable[74] generation. For example, solar generation[75] is unlikely to receive TDR revenue under current arrangements, as generation is generally not producing in the winter early-evening periods that triad usually falls on. Wind is intermittent and non-dispatchable, with winter load factors around 30%. This means that wind generators will not be able to control whether they hit triad and therefore will not rely on TDR payments as a revenue stream. While the likelihood of receiving revenue is lower than thermal generation, we recognise that TDR payments can constitute a revenue stream for some wind operators.[76]

5.10. We estimate that there is in excess of 20GW of renewable capacity connected to the distribution network. Anaerobic Digestion (AD) plants and landfill gas plants that prioritise electricity generation over gas production may be particularly impacted, being dispatchable forms of generation. Options that reduce payments to smaller EG may reduce revenues and in some cases may prompt a switch from electricity export to the distribution networks to private wire electricity export, or to biogas production if this is more cost-effective. We also note that there are not currently well developed markets for flexibility at all levels of the networks.

Impact of potential change

5.11. In this section we provide illustrative examples of the level of embedded benefit that three smaller generators could realise, per kilowatt, according to their different generation profiles. The example is for TNUoS and BSUoS embedded benefits only, and include both the payment of TNUoS/BSUoS, and the avoided payments of both. The full table is available in appendix 4. This example does not indicate that we have reached a conclusion about whether the other embedded benefits should be changed, and these are proposed to be considered as part of the TCR.

5.12. The three generation patterns are listed below, as a percentage of their maximum capacity. Generator A and C are conventional generation, and generator B is intermittent wind generation. These illustrative examples are broadly meant to represent baseload generation (A), intermittent wind (B) and peaking smaller plant (C).

[74] Dispatchable generation is able to be turned off or on at will, and is contrasted with intermittent generation, which is not controllable.
[75] We estimate there to be around 9GW distribution connected solar.
[76] We estimate there to be upwards of 7GW distribution connected wind.

Table 20 - Levels of TNUoS and BSUoS embedded benefits for smaller EG – Illustrative generator types

	Generator A	Generator B	Generator C
Output at peak	90%	5%	90%
Load Factor across the year	90%	30%	5%

5.13. It should be noted that for these examples, it is assumed that 90% of the benefit is passed onto the generator, TNUoS is at current levels (£45.33/kW) and BSUoS is averaged at £2.40/MWh. In reality, plant chasing periods of high BSUoS levels could realise much higher BSUoS payment, up to c. £47/MWh according to the most recent settlement final BSUoS data. In addition, these take no account of the anticipated increases in CM clearing pricing or increases in peak power prices.

5.14. These are illustrative examples only, and don't necessarily reflect the actual benefits realised by any particular smaller EG. The table below shows the potential level of TNUoS and BSUoS embedded benefit that three types of generator could realise dependent on their GSP zone, in a status quo scenario (TDR of £45.33/kW) and in a scenario where the TDR is reduced to £1.62/kW. All values are in £/kW.

Table 21 - Levels of TNUoS and BSUoS embedded benefits for smaller EG

	Status quo			TDR reduced to £1.62/kW		
	Generator A	Generator B	Generator C	Generator A	Generator B	Generator C
South Scotland	**£74.88**	**£18.17**	**£39.13**	**£42.28**	**£16.36**	**£6.53**
Midlands	**£73.52**	**£14.02**	**£41.07**	**£38.11**	**£12.05**	**£5.67**
London	**£70.30**	**£8.81**	**£35.49**	**£34.89**	**£6.84**	**£0.08**

5.15. As can be seem from the example above, generators with a high load factor year round and at peak are proportionally less effected by the reduction in the TDR compared to generators which operate at peak only. Intermittent generation with a low load factor at peak are minimally affected by the reduction in the TDR.

Innovation

5.16. Our provisional view is that the network charging regime is not the correct place for supporting emerging technologies, though we are mindful of the potential investment and innovation impacts. We have not seen evidence to suggest that distribution connected generation is more innovative, but rather that network charging revenues may be pushing innovation to the distribution level. Our view is that innovation is best driven by cost reflective, non-discriminatory arrangements that support competition, and that if support is needed for technologies this should be through direct explicit subsidy to meet a policy aim, rather than through potentially distortive charging arrangements.

Overall

5.17. We consider that when considered in the round, the impacts are not disproportionate and are justified by the benefits they provide.

6. Quantitative modelling results

Chapter Summary

This chapter set out how we carried out the quantitative modelling and presents the impacts that the different options presented to us for decision.

Question 14: Do you agree with our modelling approach?
Question 15: Do you think that our background assumptions and using FES data is an appropriate approximation for status quo?
Question 16: Where WACMs are not modelled directly, do you think our assessment is appropriate (see appendix 8 for detail)?

Modelling information and assumptions

6.1. We have undertaken modelling which allows us to assess the market impacts of all the 25 proposals that are available to us. In this section we present the modelling results for the options which are likely to best facilitate the applicable CUSC objectives, our statutory duties and other distributional considerations, as discussed in the preceding chapters. The consumer and system cost savings for the other modelling results are in appendix 8. This also contains information about the model itself, the background assumptions, and information as to how we have validated the modelling results. In terms of economic values, all values are in real 2016 terms, a discount rate of 3.5% has been used, and net present values are calculated to 2034 unless otherwise stated.

6.2. Our assessment of the options presented to us has primarily been a principles-based qualitative assessment, as the GB regime should be a principles based and predictable regime with clearly set-out rules/objectives. However, in the interest of gaining insight into the likely consumers and system cost/savings and security of supply impacts of the proposed changes, quantitative analysis is needed. Ofgem has not relied on modelling outputs as the sole or predominant basis for our minded to decision.

6.3. As with any modelling, particularly of a complex nature and lengthy duration, we are conscious of the need to use caution when drawing conclusions. This modelling has been used for context of the possible impacts only. The assumptions used are conservative in nature, and so may understate the potential benefits of these changes. The uncertain nature of other elements, such as future demand, technological developments and commodity prices means that no matter what model is used, the outturn may differ from the forecast. As such, we use these results as an indication of the relative merits of the proposals, in conjunction with a principle-based assessment.

Modelling results

6.4. Due to the large number of WACMs presented to us, it was not practical to model both original modification proposals and all 23 WACMs individually. As such, we grouped the options according to (i) the level of payment/value of 'x' (ii) the presence of phasing and (iii) the presence of grandfathering.

6.5. We selected four values of 'x', in addition to the status quo, which best represented, or gave a proxy, for all of the options presented to us. It should be noted, that all values of 'x' are in addition to the inverse locational signal which all smaller EG will continue to be exposed to. The table below explains each scenario modelled. Phasing and grandfathering options were also applied to each.

Table 22 - Explanation as to how each scenario was modelled

Scenario	Value of 'x'	Explanation
Scenario 1	£45.33/kW + RPI	This is equal to the current TDR level being frozen
Scenario 2	£20.12/kW + RPI	This consists of the avoided GSP investment cost (£1.62/kW at last estimates) plus £18.50/kW, which is Cornwall's estimate based on their analysis of future transmission capital costs.
Scenario 3	£1.62/kW + RPI	Equal to the most recent estimates of the avoided GSP investment cost (£1.62/kW), as set out in National Grid's informal consultation
Generator residual	Modelled according to National Grid forecasts to 2021 then flat thereafter	Equal to the TNUoS generator residual, with the inverse sign, forecast out to 2021 and then flat thereafter.
Status quo	Modelled according to National Grid's forecasts, rising to £72/kW in 2021, then flat thereafter	The TDR increases in line with National Grid's forecast until 2021 and then remains flat thereafter.

Below we show the value of 'x' chosen for each scenario, out to 2034.

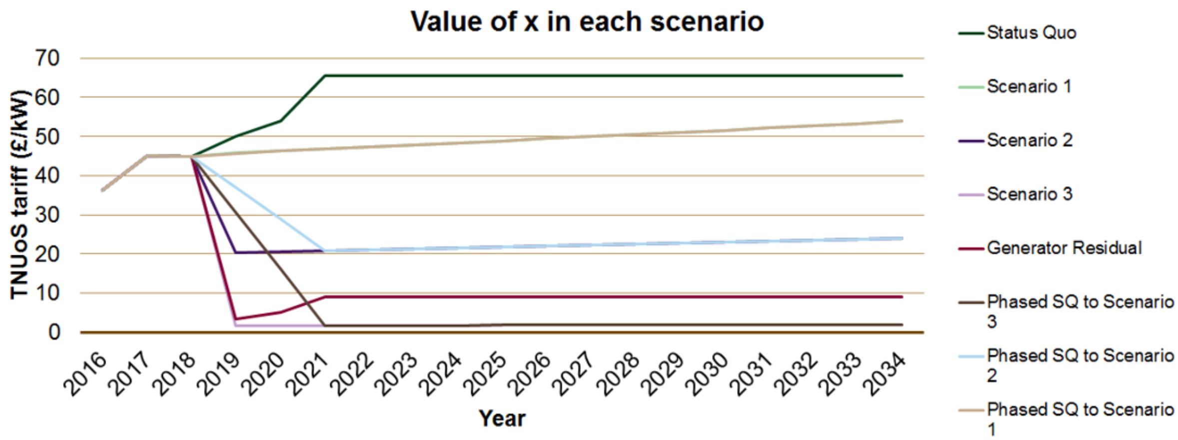


Figure 3 Value of X in each scenario

6.6. For each option, we then modelled the additional impact of phasing and grandfathering. For phasing we modelled a 3 year step down reduction in the level of payment to smaller EG, with the first step down occurring on the year of implementation and arriving at the final value of 'x' on the third year. There is a reduction in the level of payment to smaller EG of 33% each year, as per the legal drafting for the WACMs.

6.7. For each option, we also modelled the impact of adding grandfathering in two formats:

- **Option A** - Grandfathering all existing capacity which is in possession of a 2014/15 or 2015/16 Capacity Market contract or any CfD, receiving grandfathering rights at £45.33/kW; and
- **Option B** - Grandfathering all existing eligible capacity commissioned before 1st July 2017 at the rate of £45.33/kW.
- **Option C** is grandfathering both those that fall under option A and B.

Modelling results

6.8. In this section, we set out the modelling results for the shortlisted options. We then present other impacts using 'Scenario 3' as an example. The consumer and system cost savings associated with all of the scenarios and WACMs modelled, as explained above, are contained in appendix 8 including an explanation as to how we calculated the results for the WACMs not directly modelled.

6.9. As a general rule, grandfathering delivers lower benefits to consumers and higher benefits are observed in options that have lower payments to smaller EG. Phasing has a relatively small impact on consumer benefit. All options provide a benefit to consumers compared to the status quo.

6.10. The table below sets out the consumer and system cost savings for the shortlisted options. The consumer cost savings include both transfers from EG and system cost savings (and are hence not additive). These values are in real 2016 terms.

Table 23 - Consumer and system cost savings for shortlisted options

WACM Number	Modelling option	Consumer cost saving 2016- 2034 (Real, £bn)	System cost saving 2016-2034 (Real, £bn)
WACM 3	Scenario 3	7.4	2.1
WACM 4	Scenario 3 with phasing	7.2	2.1
WACM 5	Estimated between Scenario 3 with phasing and Generator residual with phasing.	7.2 - 7.4	1.8

6.11. All of the options shortlisted provide a significant consumer and system cost saving. WACM5 was estimated using the 'Generation Residual' modelling run (not including the additional value of £1.62/kW), as this has the closest value of 'x' and similar system/generator build out.

Consumer and System cost saving – shortlisted WACMs

6.12. Below you can see the annual consumer cost savings of the three shortlisted scenarios – WACM 3, 4 and 5[77]. The consumer cost savings are broadly the same for all three shortlisted scenarios, as can be seen in the table above. More information of those options that were not shortlisted, and for modelled scenarios 1 and 2 is available in appendix 8.

[77] The 'Generator Residual' modelling run has been used as a proxy for WACM5. The Generator residual modelling run does not include the avoided GSP costs but the build out is similar and the addition of the avoided GSP does not affect it significantly.

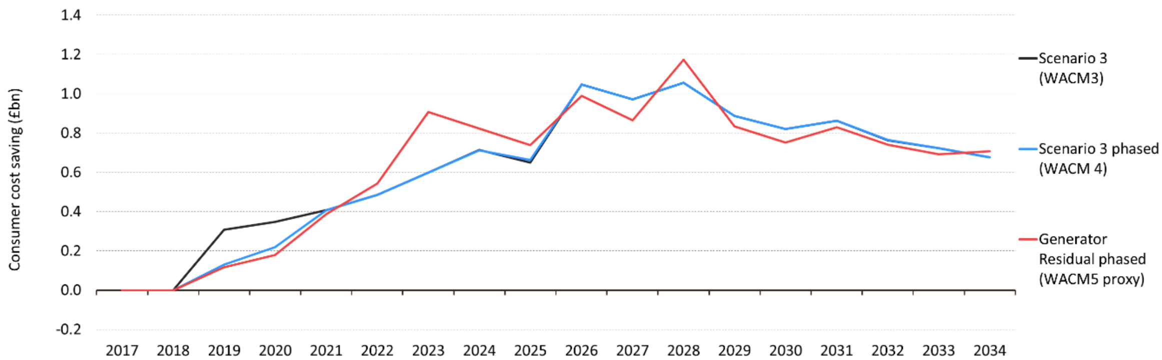


Figure 4 – Nominal Consumer cost savings of WACMs 3, 4 and 5

6.13. The majority of consumer cost savings in the scenarios above, versus status quo, is in the reduction in payments to smaller EG and the reduced wholesale cost associated with having more efficient plant on the system. After the third year of phasing, both WACM 3 and 4 follow the same profile. Below we give WACM 4 as an example of the consumer cost savings.

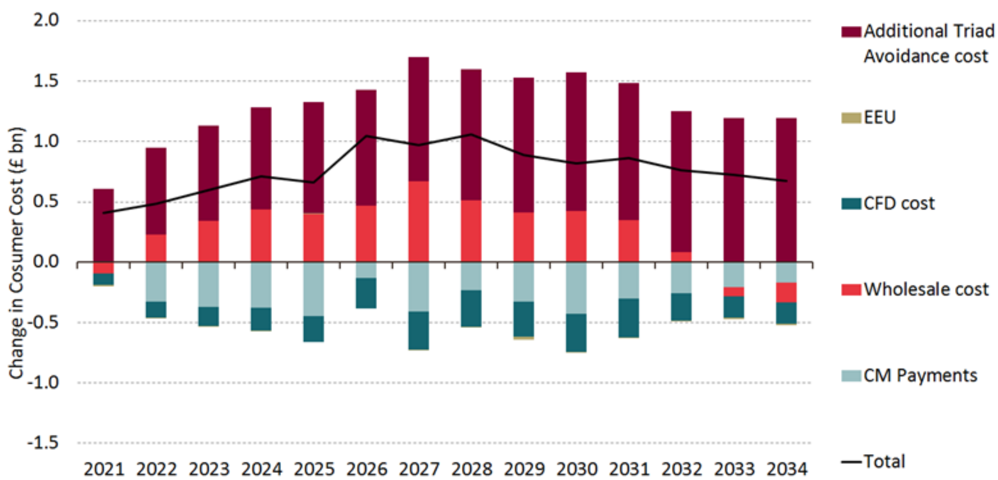


Figure 5 – Nominal consumer Cost Savings for WACM 4

6.14. The majority of savings in system cost are driven by a reduced fuel usage for power generation and some opex savings. Under the three shortlisted options, new CCGT plant come online, replacing older and less efficient existing CCGTs. This increased efficiency leads to lower system costs overall. Again, after the initial phasing period, WACM3 and 4 follow the same profile and provide the same system cost savings.

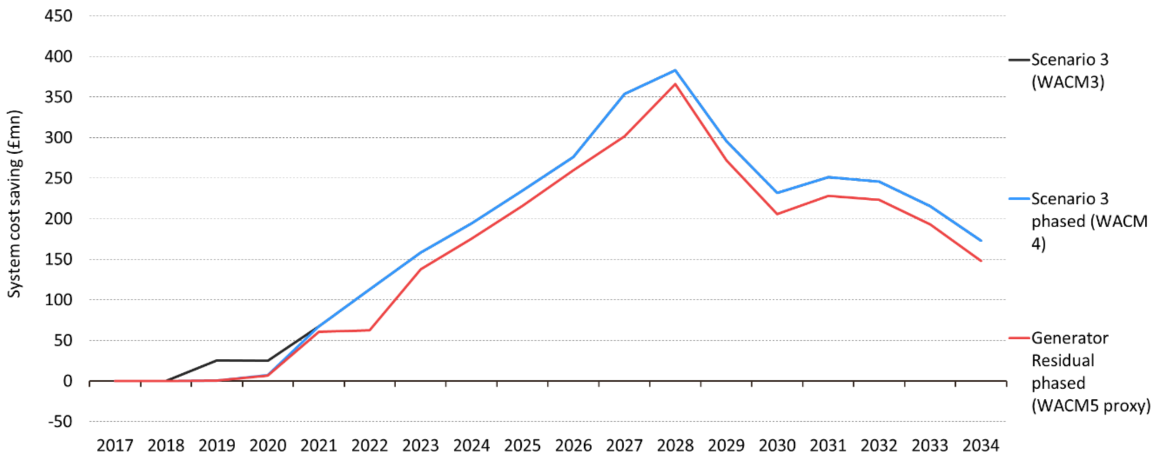


Figure 6 – Nominal system cost savings of WACMs 3, 4 and 5

Security of Supply impacts – Scenario 3

6.15. LCP assessed the impact that the most significant change to the level of payment to smaller EG (Scenario 3 not phased) would have on security of supply and on the estimated Loss of Load Expectation (LOLE). We also assessed the impact on security of supply up to 2020/21 with our own Capacity Assessment (CA) model, which gave similar results to LCP's analysis for the same time period. The modelling suggests that the impact on security of supply is limited, and estimated as being within the Governments reliability standard of 3 hours/years for all the options modelled.

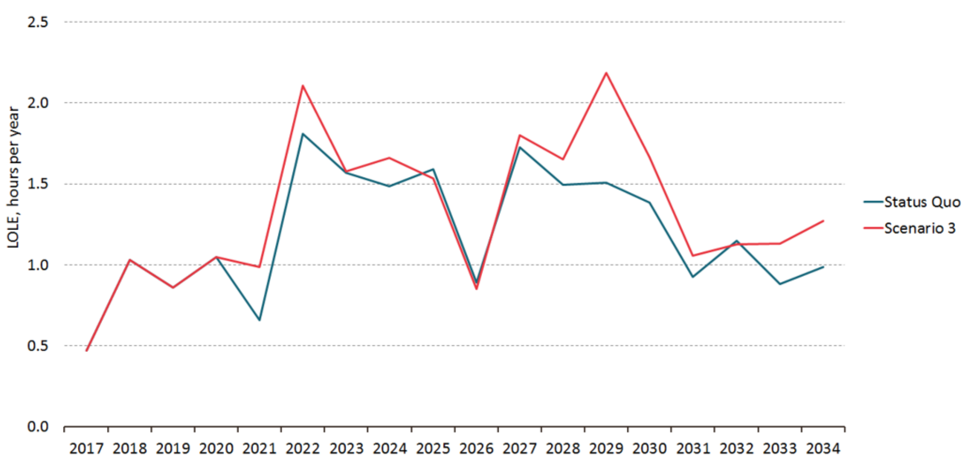


Figure 7 - Loss of Load Expectation

6.16. Our own analysis[78] shows that the next two winters are unlikely to affected by the policy changes considered, as policy change is unlikely to be implemented until 2018 at the earliest. The early delivery years of the CM (2018/19 and 2019/20) are likely to be the most impacted by the reform, due to the risk that new build reciprocating engines will not build based on these contracts. There is a risk that if some distribution-connected plant do pull out of existing CM contracts, this may take capacity out of the CM for multiple years, due to the rule that "sterilise" such capacity[79].

6.17. Overall the risk appears manageable, with the CM in later years ensuring adequate capacity is available. This may come at an increase in the CM clearing price, however, the modelling indicates that this increase would be small compared to the consumer benefits of reducing the level of TDR payments to smaller EG.

Capacity Market clearing price – shortlisted WACMs

6.18. Our modelling shows[80] that in all of the shortlisted WACMs, the CM clearing price is higher in every year compared to status quo. This is a result of the increased reciprocating engine bids (due to their reduced TDR revenues) and an increase build out of larger units. The modelling suggests, however, that the savings overall of not having to pay high levels of TDR payments, still leads to a significant consumer benefit of between £7.2-7.4bn in the shortlisted WACMs.

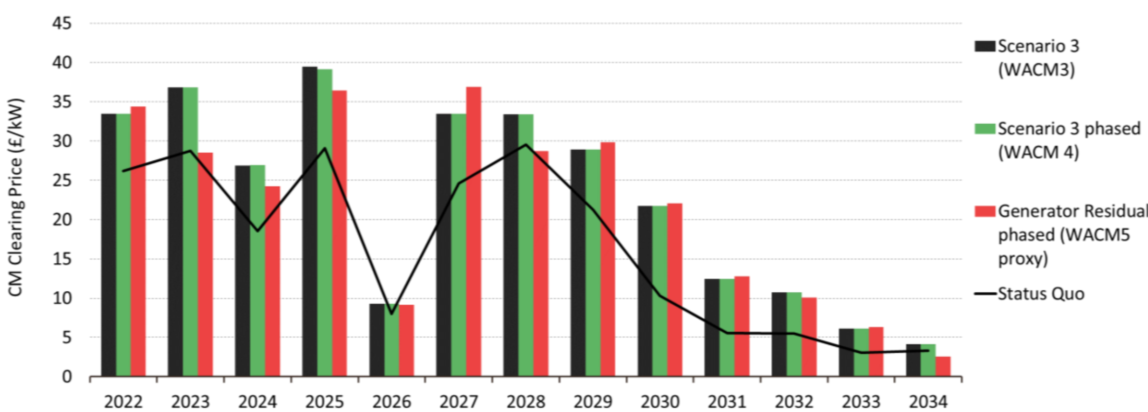


Figure 8 - Capacity Market clearing price (2022 delivery year to 2034 delivery year)

[78] Ofgem's own analysis extends to winter 2020/21.
[79] Termination fees are also payable
[80] Please note this is scenario modelling and does not represent Ofgem's forecast of future CM clearing prices

Wholesale price impact

6.19. For the illustration of the wholesale impact, the addition of phasing makes negligible difference overall, so the un-phased options are presented. The average wholesale cost decreases for both options, compared to status quo. In the modelling, this is due to greater volumes of new build larger, more efficient units winning CM contracts, with these more efficient plant setting lower peak and baseload wholesale prices.

6.20. Under the status quo, large volume of reciprocating engines come forward in the early years, dampening the wholesale price slightly in high demand periods as they chase triad for the TDR payment. This reduction in wholesale price is only short term, however, with wholesale prices under status quo increasing in later years.

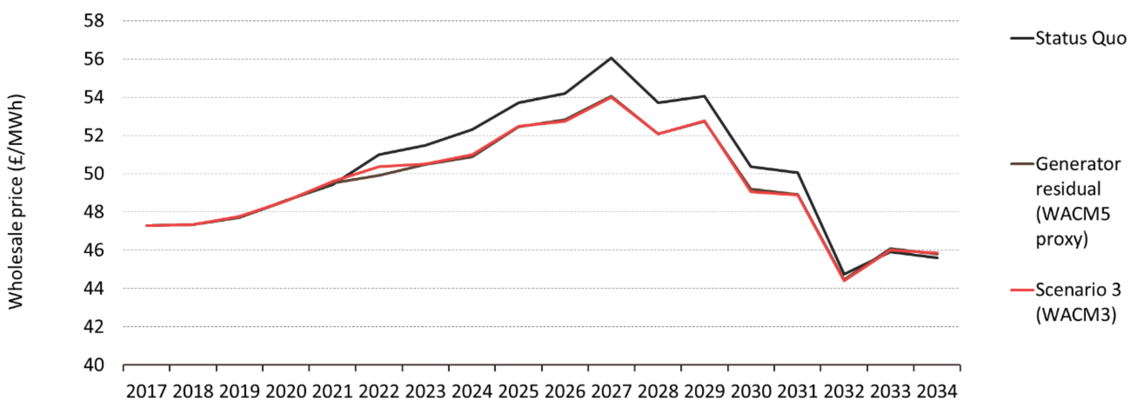


Figure 9 - Average annual wholesale prices

BSUoS charges impact

6.21. Balancing costs remain similar for the status quo, scenario 3 and the generator residual scenario until the mid-2020's, after which the balancing cost fall for both scenario 3 and the generator residual, which yield similar results. This is due to increased wind penetration in the background FES scenarios. The higher BSUoS cost in status quo is due to increased reserve cost and a larger amount of distributed capacity, decreasing the BSUoS charging base and leading to a higher BSUoS £/MWh charge. The phasing of both scenario 3 and the generator residual has little noticeable effect on the BSUoS cost so is not included below.

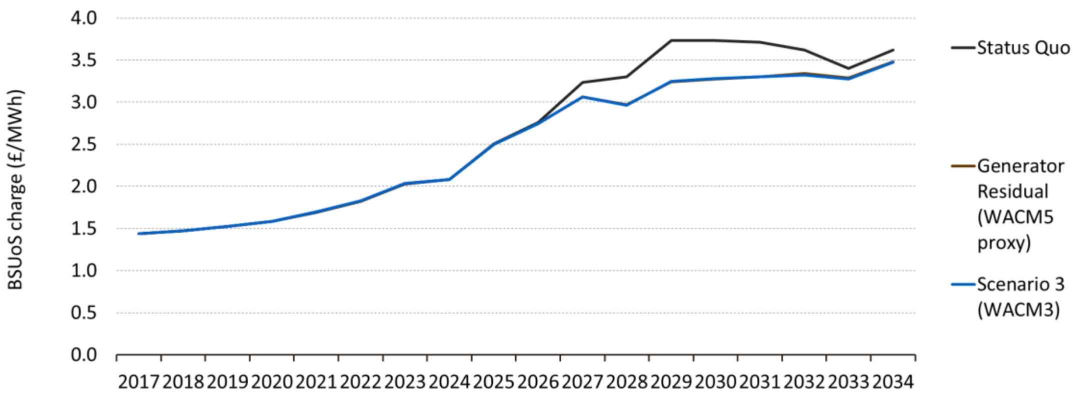


Figure 10 - BSUoS charge

CO_2 emissions impact

6.22. The total carbon emissions in scenario 3, the generator residual and status quo are mostly similar, with a small reduction in carbon emissions under scenario 3 and the generator residual due to more efficient CCGT plant coming forward in the CM. The generator residual scenario is not shown below as it follows the same trend as scenario 3. The overall downward trend is due to the increased renewable build out, and the coal closures, in the background FES scenarios.

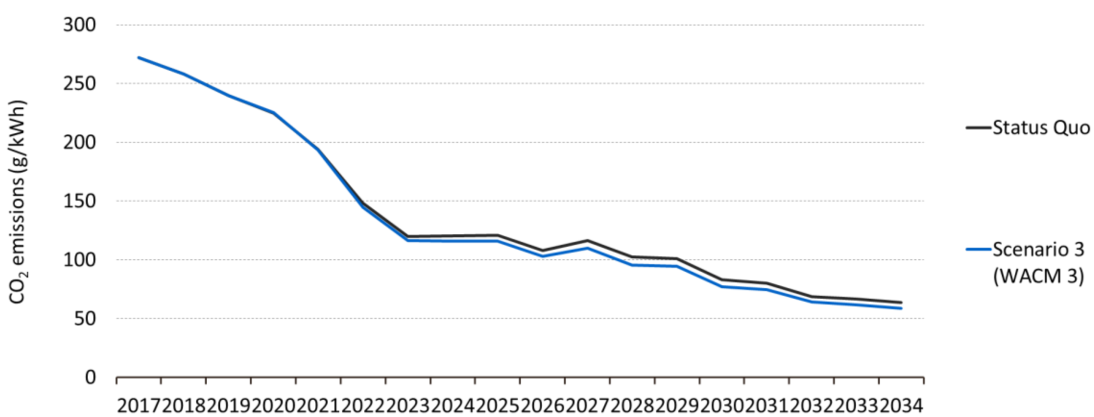


Figure 11 - Carbon Emissions

6.23. The graph below shows the CO2, compared to status quo, of the shortlisted options. Phasing was not included again, due to the effect it has being on too small a scale to see on the graph.

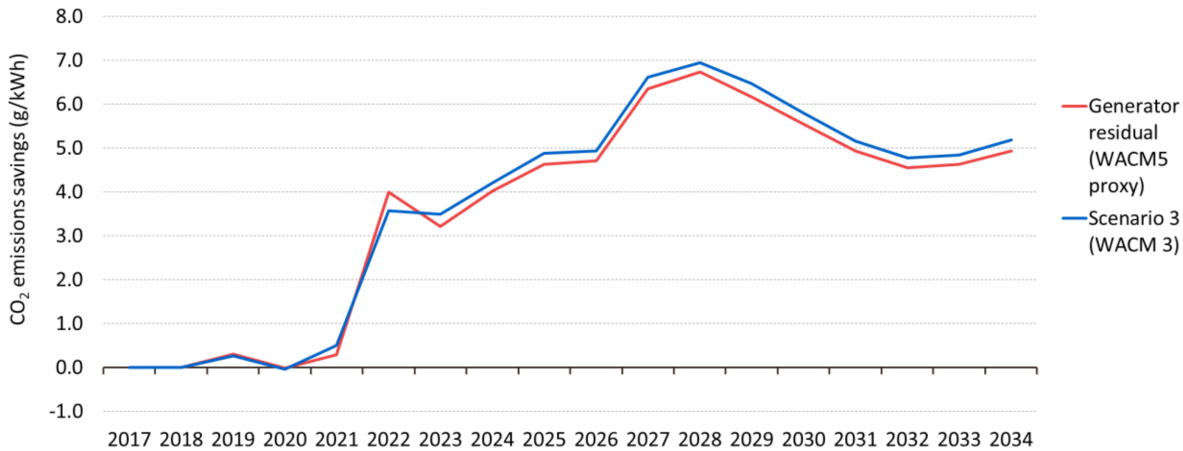


Figure 12 - Comparison of carbon savings between scenario 3 and the generator residual against status quo

7. Assessment of shortlisted options

Chapter Summary

In this section we assess the shortlisted options most likely to best facilitate the CUSC objectives and our statutory duties.

Question 17: Of the options available to us, do you agree that WACM4 best facilitates the applicable CUSC objectives?
Question 18: Do you believe that an implementation date of April 2018 best facilitates the applicable CUSC objectives?

Options available to us

7.1. The following section assess the three shortlisted options against one another and against the status quo.

Table 24 - Shortlisted options overview

WACM 3	WACM 4	WACM 5	Status Quo
WACM 3 removes net charging for all generators and stipulates that they should receive a payment of a value equal to the value of avoided GSP investment according to NG's last estimate.	WACM 4 removes net charging for all generators. New and existing generators will receive a payment of a value equal to the value of avoided GSP investment according to NG's last estimate. The change will be phased from the current level in over three years, ending up with the avoided GSP payment.	WACM 5 removes net charging for all generators. New and existing generators will receive a payment of a value equal to the value of avoided GSP investment, plus the generation residual. The change will be phased from the current level in over three years, ending up with the avoided GSP payment and generation residual.	Net charging remains. TDR increases to around £72/kW by 2020/21. Conservative modelling suggests by 2034 the cost of these payments to smaller EG could exceed £1.1bn p/a. Hours that smaller EG have to run to hit triad increases to several hundred, dispatch driven by triad not market. CM and WM distortion continues, investment in efficient plant more difficult.
Consumer savings - circa £7.4bn	**Consumer savings - circa £7.2bn**	**Consumer savings - circa £7.2-£7.4bn**	**Consumer savings - nil**
Immediate Implementation	**Phased Implementation**	**Phased Implementation**	Current Regime

Review against Connection and Use of System Code Objectives

7.2. Our assessment is that WACMs 3 and 4, with their reduction to the avoided GSP, and WACM 5 which also adds the TGR, are highly likely to lead to improvements in cost-reflectivity and competition. Our provisional work suggests there is not an economic rationale to justify the current level of TDR payments to smaller EG. Reducing these payments to an appropriate level would be more cost reflective and less distortive.

7.3. Of particular value is the fact that this avoided GSP value will be reset periodically by National Grid, allowing the payment to maintain cost-reflectivity over time. If the value of this factor is found to be higher in future, higher payments can be made to smaller EG. If the value is lower, or it is found that embedded generation is imposing costs on the transmission system, the value can be revised.

7.4. A cost-reflective variable that is updated as new information is received is preferable to a static figure that can only be changed through further code modification.

7.5. Where WACM3 offers immediate change, WACM4 and WACM5 phase the change in over three years. This will, in our opinion lead to more delayed consumer benefits and a continuation of some competitive distortion for a short period of time, but will lead to more gradual behavioural change from smaller EG and allow more time for investors to adapt. Allowing a gradual introduction of this significant change will provide time for generators to adapt their dispatch and business models, which will minimise short term security of supply pressures. During this transitional period, we are proposing to undertake the TCR which will consider the other benefits received by smaller EG alongside the wider question of how residual/cost recovery charges should be levied and other matters. The phasing options could therefore be considered the most effective compromise between consumer benefit, limited security of supply impact and investor confidence in the WACMs available to us.

7.6. We expect the current distortion toward smaller EG to continue under a "do nothing" status quo scenario, leading to much greater build-out of distributed generation. The Frontier / LCP modelling suggests that significantly more reciprocating engines would be built under the do nothing scenario than the scenarios that model the modification proposals.[81]

[81] It is not suggested that an increase in reciprocating plant is a problem in itself. Instead, we note that this is indicative of a greater number of smaller distribution-connected plant. While it is not always the case, these plants are generally less-efficient, with higher fuel costs (this is the case for diesel reciprocating engines in particular). This result may indicate a distortion in building incentives toward smaller EG embedded plant, even where this is not the naturally efficient plant size or connection level.

7.7. A retention of the status quo is likely to lead to an increase in the number of hours that a distribution-connected plant is required to run to capture the triad benefit.[82] In contrast, we expect there will also be a significant reduction in the incentive for EG to generate out of merit to hit triad under WACMs 3,4 and 5. This will lead to plants running in merit based on their marginal cost of generation, rather than on a need to hit triad. This should bring more efficient plant in earlier and prevent expensive generation running while more efficient plant sits idle.

7.8. As well as reducing payments to smaller EG, the costs of which are borne by consumers, WACM3, 4 and 5 result in a significant reduction in system costs, predominantly from fuel savings, but also from reduced emission costs. The "do nothing" option is likely to lead to continued increases in consumer costs, as well as significant increases in system costs, predominantly from fuel costs.

System costs savings under WACM3 compared to status quo

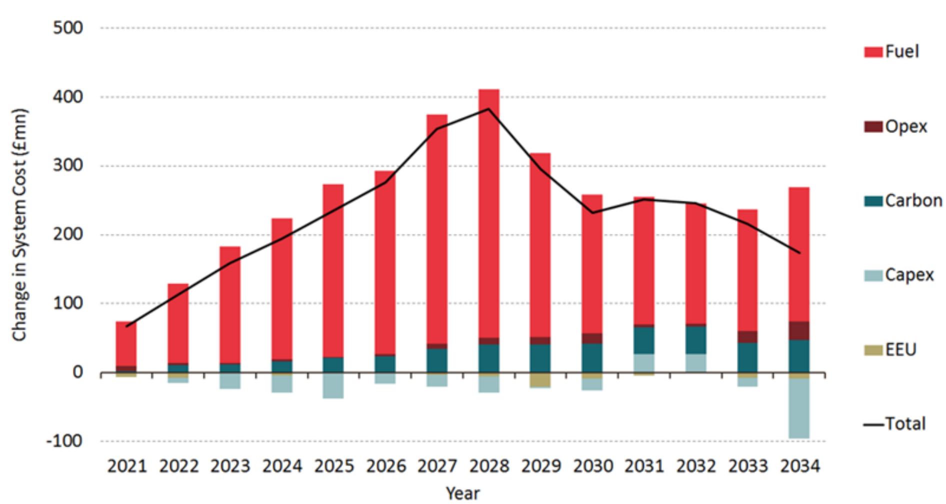


Figure 13 System costs savings under WACM3 compared to status quo

7.9. We think that the "do nothing" option is likely to be harmful for competition. The TDR is forecast to increase to £72/kW, meaning a significant revenue stream will be available to smaller EG that is not available to larger EG or to TG. Under WACM 3 and 4, we believe competition between embedded and transmission connected generation is likely to be much improved, as there will be a greatly reduced incentive to direct investment at the distribution level.

[82] There is a natural limit, where the number of hours running erodes the financial incentive to run for triad as the number of hours needed increases.

7.10. WACM 5 will possibly bring greater competition benefits if the TGR is negative, due to a reduced possibility of additional revenue for larger EG and TG, but may be worse when the TGR is positive. We believe the specific approach outlined in the proposals may not be fully consistent with maximising competition. Smaller EG will benefit from this charge if it turns negative, but will not be fully exposed to this charge when it is positive, due to the Floor at Zero mechanism that prevents smaller EG paying to generate at peak.

7.11. This means that on balance smaller EG are unlikely to contribute to network costs to the same extent as larger generators when the TGR is positive, but will get the full benefit when the TGR is negative. We have some concerns about the inclusion of the TGR, as the future level of the TGR is difficult to predict.

7.12. If the TGR goes negative, WACMs 3 and 4 could give larger generators access to around £3/kW in early years, rising to around £9/kW in 2020/21, that smaller EG cannot access. However, we have previously communicated our concern with a situation where the generation residual turns negative. One driver for this is the current €2.50 cap on generator use of system charges. If this was to be revised, or Ofgem was to consider a different method of recovering the residual costs of the network from generation as part of its Targeted Charging Review, the size or existence of a negative generation residual might differ from today's forecast.

7.13. Additional revenue under the status quo scenario is likely to lead to lower smaller EG bids in the CM, distorting build-out away from plant that cannot access this payment. Under WACMs 3, 4 and 5, CM bids are likely to be more cost reflective, though WACMs 4 and 5 will take longer to reach this cost reflectivity due to phasing. More cost-reflective bids are likely to lead to more efficient plant sizing and investment.

7.14. The retention of the non-cost reflective TDR payment is not well justified. The payment of the TDR, a charge used to recover the costs of the network not recovered from the locational charges, is not cost-reflective and has no justification in revenue recovery. Revenue recovery should be carried out in a non-distortive manner. WACMs 3,4 and 5 all recognise smaller EGs potential benefits in the form of avoided GSP reinforcement costs, supported by evidence from National Grid and others.

Impacts on Consumers, Investment and Markets:

7.15. Under WACMs 3, 4 and 5, we expect there to be some near term cost increases in some areas for consumers in the wholesale and Capacity Markets as winter peak power moves to a more merit-order driven dispatch, rather than elements being triad-driven. These effects are likely to be far outweighed by the reduction in costs driven by the need for suppliers to pay smaller EG. In the long term, a more competitive market that is more supportive of innovation is likely to lead to consumer benefit. On the other hand, we expect that the "do nothing" option, where the status quo is retained, is likely to lead to suppressed peak wholesale prices, which may lead to lower consumer costs in the short term, but less investment in efficient plant in the long term.

System costs savings under WACM3 compared to status quo

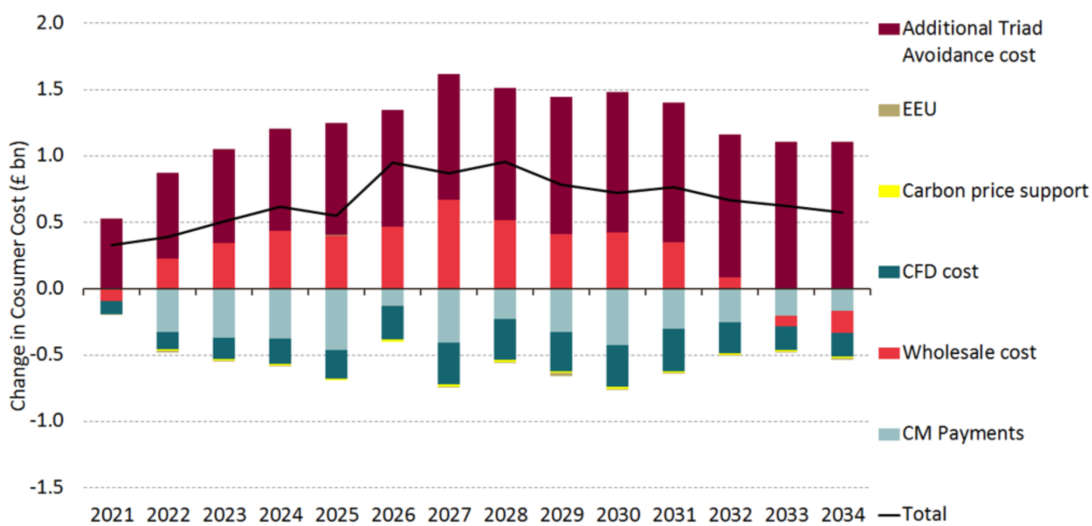


Figure 14 System costs savings under WACM3 compared to status quo

7.16. Overall, as supported by the results of our modelling, we expect WACMs 3,4 and 5 to bring significant cost savings.[83]

7.17. We expect WACMs 3, 4 and 5 to have a significant impact on some existing embedded generation investment. Where the continued payment of the TDR was factored into investments, its removal may cause shortfalls or drops in rates of return. The impact may be lessened slightly through WACMs 4 and 5, which provides a continuing, though reducing revenue stream to smaller EG for a short period. Industry participants and energy consumers that have made investment decisions

[83] We would again note that this modelling has been used for context and to help us understand the possible impacts of the proposals, and that it has not formed the sole basis of our decisions. We do expect it to be provide a good indication of the relative merits of the proposals and to provide some indication of costs and benefits to customers.

that assumed continued payments from the network charging system may find that those investments are uneconomic without them.

Overview of Final Options

Table 25 Overview of Final Options

Option	Value of 'x'	Implementation	Grandfathering	Assessment	NPV to 2034
Status Quo - do nothing	Rises to £72 in 2020/21	N/A	No	**Competition** - Harmful. £72/kW available to sub-100MW EG in 2020/21 and not TG. **Cost reflectivity** - Not cost reflective as an EB, no methodology for determining 'x'. Dispatch driven by Triad. **Consumers** - High consumer cost, distorts innovation and dispatch - damaging to consumers.	0
WACM 3	Avoided GSP cost (£1.62/kW)	Immediate	No	**Competition** - Improved between TG/Sub-100MW EG and EG/Sub-100MW EG . Removes the siting and merit running distortions immediately. **Cost reflectivity** - Transparent and cost reflective methodology in the CUSC, using price control data. Based on previous National Grid work. **Consumers** - Immediate change ensures the greatest consumer cost saving but may happen too fast for investors	Consumer cost saving £7.4bn System cost saving £2.1bn
WACM 4	Avoided GSP cost (£1.62/kW)	Phased	No	**Competition** - Improved competition between TG/Sub-100MW EG and EG/Sub-100MW EG. Removes the siting and merit running distortions. **Cost reflectivity -** Transparent and cost reflective methodology in the CUSC, using price control data. Based on previous National Grid work. **Consumers** - Phasing delays consumer benefit and has small cost. Phasing avoids negative impacts for security of supply.	Consumer cost saving £7.2bn System cost saving £2.1bn
WACM 5	Avoided GSP cost (£1.62/kW) PLUS generation residual	Phased	No	**Competition -** Improved competition between TG/Sub-100MW EG and EG/Sub-100MW EG. Removes the siting and running distortions. Generation residual improves compeition between TG/Sub-100MW EG. **Cost reflectivity -** Transparent and cost reflective methodology in the CUSC, using price control data. Generator residual element not justified by cost-reflectivity - could be volatile and unpredictable as generator residual only forcasted to 2021. **Consumers -** Phasing delays consumer benefit and has small cost. Phasing avoids negative impacts for security of supply. Generator residual level not forecasted past 2021 meaning option may be unpredictable.	Estimated to be: Consumer cost saving £7.2-7.4bn System cost saving £1.8bn

Review of Distributional Impacts

7.19. We expect that a reduction in the TDR to the avoided GSP cost to lead to reduced revenues for smaller EG, including for embedded CHP. Storage at embedded level will receive reduced revenues, which may increase ancillary service costs for FFR and EFR. Most renewables are unlikely to have included these embedded benefits in their business plans, due to their intermittency. WACM 5 will also offer slightly more revenue in situations where the TGR is negative. In contrast, the "do nothing" option, where the status quo is retained, would lead to increased revenues for these operators, at the expense of other consumers.

7.20. A reduction in payments to smaller EG and the resultant increase in charging base will lead to reduced costs, both overall and on a per unit basis, for demand consumers. We expect a small, but noticeable fall in the size of the TDR, which will benefit all demand users and will reduce electricity costs for many businesses.

7.21. Ofgem have reviewed analysis produced during the workgroup process, produced by National Grid, that suggested that an increase in the charging base from 49.1GW to 56.6GW (an addition of 7.5GW to the demand charging base) could lead to a reduction in the size of the TDR from the (then) forecast of c.£47.50/GW in 2017/18 to c.£42.50/kW, by spreading the required revenue over a greater number of users, a fall of 10.5%.

Risks, interactions and unintended consequences

7.22. As discussed earlier, we do not consider that WACMs 3, 4 or 5 will have a material impact on security of supply, though note that a gradual transition through WACM 4 or 5 may be more desirable and allow for less immediate generator behavioural change, albeit at some consumer cost. Under a status quo option, near-term security of supply is unlikely to be harmed, but there is a significant price risk, as the cost of generation is higher. Longer-term, securing efficient plant may be increasingly difficult.

7.23. We do not consider WACM 3 to have a material impact on security of supply considerations. However, we recognise that compared to an immediate change, phasing options may lead to less volatility as dispatch behaviour will change more gradually, rather than the change occurring in one year. It is therefore likely to be easier to monitor and predict. This is desirable, and when combined with the additional security for investors and the relatively low costs[84], a phased option seems well justified. This additional period may assist operators in finding replacement revenue streams.

7.24. We recognise that the withdrawal of the bulk of TDR revenue under WACMs 3, 4 and 5 may lead to an incentive for generators currently used for export to reconfigure as back-up generation for Demand Side Response or private wire supply.

[84] We estimate the cost to be around £250mn, which although large, is only a small percentage of the consumer savings that will potentially be delivered.

In practice, this may not materialise quickly due to the investment and permissions required. This will be avoided with the retention of the status quo, though grid defection risk for demand users could be higher if the costs of continued payments to smaller EG drives up demand charges and decreases the charging base.

7.25. WACM 3, which brings about immediate change, may lead to some reduction in investor confidence. WACMs 4 and 5 may do this to a lesser degree due to phasing. We do think that that, on balance, a reduction in embedded benefits in the present circumstances should be foreseeable to prudent investor familiar with the Ofgem statutory objectives and the CUSC code objectives. In contrast, there is a risk the retention of the status quo option could lead to more investor uncertainty. Having made evidenced statements that we think the payments are distortive, doing nothing is likely to be seen as inconsistent.

7.26. There have been suggestions that change to the current regime will bring about increases in borrowing costs, which could outweigh the benefits of change. We expect that any increase in the cost-of-capital for smaller generation would be outweighed, not just by the consumer benefits, but by the improvement in competition. Larger generation will find itself in an improved operating environment, and without grandfathering, new smaller EG will compete with existing operators on a level playing field.

Transitional Arrangements and Implementation options

7.27. Implementation that occurs sooner is likely to lead to more immediate consumer benefit, but later implementation will increase the notice period for suppliers and investors.

7.28. The phasing and grandfathering options available to Ofgem are fixed methodologies, as set out by the legal text for each of the CUSC proposals/WACMs, so no additional forms of grandfathering or transitional arrangements can be proposed, nor do we think they are justified.

7.29. Ofgem do, however, have the ability to set the implementation date. As such, a later implementation date can be set in combination with the available CUSC proposals/WACMs. Below we assess the arguments for and against the different implementation dates or transitional arrangements available to us. The 'Normal' implementation would be the change being implemented in April 2018 for the April 2018/19 triad period, using Scenario 3. The delayed implementation assumes following a status quo scenario for 1 or 2 years before implementation and therefore reflects the additional cost of allowing the TDR to rise.

Table 26 - Cost of implementation options

Implementation	Cost (£m)
Normal	0.00
Delayed implementation 1yr	338.6
Delayed implementation 2yr	695.1
Phasing to avoided GSP	251.00
Grandfathering at £45.33	847.00

Assessment of implementation options

Table 27 - Assessment of implementation options (including grandfathering option for comparison)

For each		**Immediate change in 2018 WACM3**	**Phased Implementation over 3 years WACM4**	**Grandfathering CM/CfD at £45.33 WACM13**
	Cost (£m)	0.0	251.0	847.0
	WACM meets CUSC and Stat Duties?	Yes	Yes	Yes
Consumers		Least cost	Moderate cost	Higher consumer cost due to grandfathering (15 years @ £45.33/kW)
Impact on investors	*CM EG*	Rapid regulatory change and reduction in revenues	Some additional revenue and time to adapt	Additional revenue Regulated nature Improves investor confidence
	non-CM EG	Rapid regulatory change and reduction in revenues Better Non-CM EG competition with CM EG	Some additional revenue No competitive disadvantage against CM EG	Non-CM EG have to compete with rivals with different revenue stream
	New EG	Rapid regulatory change. Better New EG competition with existing EG.	Some additional revenue No competitive disadvantage against CM EG	New EG have to compete with rivals with different revenue stream
	TG	Rapid removal of disadvantage	Phased removal of disadvantage	TG have to compete with rivals with large different revenue stream
Competition	*between TG and CM EG*	Distortion removed immediately	Distortion phased out quickly	Grandfathering improves competition Large distortion remains CM EG advantage locked in for 15 years
	TG vs smaller EG	Distortion removed immediately	Distortion phased out quickly	Distortion removed immediately
	Innovation	Innovation enhances competitiveness	Innovation enhances competitiveness	Grandfathered payments for some users mean innovation may not translate to enhanced competitiveness
Cost reflectivity		Cost-reflectivity achieved immediately	Cost-reflectivity achieved quickly	Poor - cost-reflectivity not reached by certain parties
SoS		Peak running for Triad could stop sharply	Phased removal means peak running does not stop sharply	Existing Sub-100MW EG peak running does not change
System Complexity				Complex parallel systems running
Impact on different technologies	*Larger generators*	May improve competitiveness	May improve competitiveness	Have to compete with rivals with large different revenue stream
	Sub-100MW EG EfW	Reduce revenues	Reduced revenues post transition	Safeguarded revenues
	Sub-100MW EG Renewables	Reduce revenues	Reduced revenues	Safeguarded revenues
	Sub-100MW EG AD	Reduce revenues	Reduced revenues post transition	Safeguarded revenues
	Sub-100MW EG CHP	Reduce revenues	Reduced revenues post transition	Safeguarded revenues

Review against Statutory Duties

7.30. We are minded to direct the adoption and implementation of WACM4.

7.31. Our view of the options put to us is that we expect WACM 4 to be in the best interest of customers. We think that its use of a phased implementation means, on balance, it is more suitable than WACM 3, and we think that the limitations of the proposed use of the TGR means WACM 5 may not be the best option. We believe WACM 4 better balances the interests of customers and investors, and provides greater reassurance on security of supply (though we would stress that WACMs 3 and 5 are unlikely to pose a risk to security of supply). We do not believe the retention of the status quo option is in the interests of consumers due to the potential for significant increases in consumer costs in the long term.

7.32. Any decision on transitional arrangements, in the form of phased transitions or otherwise, will be made independently and there should be not read-across to other modifications, nor should this be seen to establish a precedent. Instead, our provisional view is that phased change is appropriate in this case.

Table 28- Overall assessment

CUSC Objectives and Ofgem's Statutory Duties	
WACM Number	**Better facilitate CUSC objectives**
WACM 4	Best Facilitates
WACMs 3, 5	Likely to better facilitate
264, WACMs 1, 2, 6-10, 12-17, 19, 23	Less likely to best facilitate
265, WACMs 11, 18	Neutral
WACMs 20-22	Do not better facilitate

Assessment of options against status quo

Table 29 Assessment of options against status quo (including grandfathering option for comparison)

Value of "x"	Shortlisted	Description	NPV (£bn)	Arguments why better than status quo	Arguments why worse than status quo	Facilitating Competition	Cost-Reflective Charging	Charges that take account of developments	Taking account of EU Legislation	Efficiency in imp. and admin.	Likely to better facilitate CUSC?	Likely to best facilitate CUSC?
Avoided GSP costs (Currently £1.62) (WACM3)	Yes	• Moves to charging TNUoS Demand Residual (TDR) on half-hourly metered gross demand • Pays EG "the cost of avoided GSP infrastructure investment" • Avoided GSP costs calculated at the beginning of each price control period.	**7.4**	• Avoided GSP costs are most cost reflective option per NG evidence, though still has limitations as is a non-locational average and doesnt account for exporting GSPs •Payment for these saved costs ensures TG & EG compete equally, allowing efficient competition. •Legal text concept, rather than value, means level can be updated later •Dispatch moves to merit-order driven rather than Triad-driven	•TG may receive additional revenue through gen residual while EG don't (can be addressed through TCR)	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	YES	YES
Avoided GSP costs (Currently £1.62) (Phased) (WACM4)	Yes	•As with WACM3, pays EG "the cost of avoided GSP infrastructure investment" •Implementation phased over 3 years, with current payment level reduced by one-third each year, ending with final payment level.	**7.2**	• Avoided GSP costs are most cost reflective option per NG evidence • Phased transition to new regime prevents "cliff-edge" change •Payment for these saved costs ensures TG & EG compete equally, allowing efficient competition. •Legal text concept, rather than value, means level can be updated later •Dispatch moves to merit-order driven rather than Triad-driven, but through more gradual change over three years •Phased transition means behaviour change less sudden, which may improve forecasting and security of supply and provide some additional revenues to allow existing generators to adapt	•TG may receive additional revenue through gen residual while EG don't (can be addressed through TCR)	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	YES	YES
Avoided GSP (Currently £1.62) + Generation residual (predicted to reach c.£9/kW by 2021) (Phased) (WACM5)	Yes	•As with WACM4, but also exposes EG to the gen residual. Positive charge reduced locational payments (but floored at zero), negative charge adds to locational payments •Implementation phased over 3 years as in WACM4	**7.2-7.4**	•Avoided GSP and phasing as per WACM4 •Addition of Generation Residual better aligns EG to TG, but floor at zero means EG and TG will still have slightly different arrangemets and dispatch incentives. •Gen residual EB may be better addressed via TCR.	•Generation residual likely to change (potentially a lot) as linked to charging methodology meaning further distortion could arise from "floor at zero". •Consistency - is charging residual to EG but not locational charges appropriate. •"Floor at zero" means EG, on balance, will pay less than TG	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	YES	YES
Avoided GSP (Currently £1.62) plus £45.33 Grandfathering for CM/CfD (WACM13)	No (shown for comparison)	•As with WACM3, but existing CM and CfD sub-100MW EG continue to receive paymenrs based on based on the 2016/17 TDR level •Implementation immediate for new EG	**6.6**	•As per WACM3, plus additional certainty for existing CM/CfD investors, though at significant consumer cost •Allows TG & other EG compete equally, allowing efficient competition.	•Lower consumer benefit than options without grandfathering •Cost reflectivity of grandfathered level not well justified •Large EB maintained for some existing generators meaning significant competitive advantage conferred. •Out-of-Merit dispatch incentives remain for CM EG •Additional administration as separate user categories	Better than status quo	Better than status quo	Neutral	Neutral	Worse than status quo	YES	NO

8. Conclusion – Minded to position

Chapter Summary

Here we set out our provisional view that WACM 4 best facilitates the CUSC objectives and our statutory duties.

Minded to Decision

Our provisional view is that WACM 4 best facilitates the CUSC objectives and our statutory duties

8.1. Our minded to decision is to direct that WACM 4 be made. The level of payment to smaller EG should be reduced to the avoided GSP costs, and that we believe a phased approach over three years to this would be justifiable. We think that this represents a robust, evidence based solution and best facilitates the CUSC objectives and our statutory duties, and offers the best balance of benefits and costs to consumers and investors. It will allow industry to react to the changes and provide a transmission period to the final cost reflective value of 'x'. During this transitional period, we are proposing to undertake the Targeted Charging Review which will consider the other benefits received by smaller EG alongside the wider question of how residual/cost recovery charges should be levied and other matters.

8.2. While we do not foresee any security of supply issues from an immediate change, the phasing option may lead to less volatility as dispatch behaviour will change more gradually, rather than the change occurring in one year. This is desirable, and when combined with the additional security for investors and the relatively low costs, this option seems well justified.

Implementation

8.3. We believe the most appropriate implementation route is a phased implementation over three years starting from the next charging year, and we do not believe any further delayed implementation is required in addition to phasing.

Appendices

Index

Appendix 1 – Components of the TNUoS charge

In this appendix we provide an overview of the Transmission Network Use of System (TNUoS) charge for demand, with the intention to provide a background to the TDR payment which smaller EG can receive.

TNUoS charges are intended to cover the cost of installing, operating and maintaining the transmission network, with part being recovered from generation and part from demand. In this section we will focus only on the demand TNUoS, which is recovered from suppliers. The TNUoS demand charge is made up of two components, the locational charge and the residual charge. These are explained in more detail below. The TNUoS demand charge is currently levied based on triad demand – that is the net demand averaged across the three settlement periods of highest transmission system demand, between November and February, with each settlement period separated by at least 10 days.

Locational Charge

The locational charge estimates the incremental transmission cost resulting from connections to the transmission network according to where generation or demand is located in GB. Charges are averaged across the 14 demand zones).

The locational charge is intended to be a forward looking incremental cost signal. It shows the difference in cost of locating, and using the network, in different demand zones within GB. As such, it can be argued that embedded generation can help avoid some of these incremental investment cost, to the extent that they could help reduce flows on the transmission network.

Residual Charge

The locational component does not recover the full revenue allowed by the transmission owners in their price controls. This is because there is no reason that the forward looking incremental costs of transmission investment should equate to the average costs of past investment, which National Grid recovers through their price control. Therefore, to ensure that the correct revenue is recovered, a non-locational 'residual' tariff element is included. Networks often have high fixed costs, and relatively low proportions of costs that vary with use.

The second component of the demand TNUoS tariff is the residual component, or TNUoS Demand Residual. This is a cost recovery element which ensures that the total allowed revenue is recovered by National Grid. The majority of the residual charge is historic costs of the network, i.e. those costs that are already spent or cannot be saved by demand user behaviour. Currently the residual component of the charge is £45.33/kW for all demand users, irrespective of their location in the country.

Treatment of smaller EG

Generation over 100MW on the distribution network pays TNUoS generation charges, as does transmission-connected generation. Smaller EG is currently treated as 'negative demand' for transmission charging purposes. The output from smaller EG during the triad period is deducted from a supplier's gross demand, in order to calculate their net demand, on which they are billed. As such, smaller EG can help a supplier to reduce their TNUoS bill liability.

Smaller EG being treated as negative demand for the locational (forward looking incremental) portion of charges broadly reflects the potential contribution that EG can provide to the electricity transmission system, and is the reason that it was included as a continued locational signal for smaller EG in the WACMs presented to us (i.e. it remains net, not moving to gross). It should be noted that smaller EG can still impact flows on the transmission system, and in some areas the amount of smaller EG means power is exported from the distribution system onto the transmission system, which may be increasing network costs.

Some network costs cannot be reduced by embedded generation, however that generation it is used. In particular, the ability to use embedded generation to avoid paying the TDR charges (the cost recovery element), and for smaller EG to be paid to help suppliers avoid it, represents a major distortion. Because the Transmission Operators have a fixed allowed revenue, where the TDR charges are avoided, it means someone else has to pick up these costs and pay more than they otherwise would. Due to the fact that the TDR largely recover the historic costs of the network, as well as fixed costs, these costs cannot be avoided with a change of network use.

Appendix 2 – History of Embedded Benefits and the TDR payment

This section provides a high-level summary of the history of embedded benefits, as well as a high level explanation as to why the TDR payment to smaller EG has increased.

History of Embedded Benefits

We have had concerns about the transmission charging arrangements for smaller EG for a number of years[85]. The payment to smaller EG comes about due to difference in treatment of these generators and their location on the distribution system, as explained in Appendix 1. Initially, embedded benefit issues were raised during the development of BETTA (British Electricity Trading Transmission Arrangements). This created a single electricity market covering England, Wales and Scotland with implementation in 2005.

Several attempts to develop enduring charging arrangements for EG were postponed due to other priority work in access and charging, such as the Transmission Access Review[86] and Project Transmit[87]. National Grid carried out a review of embedded benefits in 2013/14, which concluded it would be prudent to wait for more information on the level of embedded generation and its impact on transmission system development before proposing any changes. In the time that has passed since that review, a large volume of embedded capacity has come online. In addition to this, the TDR has also increased significantly from c.£27/kW to c.£45/kW, with a rise to c.£72/kW forecast in 2020/21.

Historically, the value of the total transmission charge was lower and the amount of embedded generation was small. As such, whilst of a concern, the distortions were smaller. As transmission charges have increased and the level of embedded generation capacity on the system has grown, the size of payments in relation to

[85] Examples of documents where embedded benefits are discussed is 30 July 2007, Transmission Arrangements for Distributed Generation - Working Group Report and Next Steps https://www.ofgem.gov.uk/ofgem-publications/55753/070730tadgcoveringletterfinal.pdf and 23 January 2009, Conclusions in respect of the consultation on the discount for small transmission connected generators from 1 June 2009 https://www.ofgem.gov.uk/publications-and-updates/conclusions-respect-consultation-discount-small-transmission-connected-generators-1-june-2009-under-standard-licence-condition-c13-and-notice-under-section-11a-electricity-act-1989.

[86] http://webarchive.nationalarchives.gov.uk/20130402174434/http://www.ofgem.gov.uk/Networks/Trans/Archive/ElecTrans/TADG/Documents1/Small%20Generators.pdf.

[87] http://www.nationalgrid.com/NR/rdonlyres/44201E6D-B4A1-4D94-BF50-342350ED3D69/43170/IndustryLetter_final_review.pdf.

avoided TNUoS charges (TDR payment) that are available to embedded generation in exchange for reducing a suppliers' TNUoS charges has grown dramatically. These payments are not available to generation connected to the distribution which is over 100MW, or transmission generation, and as such, there is now a large incentive for generators to locate on the distribution system if they are under 100MW in size. The cost of these payments are also recovered from customers, meaning that the increase of these payments mean an increased and escalating cost to consumers.

Drivers of the increase in the TDR

The TDR has increased, and is forecast to increase, due to four main reasons, discussed below.

1. **Increased total TNUoS cost as RIIO allowed revenues increase** – The allowed revenue for the Transmission Operators has increased and will be about £3.7bn in 2020/21, compared to £2.7bn today. This means more a rise in the per kW charge. As smaller EG are paid the inverse of the TDR, however, the forecast payment to them is also set to increase.

2. **Increased proportion of TNUoS cost is being paid by demand** – There is currently a cap on the value of charges that can be recovered from generation connected to the transmission system. This is set by European law. This means that more of the TNUoS charge has to be recovered from demand.

3. **Increasing proportion of demand costs is collected through the residual** – The locational element of the demand tariff is forecast to go negative, meaning that more cost is recovered through the residual.

4. **The TNUoS charge is being collected from a shrinking demand charging base** – As more generation locates on the distribution network and the level of gross demand decreases, the charging base (demand off the transmission system) decreases. As the allowed revenues for the Transmission Operators is set by RIIO, a reduced charging base means a smaller number of users over which to recover the costs, and a consequential increase in per kW charges.

Appendix 3 – The CUSC process and the CUSC panel vote

CUSC Industry-Led Change Management Process

The CUSC, in common with the other GB energy network codes, is subject to an industry-led change management process. Modifications are produced by CUSC signatories for discussion and development by workgroups, and administered by National Grid in its capacity as Code Administrator. Proposals can also be put forward by non-signatories by being sponsored by a CUSC signatory, National Grid or Ofgem, or by becoming CUSC signatories.

Proposals are developed and judged according to whether, and how well, they further the objectives outlined in the CUSC. The CUSC charging objectives are set out in the main body of the document, but in brief, the charging methodologies should further the following objectives:

- Facilitation of effective competition in the generation and supply of electricity and (where it is consistent with this) facilitation of competition in the sale, distribution and purchase of electricity;
- Facilitate charges which reflect, as far as is reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;
- Facilitate charges that take account of the developments in transmission licensees' transmission businesses;
- Facilitate charges that comply with the applicable European legislation; and
- Promotes efficiency in the implementation and administration of the system charging methodology.

After development of, and consultation on the original/WACMs, workgroup participants vote on how the proposals meet or better facilitate these objectives. Those that are voted as being better than the status quo will be put to the CUSC panel for consideration, who vote against the same CUSC objectives. At this stage of the workgroup vote, the chair has the ability to put forward additional WACMs if they think they better facilitate the CUSC objectives (and didn't get through the workgroup vote). All WACMs which are voted as better facilitating the CUSC objectives by the workgroup, or are saved by the workgroup chair, will be put to Ofgem for decision, with Ofgem having a full choice of all options irrespective of the CUSC Panel recommendation.

After the CUSC Panel has voted on the original proposals, and relevant WACMs, they make a recommendation on which WACM(s) better, or best, meet the CUSC objectives, with this recommendation being submitted for decision in the FMR.

Make-up of the CUSC panel and Ofgem decision

Ofgem attends the meetings of the Panel and working groups as an observer and is committed to the independent operation of the panel and the independent change management process. We will take into account the CUSC Panel recommendation as well as all other relevant matters before making our decision on whether to approve or reject any change, based on our assessment against the CUSC objectives and our wider statutory duties. Where proposals will have a potentially large impact, we will carry out an impact assessment, as in this case.

CUSC panel vote

The tables below show how the CUSC Panel voted on the original CMP264 and CMP265 proposals, and the relevant WACMs.

The first vote is on whether the proposal is better than the baseline. Each proposal/WACM is voted on in turn, with all panel members voting on each proposal. In total there are 9 panel members, meaning that the number of votes is out of a total of 9 votes.

The second vote is a vote on which proposal best meets the CUSC objectives. Each panel member only gets one vote for this section.

It should be noted here, as explained in the main body of the document, that one of the CUSC Panel members abstained from voting throughout.

WACM Number	Better than the baseline	Best
264 Original	3	
WACM 1	8	
WACM 2	7	
WACM 3	8	4
WACM 4	7	
WACM 5	7	3
WACM 6	5	
WACM 7	5	1
WACM 8	1	
WACM 9	1	
WACM 10	1	
WACM 11	1	
WACM 12	1	
WACM 13	1	
WACM 14	1	

WACM Number	Better than the baseline	Best
265 Original	3	1
WACM 1	7	
WACM 2	6	
WACM 3	7	3
WACM 4	6	
WACM 5	6	3
WACM 6	5	
WACM 7	5	1
WACM 8	1	
WACM 9	1	
WACM 10	1	
WACM 11	0	
WACM 12	1	
WACM 13	1	
WACM 14	1	

WACM 15	1	
WACM 16	1	
WACM 17	1	
WACM 18	1	
WACM 19	2	
WACM 20	0	
WACM 21	0	
WACM 22	1	
WACM 23	1	

WACM 15	1	
WACM 16	1	
WACM 17	1	
WACM 18	0	

Appendix 4 – Potential TNUoS and BSUoS revenues

In this section we provide illustrative examples of the level of embedded benefit that three smaller sub-100MW embedded generators could realise, per kilowatt, according to their different generation profiles.

The three generation patterns are listed below, as a percentage of their maximum capacity. Generator A and C are conventional generation, and generator B is intermittent wind generation. These illustrative examples are broadly meant to represent baseload generation (A), intermittent wind (B) and peaking smaller plant (C).

	Generator A	**Generator B**	**Generator C**
Output at peak	90%	5%	90%
Load Factor across the year	90%	30%	5%

Below we show an illustrative example of the potential revenues that these generators could realise through TNUoS and BSUoS payments and avoided charges. Please note, these are illustrative only and are intended to show the potential impact of a reduction in the TDR payment level to the avoided cost of GSP infrastructure (in this example the 13/14 estimate of £1.62/kW) on generators who have three different operating patterns.

It should be noted that for these examples, it is assumed that 90% of the benefit is passed onto the generator, TNUoS is at current levels (£45.33/kW) and BSUoS is averaged at £2.40/MWh. In reality, plant responding to periods of high BSUoS levels could realise much higher BSUoS payment, up to c. £47/MWh according to the most recent settlement final BSUoS data. Please note BSUoS is charged on a £/MWh basis, though this example converts this into £/kW.

	Status quo (£45.33/kW TDR payment) £/kW			TDR payment reduced to £1.62/kW £/kW		
	South Scotland			**South Scotland**		
	Generator A	Generator B	Generator C	Generator A	Generator B	Generator C
TNUoS Demand (payment to)	£32.60	£1.81	£32.60	£0.00	£0.00	£0.00

TNUoS Generation (avoided)	£8.23	£5.01	£4.64	£8.23	£5.01	£4.64
BSUoS (avoided)	£17.03	£5.68	£0.95	£17.03	£5.68	£0.95
BSUoS (payment to)	£17.03	£5.68	£0.95	£17.03	£5.68	£0.95
Total EB	**£74.88**	**£18.17**	**£39.13**	**£42.28**	**£16.36**	**£6.53**

	Midlands			**Midlands**		
	Generator A	Generator B	Generator C	Generator A	Generator B	Generator C
TNUoS Demand (payment to)	£37.05	£2.06	£37.05	£1.64	£0.09	£1.64
TNUoS Generation (avoided)	£2.41	£0.60	£2.13	£2.41	£0.60	£2.13
BSUoS (avoided)	£17.03	£5.68	£0.95	£17.03	£5.68	£0.95
BSUoS (payment to)	£17.03	£5.68	£0.95	£17.03	£5.68	£0.95
Total EB	**£73.52**	**£14.02**	**£41.07**	**£38.11**	**£12.05**	**£5.67**

	London/Central London			**London/Central London**		
	Generator A	Generator B	Generator C	Generator A	Generator B	Generator C
TNUoS Demand (payment to)	£42.01	£2.33	£42.01	£6.61	£0.37	£6.61
TNUoS Generation (avoided)	-£5.78	-£4.88	-£8.42	-£5.78	-£4.88	-£8.42
BSUoS (avoided)	£17.03	£5.68	£0.95	£17.03	£5.68	£0.95
BSUoS (payment to)	£17.03	£5.68	£0.95	£17.03	£5.68	£0.95
Total EB	**£70.30**	**£8.81**	**£35.49**	**£34.89**	**£6.84**	**£0.08**

Appendix 5 – Efficient Market Operation

Efficient Market Operation and the Merit Order

Under normal market operation, generators enter the market and generate power when their marginal cost of running is lower than or equal to the market price, as this means that they will not run at a loss.

The order in which plant generates power according to their ability to generate at lowest cost is called the "merit order", and generally a well-functioning market will see the cheapest and most cost effective generators entering first, with more expensive generators only running when higher prices justify them coming online. This tends to lead to the most efficient outcome as the lowest-cost generators run more, and the higher-cost generators less.

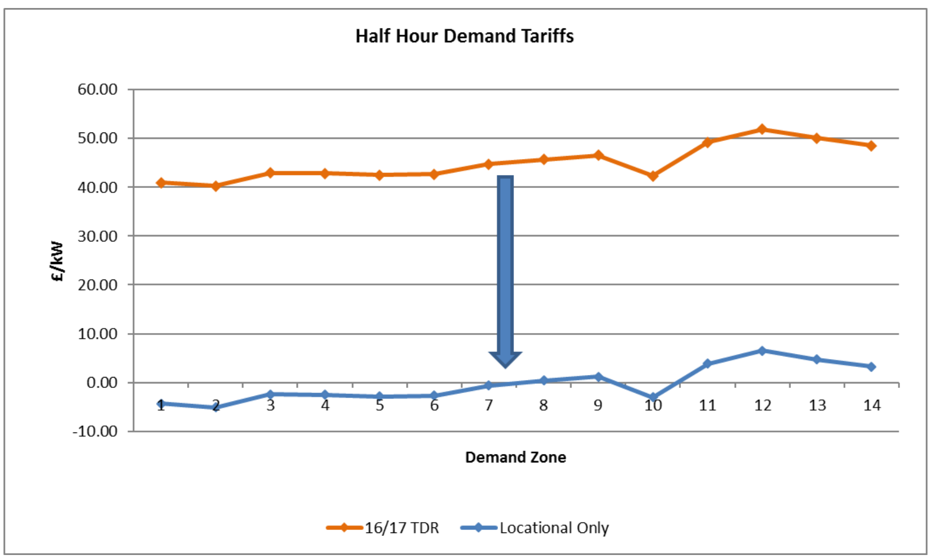
Additional revenues from non-market sources, such as triad revenues, lead to generators running even when they are not the next most-efficient generator, which leads to higher operating costs for the same outcome. This type of operation, where a plant generates instead of other plants that are more cost-effective, is known as running "out of merit".

Such running would lead generators to make a loss, unless they have financial incentives to run that aren't driven by the market, such as running to hit triad. While the triad periods are traditionally aligned with the highest peak prices, in recent years this has not always been the case and peak wholesale prices have been depressed.

Appendix 6 – Methods of preventing smaller EG facing incentives not to generate in Security of Supply situations

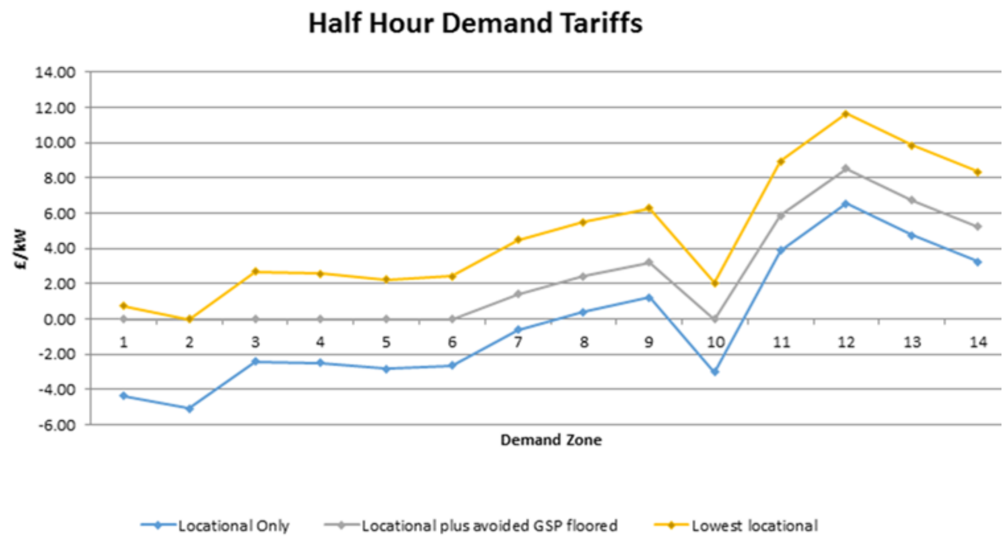
All of the WACMs have a value of 'x' which is added as an explicit payment. These range from zero to £45.33/kW. This value is in addition to the value of the locational signal which the generators receive. The next few graphs illustrate some of these principles.

All smaller EG will receive the locational signal as an embedded benefit and then have an additional value of 'x' which will replace the TDR which is currently £45.33/kW. The graph below shows the effect of removing the TDR of £45.33/kW and exposing only the locational signal only.

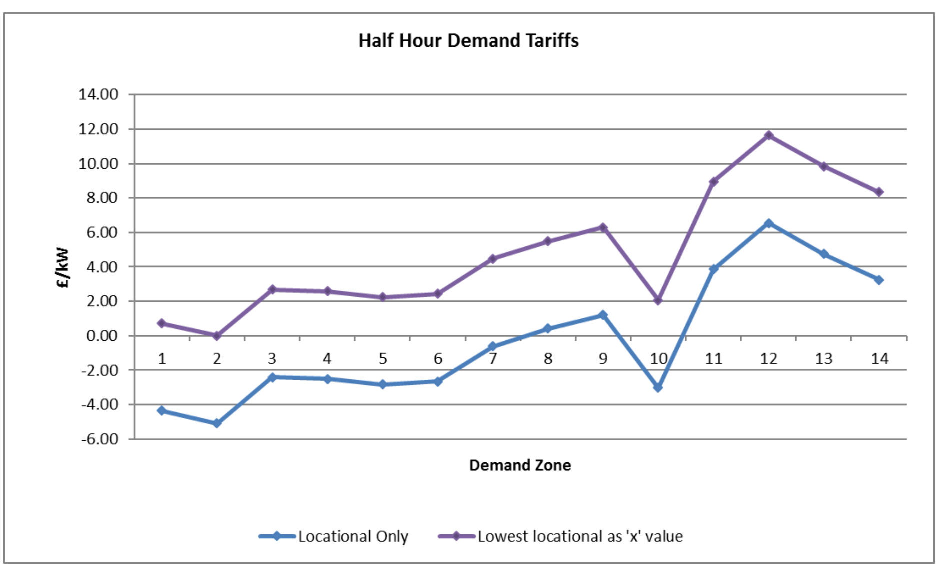


Most options prevent smaller EG facing inverse demand charges of less than zero, so as to remove an incentive not to run at peak time. A situation where smaller EG had an incentive not to run at peak was seen in the CMP264/265 workgroups as having security of supply implications, and also revenue implications, as it was not clear how revenues could be recovered from non-CUSC signatories[88]. The effect of this is shown below, with a small number of zones seeing their charge amended to prevent them having to pay.

[88] Many smaller EG are not CUSC signatories, though others are.



There is an argument, that by flooring at zero (as many of the WACMs do) the locational signals that the embedded generators receive are dampened, as the difference between charges for those in low-charge and high-charge areas is reduced. As such, National Grid proposed a WACM which adds a value of 'x' which is equal to the lowest locational value in that year. This prevents the need for a floor at zero, prevents any embedded generators seeing a negative signal, and preserves the locational difference between them. The graph below shows the effect of the adding the lowest locational value has – effectively it moves the whole locational signal up the graph. This means that all zones receive extra revenue, rather than just a small number, and the revenue is more sizable.



Appendix 7 – Full review against CUSC Objectives when compared to the status quo

WACM Number	Facilitating Competition	Cost-Reflective Charging	Charges that take account of developments in transmission businesses;	Taking account of EU Legislation	Efficiency in imp. and admin.	Better facilitate CUSC objectives
264 Original	Better than status quo	Neutral	Neutral	Neutral	Worse than Status Quo	Better than status quo
265 Original	Neutral	Neutral	Neutral	Neutral	Worse than Status Quo	Neutral
WACM 1	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 2	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 3	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 4	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 5	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 6	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 7	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 8	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo
WACM 9	Better than status quo	Better than status quo	Neutral	Neutral	Neutral	Better than status quo

WACM 10	Better than status quo	Neutral	Neutral	Neutral	Neutral	Better than status quo
WACM 11	Neutral	Neutral	Neutral	Neutral	Neutral	Neutral
WACM 12	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo
WACM 13	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo
WACM 14	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo
WACM 15	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo
WACM 16	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo
WACM 17	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo
WACM 18	Neutral	Neutral	Neutral	Neutral	Worse than Status Quo	Neutral
WACM 19	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo
WACM 20	Worse than Status Quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Worse than Status Quo
WACM 21	Worse than Status Quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Worse than Status Quo
WACM 22	Worse than Status Quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Worse than Status Quo
WACM 23	Better than status quo	Better than status quo	Neutral	Neutral	Worse than Status Quo	Better than status quo

Appendix 8 – The model, assumptions and results

Model information

Ofgem commissioned Frontier and Lane Clark and Peacock LLP (LCP) to carry out economic analysis of the expected consumer's costs and benefits of change to the embedded benefits regime. This was done using LCP's EnVision model, a fully integrated model of the GB power market, and produced an estimate of the system and consumer's costs/benefits between now and 2034. This model is used by BEIS (formerly DECC) for policy analysis and was used by National Grid to analyse the effects of the Electricity Market Reform. The model has undergone extensive assurance testing, with DECC carrying out a detailed review of the model in 2014. Ofgem reviewed LCP's quality assurance process and agreed the input assumptions, using National Grid/BEIS inputs wherever possible.

Modelling Assumptions

Renewable build and demand growth are in line with National Grid's FES 2016 "Slow Progression".[89] Inputs include:

- Demand;
- Renewable build, nuclear build/closure, coal closure;
- Commodity prices: gas, coal, carbon (updated with the latest forwards for 2016-19 period); and
- Interconnector build.

Cost assumptions

Cost assumptions, including CCGT and OCGT capex use BEIS low estimates (November 2016):

Technology	Build cost (£2015 real /kW)	Fixed opex (£2015 real/kW/pa)
CCGT	416	17.6
OCGT	339	8.9
Reciprocating diesel	255	11.0
Reciprocating gas	345	11.0

Under the BEIS low assumptions, the implied total capital expenditure of a reciprocating diesel engine was below the requirement of a new build in the capacity mechanism. While we understand there is some evidence that diesel can be built for less, the CM arrangements require costs of this level to be demonstrated. As such,

[89] http://fes.nationalgrid.com/.

the estimate for reciprocating diesel capex is set at the CM minimum bid level of £255/kW.

Other assumptions

- **Build Limits –** Set for reciprocating engines at 2GW total per year for the first two years (2020/21 and 2021/22 delivery) and then 1GW total per year thereafter.
- **Coal exit –** Occurs in line with the National Grid FES "Slow Progression" scenario with ~6GW of coal on the system in 2020/21, ~2GW for 2021/22 and all coal being removed for 2022/23.
- **TDR Payments –** Assumed 90% pass through by suppliers to the smaller EG. **TNUoS demand charges –** Based on National Grids published forecasts through to 2021 and then flat thereafter.

Model validation

We validated the modelling carried out by LCP, by running the Capacity Assessment model (CA) using Frontier/LCPs assumptions regarding demand, interconnector flows, conventional generational fleet and wind supply in the status quo scenario. This yielded results that are in line with Frontier Economics/LCP outputs.

The features of the EnVision makes it useful for forecasting medium to long term trends in the energy market, while the Capacity Assessment (CA) model is usually not run for periods longer than the next five years. For this reason, this validation took place for the period up to winter 2020/21 only.

LCP performed some "backcasting" runs of the model for the December 2016 T-4 Capacity Auction and found that the BEIS low capital cost assumptions give a 2020/21 clearing price result very close to the actual clearing price of £22.50/kW.

Modelling results

The results of the modelling, for each scenario, can be seen below, showing both the system cost saving, and the consumer cost saving associated with each of the modelling scenarios. These values are in 2016 real terms.

		Grandfathering option			
		None	A - CM/CfD Capacity	B - Existing capacity	C - Both
Scenario 1	System saving (£mn)	434	434	434	434
	Consumer saving (£mn)	1,811	1,811	1,811	1,811
Scenario 1 phased	System saving (£mn)	434	434	434	434
	Consumer saving (£mn)	1,813	1,813	1,812	1,811
Scenario 2	System saving (£mn)	1,424	1,424	1,424	1,424
	Consumer saving (£mn)	5,249	4,761	3,803	3,314
Scenario 2 phased	System saving (£mn)	1,415	1,415	1,415	1,415
	Consumer saving (£mn)	5,051	4,585	3,710	3,244
Generator Residual	System saving (£mn)	1,878	1,878	1,878	1,878
	Consumer saving (£mn)	7,486	6,755	5,306	4,575
Generator Residual phased	System saving (£mn)	1,831	1,831	1,831	1,831
	Consumer saving (£mn)	7,404	6,715	5,416	4,728
Scenario 3	System saving (£mn)	2,094	2,094	2,094	2,094
	Consumer saving (£mn)	7,447	6,599	4,930	4,083
Scenario 3 phased	System saving (£mn)	2,058	2,058	2,058	2,058
	Consumer saving (£mn)	7,194	6,387	4,862	4,054

As mentioned in the draft impact assessment, it was not proportionate to model all of the options directly, therefore, we used the modelled scenarios as a proxy for those not modelled directly. The table below shows how we assessed the directly modelled WACMs:

WACM Number	Modelling option	Consumer cost saving to 2034 (£mn)	System cost saving to 2034 (£mn)
WACM 1	Generator residual	7486	1878
WACM 2	Generator residual with phasing	7404	1831
WACM 3	Scenario 3	7447	2094
WACM 4	Scenario 3 with phasing	7194	2058
WACM 10	Scenario 1	1811	434
WACM 12	Generator residual with grandfathering	6755	1878
WACM 13	Scenario 3 with CM/CfD grandfathering	6599	2094
WACM 16	Scenario 2 with CM/CfD grandfathering	4761	1424

The table below gives an explanation as to how we estimated the options which were not modelled directly. The closest modelled scenarios were used, to replicate the background build out and were conservative in their estimations:

WACM Number	Modelling option	Consumer cost saving to 2034 (£mn)	System cost saving to 2034 (£mn)
264 Original	Estimated from Scenario 3 with grandfathering for existing capacity and CM capacity	4083	2094
265 Original	Estimated from Scenario 3 plus the difference between the CM grandfathering and the no grandfathering options as these operators will not be paid.	2659	434
WACM 5	Estimated between Scenario 3 with phasing and Generator residual with phasing.	7194 - 7404	1831
WACM 6	Estimated from Scenario 2*	5249	1424
WACM 7	Estimated from Scenario 2 with phasing	5051	1415
WACM 8	Estimated from a midpoint between Scenario 2 and Scenario 1	3530	929

WACM 9	Estimated from Scenario 2	5249	1424
WACM 11	Estimated from Scenario 1**	1811	434
WACM 14	Estimated from the Generator residual with CM grandfathering.	6755	1878
WACM 15	Estimated from Scenario 2 with CM/CfD grandfathering*	4761	1424
WACM 17	Estimated from a midpoint between Scenario 2 with grandfathering and Scenario 1 with grandfathering	3286	929
WACM 18	Estimated from Scenario 1 with CM/CfD grandfathering**	1811	434
WACM 19	Estimated from Scenario 3 with CM/CfD and existing grandfathering	4083	2094
WACM 20	Estimated from the Generator residual with full grandfathering. Will underestimate of the true consumer cost saving.	4575	1878
WACM 21	Estimated from Scenario 2* with existing and CM/CfD grandfathering. The later grandfathering cut-off date is likely to increase the cost of grandfathering	3314	1424
WACM 22	Estimated from Scenario 3 with CM/CfD and existing grandfathering. The later grandfathering cut-off date is likely to increase the cost of grandfathering	4083	2094
WACM 23	Estimated from Scenario 2 with existing and CM/CfD grandfathering and Scenario 2***	4282	1424

*When averaged over the period to 2034, £20.12/kW can be compared to the average lowest locational value. The later grandfathering cut-off date is likely to increase the cost of grandfathering.

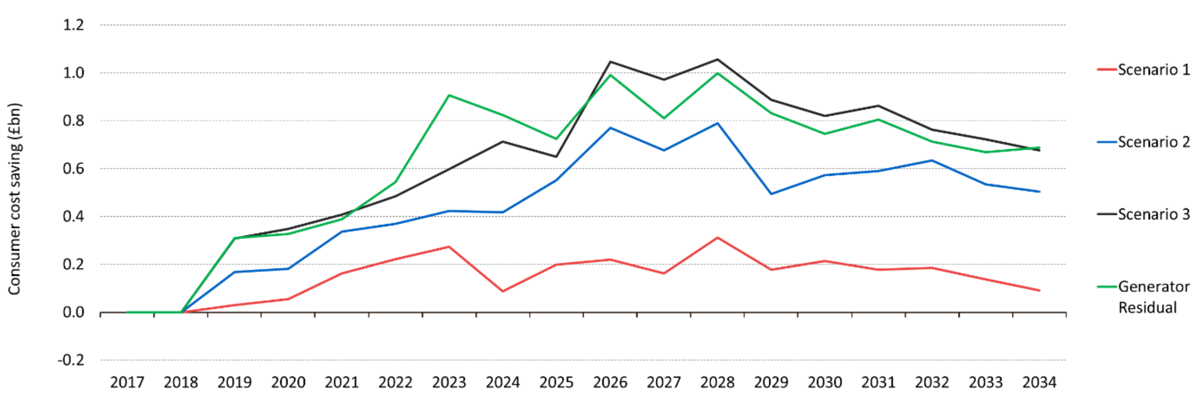
**Whilst the TDR payments are lower in early years, they rise higher than £45.33/kW in later years (from 2019 onwards). As such, we can assume the benefit are less than stated.

***Consumer savings may be lower if this payment level is above the 'tipping point' at which further EG capacity is built.

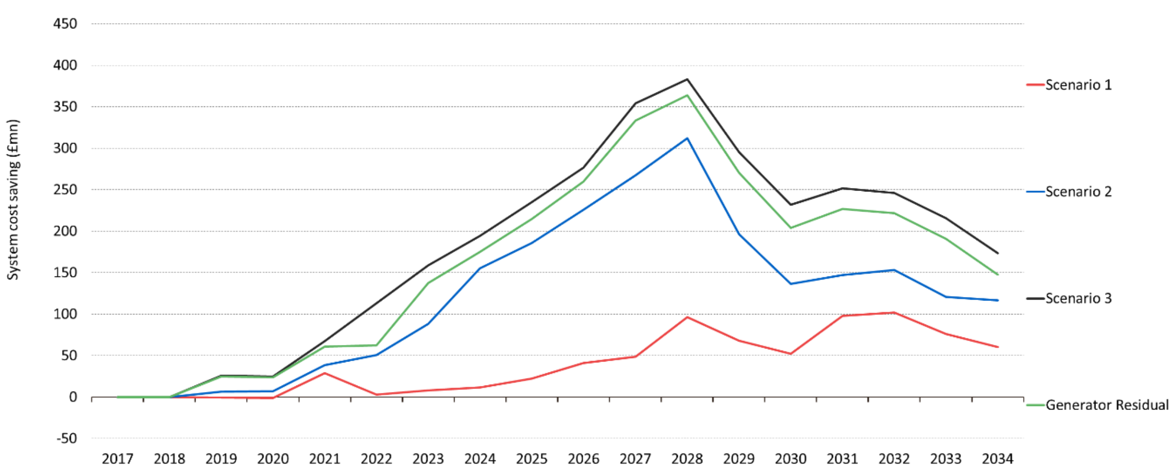
Graphs for all scenarios

Here we provide the graphs for the consumers cost savings, system cost savings, the CM clearing price and Loss of Load Expectation (LOLE), over time, for the four core scenarios, when compared to status quo. The phased options for each has not been shown but follow a similar pattern to the core scenarios. The values are the nominal savings per year.

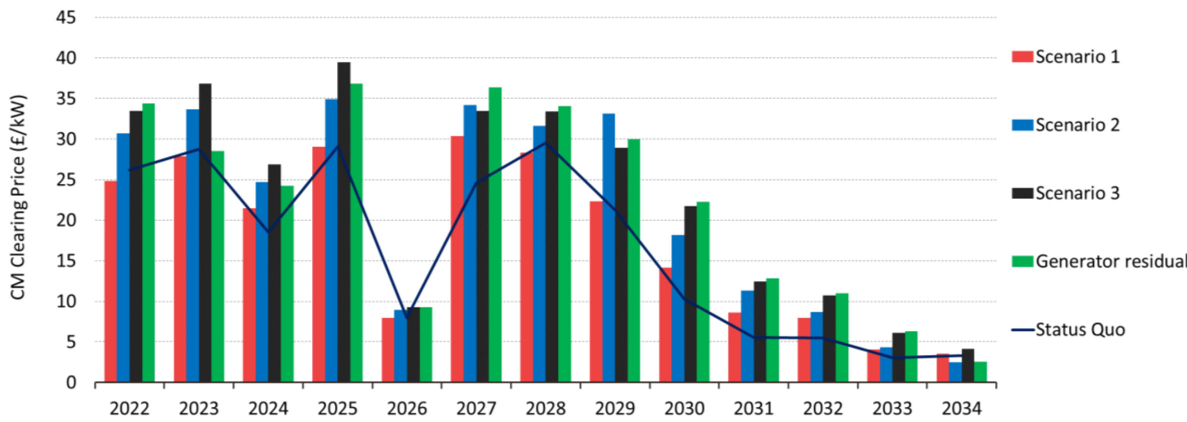
Consumer cost saving



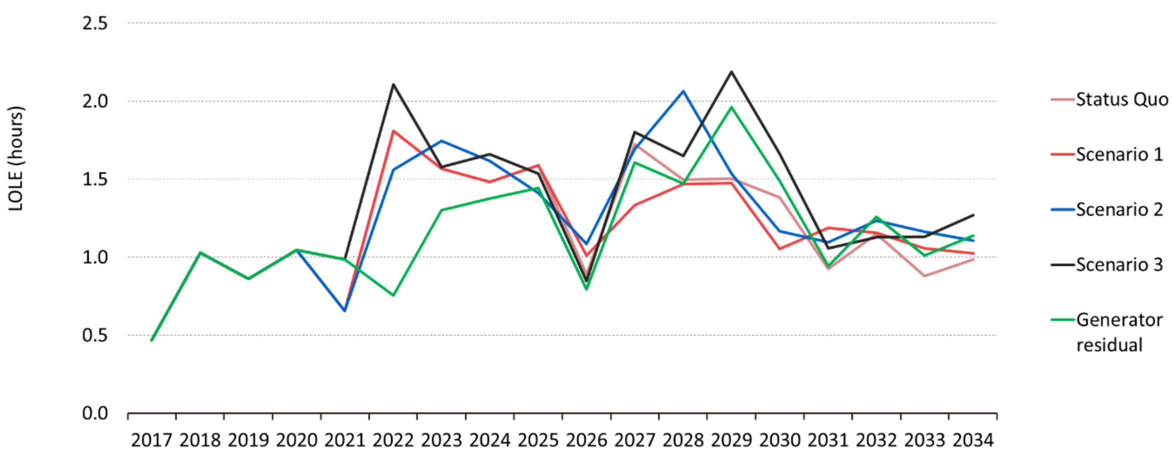
System Cost saving



CM clearing price



Loss of Load Expectation



Appendix 9 - Glossary

A

Allowed Revenue

Energy networks are natural monopolies and therefore there is no realistic way of introducing competition to keep prices down. Instead, a regulator like Ofgem can set Allowed Revenues for a monopoly such as a network company to restrict the amount of money that can be earned over the length of a price control period.

Ancillary Services

In a power system, electricity generation and consumption (demand) must always balance. Changes in consumption and disturbances in generation impact the system balance and can cause frequency deviations in the grid. Ancillary services can provide these balancing needs and support the continuous flow of electricity so that supply will continually meet demand.

B

Balancing Services Use of System Charges

The Balancing Services Use of System (BSUoS) charge recovers the cost of day to day operation of the transmission system. Generators and suppliers are liable for these charges, which are calculated daily as a flat tariff across all users. The methodology that calculates the BSUoS is set out in Section 14 of the CUSC.

C

Capacity Market

The Capacity Market (CM) provides a regular retainer payment to reliable forms of capacity (both demand and supply side), in return for such capacity being available when the system is tight.

Connection and Use of System Code

The Connection and Use of System Code (CUSC) is the contractual framework for connection to, and use of, the National Electricity Transmission System (NETS). National Grid is the Code Administrator for the CUSC and maintains the Code.

Contract for Difference

Contracts for Difference (CFD) provide long-term price stabilisation to low carbon electricity generators, allowing investment to come forward at a lower cost of capital.

A CFD is a private law contract between a low carbon electricity generator and the Low Carbon Contracts Company (LCCC), a government-owned company. A generator party to a CFD is paid the difference between the 'strike price' - a price for electricity reflecting the cost of investing in a particular low carbon technology - and the 'reference price' - a measure of the average market price for electricity in the GB market.

CUSC Panel

The CUSC Modifications Panel is the standing body responsible for implementing or supervising the implementation of approved CUSC modifications. The CUSC Panel meets on a monthly basis.

D

Dispatch

Refers to a generators decision, or not, to generate. Dispatchable generation is generation whose power output can be turned on or off, or adjusted according to a dispatch arrangement to maintain the balance between generation and demand. Great Britain uses a 'self-dispatch' mechanism. Under this approach, resources (buyers and sellers of electricity) determine a desired dispatch position for themselves based on their own economic criteria to provide commercial independence within a market.

Distribution Network

Electricity distribution networks carry electricity from the high voltage transmission grid to industrial, commercial and domestic users. There are 14 licensed distribution network operators (DNOs) in Britain, and each is responsible for a regional distribution services area.

E

Embedded Benefits

Embedded benefits are the payments which smaller (sub-100MW) Embedded Generators get, and the charges they do not have to pay, compared to larger (over 100MW) EG on the distribution system and transmission connected generators. They are so called because they provide a benefit to these generators, not because they benefit these generators provide a particular benefit to the system. Smaller EG can realise these benefits due to their location on the distribution system and their size. This is because, under the current regime, generation connected to the distribution network that is below 100MW (smaller EG) is treated not as generation, but as 'negative demand'. As Transmission charging for demand is currently calculated based on a user's net demand at a Grid Supply Point (GSP) group, increasing use of smaller EG reduces a supplier's liability for transmission charges.

Embedded Generators

Also called EG, distributed generation, and distribution-connected generation. These are generators connected to the distribution system, rather than the transmission system. Smaller (sub-100MW) EG do not pay transmission charges and can receive Embedded Benefits. Larger (over 100MW) EG do pay transmission charges and do not receive Embedded Benefits.

F

Final Modification Report

Once the CUSC Modification Proposal consultation phase is completed, a Draft CUSC Modification Report is produced for the CUSC Modifications Panel to vote on. The Panel must vote on whether they believe that the proposal better facilitates the Applicable CUSC Objectives. The voting and recommendations are included in a Final CUSC Modification Report (FMR) which is then submitted to the Authority for a decision (unless the Self-governance route has been taken).

G

Grid Supply Point

A Grid Supply Point (GSP) is a Systems Connection Point at which the Transmission System is connected to a Distribution System.

I

Industry Self-Governance

Industry Self-governance is an alternative route through which a CUSC Modification Proposal can be progressed. It allows the CUSC Modification Panel to make a determination on a CUSC Modification Proposal instead of the Authority. The modification may still go through the Workgroup phase if deemed appropriate. Self-governance is used for minor amendments that are deemed to have non-material changes or no impact on: existing or future electricity consumers; operation of the National Electricity Transmission System; security or safety of supply or sustainable development; competition; or CUSC governance or modification procedures. The CUSC Modifications Panel decide the appropriate route through which a CUSC Modification Proposal should be progressed.

O

Ofgem

Ofgem is the Office of Gas and Electricity Markets. Our governing body is the Gas and Electricity Markets Authority and is referred to variously as GEMA or the Authority. We use "the Authority", "Ofgem" and "we" interchangeably in this document.

S

Security of Supply

Security of supply is ensuring the uninterrupted availability of energy sources at an affordable price. National Grid publish an outlook report on the availability of gas and electricity supplies ahead of each winter. The report contains an assessment of the risk to suppliers in Britain over the next winter.

Significant Code Review

The Significant Code Review (SCR) process provides a tool for the Authority to initiate wide ranging change and to implement reform to a code-based issue. The Authority would consult before deciding on whether to undertake an SCR and consider the responses to the consultation before deciding on whether or not to launch an SCR.

T

Targeted Charging Review

Ofgem intend to consult on launching a targeted charging review (TCR) in early 2017. The TCR may require a significant code review to consider issues such as some aspects of the Balancing Services Use of System charges and allocation of sunk/fixed costs, including for storage and 'behind the meter' generation.

TNUoS Demand Locational

TNUoS Demand Locational charges are locational specific, cost reflective, charges of an incremental, forward-looking nature that are levied on demand users.

TNUoS Demand Residual

TNUoS Demand Residual (TDR) charges are top-up charges which ensure that the appropriate amount of allowed revenue is collected from demand users once locational, cost reflective, charges have been levied. The amount of revenue which needs to be recovered from TDR charges does not change when individuals use the system differently. Any TDR charges avoided by the use of smaller EG have to be recovered from other users of the network, leading to higher charges for everyone else.

TNUoS Generation Locational

TNUoS Generation Locational charges are locational specific, cost reflective, charges of an incremental, forward-looking nature that are levied on generators.

TNUoS Generation Residual

TNUoS Generation Residual (TGR) charges are top-up charges which ensure that the appropriate amount of allowed revenue is collected from generators users once locational, cost reflective, charges have been levied. If too much revenue has been collected from the locational charges, the TGR can be a negative charge that pays revenue back to generators.

Transmission Network

The transmission network comprises of circuits operating at high-voltage, defined as; 400kV, 275kV, and 132kV (in Scotland only). The system is responsible for the transmission of energy from Generators to lower voltage distribution networks, which subsequently distribute the supply to users. National Grid is responsible for managing the operation of both the England and Wales transmission system, the high voltage electricity transmission network in Scotland, and the high voltage networks located in offshore waters surrounding Great Britain.

Transmission Network Use of System Charges

Transmission Network Use of System Charges (TNUoS), also called Transmission Use of System Charges TUoS) charges. These charges recover the costs of the Transmission Network and are charged to both demand users and generators. They are broadly separated into locational charges, which relate to the incremental cost of using the network in a specific location, and residual charges that recover the remaining costs and are non-locational.

Transmission Owners

The high-voltage electricity transmission network in England and Wales is owned by National Grid Electricity Transmission plc (NGET), in south and central Scotland it is owned by Scottish Power Transmission plc (SPT), and in north Scotland by Scottish Hydro Electric Transmission plc (SHET). These companies are designated as Transmission Owners (TOs) in legislation.

Triad periods

Triad periods or "The Triad" refers to the three half-hour settlement periods with highest system demand between November and February, separated by at least ten clear days. National Grid uses the Triad to determine TNUoS charges for customers with half-hour metering. The Triads for each financial year are calculated after the end of February, using system demand data for the half-hour settlement periods between November and February.

W

Wholesale Market

Electricity cannot be stored in large amounts. Supply and demand for electricity must be matched, or balanced, at all times. In GB, this is primarily done by suppliers, generators, traders and customers trading in the competitive wholesale electricity market.

Workgroup Alternative CUSC Modifications

CUSC Modification Proposals (CMP) may need to be developed further by subject matter experts before going to consultation. Where this occurs, a Workgroup will be established to assist the CUSC Panel in evaluating the CMP. The Workgroup can develop alternative solutions to the CMP. These are referred to a Workgroup Alternative CUSC Modifications (WACMs). WACMs may be raised where, as compared with the original CMP, they better facilitate achieving applicable CUSC objectives. Subject to certain provisions, the Workgroup will consult on the CMP and WACMs with CUSC parties and other appropriate persons.

Appendix 10 - Feedback on this consultation

We want to hear from anyone interested in this document. Send your response to the person or team named at the top of the front page.

We've asked for your feedback in each of the questions throughout it. Please respond to each one as fully as you can.

Unless you mark your response confidential, we'll publish it on our website, www.ofgem.gov.uk, and put it in our library. You can ask us to keep your response confidential, and we'll respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004. If you want us to keep your response confidential, you should clearly mark your response to that effect and include reasons.

If the information you give in your response contains personal data under the Data Protection Act 1998, the Gas and Electricity Markets Authority will be the data controller. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. If you are including any confidential material in your response, please put it in the appendices.

General feedback

We believe that consultation is at the heart of good policy development. We are keen to hear your comments about how we've conducted this consultation. We'd also like to get your answers to these questions:

1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

Please send your comments to stakeholders@ofgem.gov.uk

Appendix 11 – Ofgem Impact Assessment Template

Title: **Embedded Benefits: Draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change the electricity transmission charging arrangements**	**Draft Impact Assessment (IA)**
Division: **Energy Systems** Team: **Electricity Network Charging**	Source of intervention: **Domestic**
Type of Draft IA: **Qualified under Section 5A UA 2000**	Type of measure: **Codes**
Scope: **Full**	Contact for enquiries: **Andrew Malley**

Summary: Intervention and Options

Rationale for intervention, objectives and options

What is the problem under consideration? Why is Ofgem intervention necessary?

The current network charging regime does not provide a level playing field for generators. Any embedded generation (EG) below 100MW ('sub 100MW EG') on the distribution system can obtain embedded benefits (EBs), others generators cannot. As EG has grown, additional costs are passed to consumers. The largest component of EBs is the Transmission Network Use of System (TNUoS) Demand Residual (TDR) payments that sub 100MW EG can receive. Suppliers pay sub 100 MW EG payments to reduce their liability for the TDR charges, or National Grid pays sub 100 MW EG these payments directly, which provides these generators with a revenue stream not available to other generators. The cost of these payments is picked up by other consumers, as is the avoided network charges.

The primary market distortions that TDR payments lead to are:

i) Sub 100 MW EG can use these payments to lower their bids into the Capacity Market
ii) Within the wholesale market, revenue from these payments means that generation dispatches out of merit order (some higher cost generation operates before lower cost) and ancillary services markets are distorted.

Code modifications to address these issues have been proposed by industry together with CUSC WACMs and we have a specific role to accept or reject these.

What are the policy objectives and intended effects including the effect on Ofgem's Strategic Outcomes?

The objective of Ofgem is to approve a CUSC mod or WACM which best meets our statutory duties and CUSC objectives. We have the option of sending back the proposals. However, in this decision all short-listed options provide benefits to consumers over the medium term which is consistent with our strategic aims.

What are the policy options that have been considered, including any alternatives to regulation? Please justify the preferred option (further details in Evidence Base)

As described within the main text, a total of 25 code modifications have been considered.

The modelled results use a counter-factual which assumes that the demand TNUoS residual increases in line with National Grid forecasts until 2021, after which it remains flat at £72.03/kWh.

The lead policy removes net charging for all sub 100MW EG. New and existing generators will receive a payment of £1.62/kW. The change will be phased from the current level in over three years ending up with the avoided GSP payment (£1.62/kW).

The justification for this option is that it will result in better cost-reflectivity, minimise distortions and hence deliver competition benefits. Some very near term consumer costs could result but turn to consumer benefits that persist in the longer term. Some Transitional arrangements through phased introduction will reduce impacts on investors.

Preferred option - Monetised Impacts (£m)

Business Impact Target Qualifying Provision	No. There are a number of reasons, including the measure has been proposed by industry and it is a competition measure.
Business Impact Target (EANDCB)	Not relevant
Benefit (Explain the basis of monetised impacts e.g. NPV or other). Analysis: Price basis 2016 Real (2016) terms Discount rate 3.5% PV (Present Value) 14 years has been chosen (i.e. 2021-2034)as this is one year longer that the options with the longest grandfathering period	The benefit of the recommended change to consumers has been estimated by LCP/Frontier as £7bn over a 14-year period. The main elements of the consumer savings are in the reduction of the TDR payments (seen in the modelling as 'Additional Triad Avoidance costs'.) Sub 100MW EGEB generation can be used to offset Triad payments (the basis of Transmission Network Use of System Demand Residual (TDR) charges). Prices in the wholesale market may initially increase but in the longer term, reduce which add to this benefit. The cost of Capacity Market payments increase (as they would become more cost reflective). Contract for differences top-up payments price increase as wholesale prices are generally lower over the period System cost savings primarily relate to fuel cost savings as a result of the change in technology that is used (more CCGT, less reciprocating engines). The generating sector as a whole is worse off as they lose by the same amount of the consumers' benefit. However, savings are made on system costs (fuel) which can be netted off their loss.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetised impacts, including mid-tem strategic and long-term sustainability factors (maximum 10 lines). • Security of Supply (LOLE) Calculations of Loss of Load Expectation (LOLE). Model base case results suggest that LOLE might increase but would remain well within 3hr pa standard. • Carbon impacts Carbon impacts are positive but relatively minor • Optionality – the proposed phasing of the introduction of reduced TDR payments provides the option of revision of their level should further analysis suggest that this is beneficial.

Key Assumptions/sensitivities/risks • Key capex assumptions for generation capex are based on BEIS figures for the relevant generation technologies. The base case model run uses the low values. • The change in the cost of capital that could outweigh the consumer benefits has been calculated as x basis point. This is an illustrative calculation. • We have considered the risk that the proposal introduces change too quickly and therefore locks in particular energy system characteristics (this could also be seen as removing future options). We consider that the combination of phasing and other proposed charging work address these risks.

Will the policy be reviewed?	**If applicable, set review date:**
Conditional on Industry self-governance	