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Impact Assessment and Decision on industry proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators

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Contact: Andrew Self, Head of Electricity Network Charging

Team: Energy Systems

Tel: 020 7901 7000

Email: electricitynetworkcharging@ofgem.gov.uk

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 charges. These initial modifications and a further 23 Workgroup Alternative CUSC modifications (WACMs) were subject to detailed assessment against our duties and CUSC objectives. Modelling was undertaken to provide insight into the magnitude and distribution of the impacts of these potential reforms.

Following our March 2017 consultation and our consideration of responses, we have decided that the adoption of WACM4 will best meet the CUSC objectives and our statutory duties and should be implemented in April 2018.

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 decision takes into account the views presented to Ofgem[1] in making this decision.

Associated documents

Embedded Benefits: Consultation on CMP264 and CMP265 minded to decision and draft Impact Assessment, March 2017
https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-consultation-cmp264-and-cmp265-minded-decision-and-draft-impact-assessment

Publication of supplementary modelling report on CMP264/265 minded to decision and optional workshop to discuss report, March 2017
https://www.ofgem.gov.uk/publications-and-updates/publication-supplementary-modelling-report-cmp264265-minded-decision-and-optional-workshop-discuss-report

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

Targeted Charging Review: A consultation, March 2017
https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-consultation

[1] 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

Final CUSC Modification Report CMP264/265/269/270, November 2016
http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937775

Contents

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 Network Use of System (TNUoS) charges, and for smaller EG to be paid to help suppliers 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 principally top-up charges which ensure that the correct amount of allowed revenue is collected from demand users once forward-looking, cost reflective charges have been levied. Any TDR charges avoided by the use of smaller EG have to be recovered from other user of the network, leading to higher charges for everyone else. The payments by suppliers to smaller EG also add to consumer costs.

Two CUSC modification proposals 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 that 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'[2] the 2016/17 level of TDR payments for a subset of smaller EG with 2014 and 2015 CM contracts and Contracts for Difference (CfD), for 10-15 years. We have assessed which of these proposals better, and then ultimately best, facilitates the CUSC objectives and furthers our statutory duties, in line with our obligations as independent regulator.

Assessment and findings

We consider that the current methodology results in a payments to smaller EG of around £370m/year from consumers to smaller EG, a figure that without reform, is forecast to rise to around £700m/year by 2020/21. Further, there is evidence that TDR payments to smaller EG are distorting 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 (FMR) and the responses to our consultation on the draft impact assessment and minded to

[2] A number of proposals allow specific subsets of existing generators to continue to receive payments at the 2016/17 level (£45.33/kW), protecting them from the impact of any changes. This is described in more detail in chapter 3.

decision. Our assessment also takes into consideration the quantitative assessment from the LCP/Frontier modelling that we commissioned, which has been updated and expanded upon in this document. Our draft impact assessment and minded to decision found that several proposals better facilitated the CUSC objectives – in particular on competition and cost reflectivity grounds, with WACM4 the option most likely to best facilitate the objectives. This remains our view, and this document sets out the rationale for our decision and our assessment of the likely impacts.

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 and benefits that they impose, as when faced with the true cost of their behaviour, they are more likely to make efficient choices.

Our view is 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 consider the responses we received to have presented clear evidence of additional benefit brought to the transmission system over and above this level.

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)[3].

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 addition to the cost of these arrangements, which would be borne by consumers, there are potential negative impacts of grandfathering on competition, when compared to similar options without grandfathering, as it would create a significant new distortion between existing and new capacity. Grandfathering would also prevent further changes to the charging arrangements for those network users for 10-15 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 phased introduction of the new arrangements over three years from 2018 to 2020. Allowing a phased introduction of this significant change will provide time for investors and generators to adapt their despatch and business models. 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, as well as other matters.

[3] 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 have consulted on this in March.

Conclusion

Our decision is to direct that WACM4 be implemented. The level of TDR payments to smaller EG should be reduced to the avoided GSP costs and the changes should be introduced through a three-year phased implementation, beginning on 1 April 2018. 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.

Decision Direction

In accordance with Standard Condition C10 of NGET's Transmission Licence, the Authority, hereby directs that WACM4 of modifications CMP264 and CMP265 be made.[4]

[4] This document is notice of the reasons for this decision as required by section 49A of the Electricity Act 1989.

1. Introduction

Chapter Summary

This chapter provides a brief introduction to our duties as an economic regulator, and the purpose of this document.

Purpose of this impact assessment and decision

1.1. In this document, we set out our decision on proposals to change the Connection and Use of System Code (CUSC) as part of our remit as independent regulator of the monopoly networks and their charging arrangements.

1.2. This document incorporates our impact assessment, and sets out the basis for our decision on industry proposals CMP264 and CMP265 to modify the CUSC. It includes our analysis of the Final Modification Report (FMR), as well as the views from the industry consultations, the CUSC Panel and other outputs of the industry code modification process. Our analysis also takes into account of the stakeholder feedback we received through our consultation on our minded to decision and draft impact assessment[5]. This document provides our final view on the options available to us and the likely impact these proposals will have on consumers, industry participants, wider society and the environment. The impact assessment sets out which option best facilitates the CUSC objectives and our statutory duties.

1.3. The impact assessment is produced under section 5A of the Utilities Act 2000. Please note the quantitative modelling included in this 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

1.4. Our principal objective is to protect the interests of existing and future energy consumers. We consider the interests of consumers as a whole to include the pursuit of a reduction of greenhouse gases, the security of supply of gas and electricity, and the fulfilment of the objectives of the Third Package.[6]

[5] https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-consultation-cmp264-and-cmp265-minded-decision-and-draft-impact-assessment
[6] These are the objectives set out in Article 40(a) to (h) of the Gas Directive (2009/73/EC) and Article 36(a) to (h) of the Electricity Directive (2009/72/EC). See http://eur-lex.europa.eu/legal-

1.5. We carry out our functions in a manner which we consider is best calculated to further the principal objective, whether appropriate, by promoting effective competition between persons engaged in, or commercial activities connected with the generation, transmission, distribution and supply of electricity.

1.6. In performing our duties we have regard to the need to secure that all reasonable demands for electricity are met, licence holders are able to finance their activities and the need to contribute to sustainable development. We also have regard to the needs of vulnerable consumers and the principles of Better Regulation. In doing so we balance 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.

content/EN/TXT/PDF/?uri=CELEX:32009L0073&from=EN and http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=EN

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. We also explain the process that has been used to produce this proposal.

Transmission Charging

2.1. Transmission Network Use of System (TNUoS) charges recover the cost of building and maintaining the transmission system.[7] 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[8] that are above 100MW in capacity. Generation which is below 100MW on the distribution network ("smaller EG[9]") 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.[10] Currently this is based on net demand in a Grid Supply Point (GSP) group, where net demand is the gross or total customer demand on the distribution network, less any generation output from smaller EG, within each GSP group. As such, smaller EG is treated not as generation, but as 'negative demand'.[11] This means that smaller EG are often paid by suppliers to generate at triad (and sometimes directly by National Grid), to reduce the suppliers net demand on the transmission system, and therefore reduce their TNUoS charges. The cost of these payments from suppliers (or from

[7] An introduction to the transmission charging regime is available in appendix 1; connection charges are also paid by those connecting to the transmission system
[8] Referred to as distribution-connected generation, distributed generation or embedded generation.
[9] 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.
[10] The three half hour periods of highest transmission system demand between November-February, separated by at least 10 days.
[11] It therefore faces the inverse of the demand transmission charges. Because of the size of the TNUoS Demand Residual, these charges currently always result in payments to smaller EG.

National Grid) to smaller EG is recovered from consumers (explained further in 'problem definition').

2.3. 'Embedded benefits' refer to the different treatment in terms of transmission and balancing charges which smaller EG receive compared to larger (over 100MW) EG on the distribution system and transmission connected generators. The largest of these differences are the payments that smaller EG receive for helping suppliers[12] to avoid transmission demand residual (TDR) charges (or payments they receive directly from National Grid).

2.4. The table below sets out the main embedded benefits relating to transmission and balancing use of system charging[13]. 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. 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.

[12] During the CMP264/5 workgroups, National Grid estimated 7.5GW of smaller EG runs during winter peak periods. In addition, the more EG that is used to offset charges, the smaller the transmission demand charging base, which leads to higher user charges for other users.
[13] 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 and balancing use-of-system charges

Embedded benefit element	What is it?	Current value (2017/18)
TNUoS demand residual (TDR) payments	This is the largest embedded benefit. Smaller EG can receive these payments from suppliers or National Grid if they generate during triad periods.	c.£47.00/kW
TNUoS generation residual (TGR)	Smaller EG currently does not pay the TNUoS generation residual (as it is now negative, they are not paid this element in the way a transmission-connected generator would be).	c £-2.00/kW
TNUoS locational charges (demand and generation)[14]	Smaller EG that generates during triad periods (mainly non intermittent EG) are treated as negative demand and hence face the inverse of the demand locational signal. This provides similar signals to facing the generation locational signal. The differencesbetween the two signals vary by location and type of generation and are based upon: • the difference in charging bases, with triad for demand vs TEC for generation • different treatment of intermittent/non-intermittent generation • different zonal differentiation (27 generation zones vs 14 GSP Groups).	Demand locational charge varies by region and is currently (17/18) c.£-17 /kW to c. £8/kW Generation locational signal varies by region and technology and ranges from c.£-8/kW to c.£33/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[15] Equivalent to c£4/kW-c£17/kW assuming 20-80% load factor
BSUoS generation charge	Smaller EG currently does not pay the BSUoS generation charge	c£2/MWh Equivalent to c£4/kW-c£17/kW assuming 20-80% load factor

Definition of the issue

Our open letters

2.5. In July 2016, after the code modification proposals had been made, we published an open letter[16], 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[17], setting out the key developments since our July open letter, and providing an update on our views to

[14] The fact that smaller EG is treated as negative demand can provide both benefits and disbenefits compared to other forms of generation.
[15] BSUoS charges vary between £-0.23-£47.78/MWh depending on the settlement period. £2.54/MWh is an average across the 2016-/17 charging period.
[16] https://www.ofgem.gov.uk/publications-and-updates/open-letter-charging-arrangements-embedded-generation
[17] https://www.ofgem.gov.uk/publications-and-updates/update-letter-charging-arrangements-embedded-generation

market participants, particularly those bidding into the CM T-4 and early capacity auctions in late 2016/early 2017.

2.6. These updates, and the continued work on the issue of embedded benefits were part of our 2016/17 forward work programme[18] and are restated in our 2017/18 forward work program[19]. This is our impact assessment and decision on the CUSC modification proposals which have been submitted to us, and details the reasoning for our decision, along with an assessment of the likely impact of these changes.

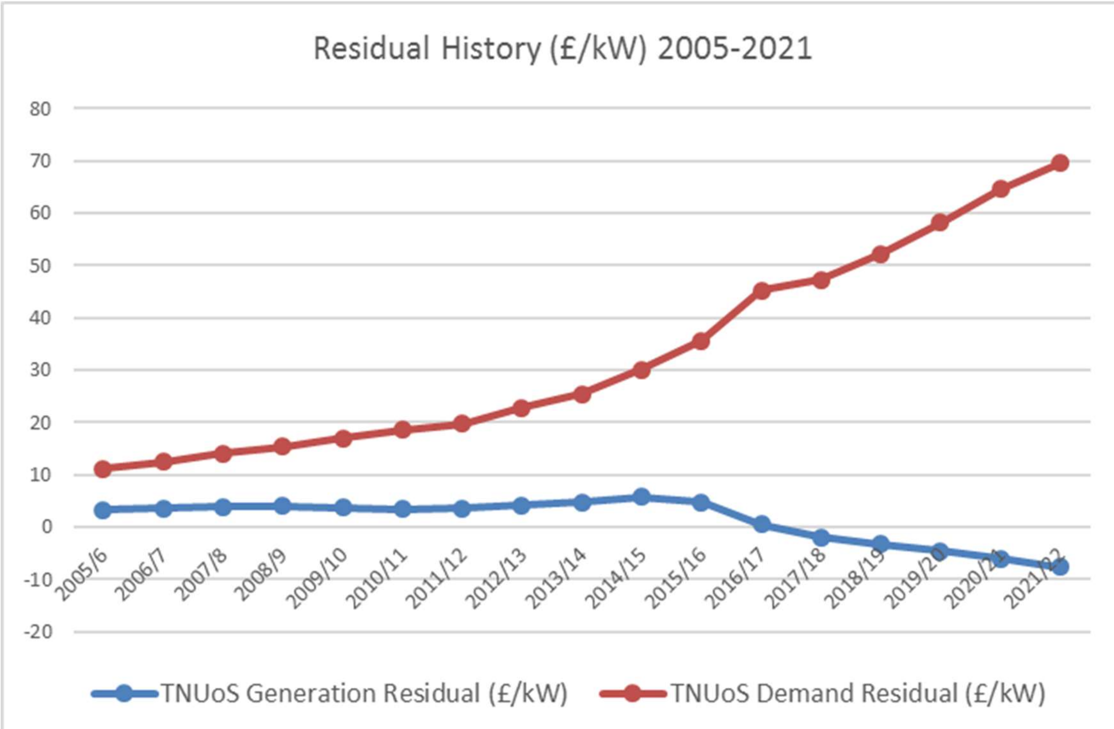
Problem definition

2.7. This section provides a high-level summary of issues around the TDR payments which smaller EG can receive.

2.8. Historically, total transmission charges were lower than they are today and the amount of smaller EG was smaller meaning that the distortions caused by the payments were also relatively low. However, both the number of smaller EG and the total amount of National Grid expenditure to be recovered through the TDR has increased in recent years. This combination has led to large TDR payments 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, alongside the evolution of the TNUoS Generation Residual (TGR).

[18] https://www.ofgem.gov.uk/publications-and-updates/forward-work-programme-2016-17
[19] https://www.ofgem.gov.uk/system/files/docs/2017/03/ofgem_forward_work_programme_2017-18.pdf

Figure 1 - Transmission residual charges



2.9. Currently the available TDR payment is c. £47.30/kW.[20] This is predicted to rise to £69.59/kW in 2021/22. To put the value of this in context, £47.30/kW is over double the latest Capacity Market (CM) clearing price[21] and the payment is made for generating 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[22] periods.

2.10. The payment of the TDR to smaller EG 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 periods. This leads to revenues that need to be recovered via the transmission charges being recovered over a smaller charging base. This increases the level of

[20] 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 smaller generator varies from c£29/kW to c£55/kW (2017/18 figures).
[21] CM auction in December 2016, for delivery in 20/21
[22] This contrasts with the arrangements for transmission connected generation where generators are paid (or pay) on their capacity whether they generate at peak or not (though SBR plant do currently need prove their ability to generate within the year).

the TDR charge, increasing charges to those who cannot take the same action and also increasing 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 periods.

2.11. We believe the size and increase in the TDR payment is leading to the following distortions[23] and outcomes:

- **Wholesale price** – By running out of merit, the wholesale market price is distorted and artificially dampened at peak times;
- **The Capacity Market** – Smaller EG have a competitive advantage[24] when bidding into the CM, reducing their possible bid prices;
- **Dispatch** – Increasing amounts of smaller EG generate out of merit to ensure they hit the triad periods;
- **Inefficient investment in generation capacity** – A large financial incentive to locate on the distribution system even in circumstances where it is not the most efficient place to locate, and to build generation capacity that may not have been efficient to build under a regime without these distortions;
- **Ancillary servies** – Smaller EG may be at a competitive advantage in the ancillary services market.

2.12. We believe the distortions outlined above lead to higher consumer costs. More efficient generators could be pushed out of the market, while consumers have to pay additional money to allow suppliers to 'offset' their transmission residual charges. As the amount of money recovered through TNUoS residual charges is largely fixed over the short to medium term, where these charges are avoided, they will have to be picked up by other users. In addition, TDR payments could lead to inefficient investment in network capacity. Inefficient investment in generation connected to either the transmission or distribution networks would lead to inefficient additional network investment, raising costs to consumers.[25]

2.13. Suppliers recover both the TNUoS charges and the cost of TDR payments to smaller EG from consumers, which increases the total costs recovered from consumers. We have received a significant number of responses to our consultation,

[23] We recognise that DSR and behind the meter generation will also have this impact also. We intend to look into these elements as part of our work on the residuals as part of the Targeted Charging Review.
[24] 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.
[25] Network costs, through additional transmission or distribution network investment are not modelled in our quantitiative modelling as new plant may use existing or recently decommissioned connections, or may not require significant network investment. The location of new plant can significantly impact the amount of new investment needed. Due to this unpredictability, the modelling would be very sensitive to input assumptions, and so network costs are not modelled.

though none lead us to believe that the current TDR payments are cost-reflective, sustainable or equitable.

The CUSC modification process

2.14. Two CUSC modifications, and their respective Workgroup Alternative CUSC Modifications (WACMs), were submitted to us for decision, which propose solutions to the issues discussed above. As discussed in Chapter 3, we can either accept one, reject all of the proposed options, or send the proposals back. The send back option may be used if, for example, further analysis is required by the workgroup, or we consider we are unable to form an opinion based on the information submitted to us.

2.15. 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 modifications are 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 2, but the essentials are set out below.

2.16. 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.

2.17. 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 or reflect relevant discussions within the workgroup process.

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

2.19. Finally, once the CUSC Panel have voted on the original proposals and the relevant WACMs, they will submit their recommendation to us, alongside the workgroup FMR. We will then make a final decision on whether to accept, reject or send back the proposals. We will make a decision with an assessment against the applicable CUSC objectives, as well as our wider statutory duties. For important decisions, such as this decision, we can undertake our own impact assessment and consultation before making a decision, 2.20. Some respondents to our consultation noted a number of concerns with the CUSC process, in particular for those parties who are not signatories to the CUSC. Having undertaken our own IA and consultation, and having received meaningful representations from a broad range of stakeholders, we are confident that we are in the position to make a decision on this matter. We are confident that our engagement with stakeholders on the contents of the consultation have been sufficient to allow for informed comment by stakeholders and the full consideration of stakeholder views by us as the regulator.

Output from the workgroups

The original CUSC modifications proposals and WACMs

2.21. 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.[26] Both of these modifications seek to prevent smaller EG from being able to receive payment related to the TDR charge, but would continue to allow smaller EG to recieve the inverse of the transmission demand locational signal.

- 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.

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

2.23. 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 a majority of the workgroup – 4 of these applied to both CMP264 and CMP265, with the other four addressing the defect under CMP264 only.

[26] 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/.

- 15 other 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.
- 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 outcome of the vote can be found in appendix 2.

2.24. All of the WACMs (and originals) put through seek to make changes to the TDR[27] 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, or for generators with and without CfD and CM contracts.

CUSC Panel vote

2.25. 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 panel vote is provided below, with further information available in the FMR and in appendix 2.

- **CMP264 –** WACMs 1-7 were voted as being better than the status quo, with WACM3 receiving the most votes.
- **CMP265 –** WACMs 1-7 were voted as being better than the status quo. WACMs3 and 5 received the most votes.

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

[27] Technically speaking, the modifications move to charging 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.

3. Options available to us

Chapter Summary

This chapter provides a full explanation of the options presented to us in the FMR presented to us by the 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 have made a final decision on the modifications within the FMR, and have taken the workgroup vote, the CUSC Panel vote, the evidence in the FMR, responses to the consultation on the minded to decision and our statutory duties into account. We have also taken into account the views received during numerous bilateral meetings with a range of stakeholders.

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, we have the following three options:

- **Accept** – We accept one of the options presented to us;
- **Reject** - We reject all of the options presented to us; and
- **Send back** – We 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, we do not have the option to make changes to the modifications submitted to us.

3.4. We published our minded to decision and draft impact assessment on 1 March 2017[28] which set out our initial view that WACM4 best facilitated the CUSC objective and was consistent with our statutory duties. The consultation period was 7 weeks, following requests for an extension to the initial period. In addition to the number of opportunities to comment presented by the industry consultations and our open letters, we have also carried out extensive stakeholder engagement including a workshop and bilateral meetings.

[28] https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-consultation-cmp264-and-cmp265-minded-decision-and-draft-impact-assessment

3.5. The Authority also has the option to reject the modifications and undertake a wider review of network charging. We believe the TDR payments to smaller EG constitutes a significant distortion between smaller EG and other generation and that prompt change is required.

3.6. 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 were submitted to us for decision.

3.7. A number of stakeholders have provided representations that a full review of network charging is needed, and feel that the issue of TDR payments can only be considered in the round as part of a wider review. Some respondents recommend taking no action at this point, or choosing an interim option that freezes the level of the payments or reduces it to a lower level while the Targeted Charging Review (TCR) or a similar review process is undertaken.

3.8. Some respondents to our consultation have suggested that the TDR payments should not be assessed until a full assessment of the forward-looking cost-reflective locational elements has been undertaken. For example, a number of respondents cited NERA[29] analysis that noted the level of costs recovered from the locational charges could be increased significantly under different arrangements. We note that NERA also state that up to 90% of the costs of networks are fixed. Where marginal costs are below average costs, cost recovery charges will be needed to recover total costs.

3.9. We recognise further development of the forward-looking locational charges may be merited and that proposals are progressing through the code governance process. Forward-looking signals should be designed to be reflective of the cost of incremental use so network users can make efficient choices. While we expect significant transmission residual charges for demand to be required under most revisions to the forward-looking arrangements, arrangements where payments, based on demand residual charges, are made to EG, represents a large distortion and harm to consumers. Through our future-focussed strategy work, we are considering whether other changes to network charging and access are needed. We propose to undertake any such work in parallel with the proposed TCR.

3.10. Others have suggested that there is potential for significant unintended consequences from taking action on TDR payments and so more analysis should be undertaken before action is taken. We have identified a very large distortion caused by the TDR payments to smaller EG. We have signalled our intention to look at other distortions which may arise from residual charging through the proposed TCR, and

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

this will reduce the risk that any consequences from changes to TDR payments are not understood and addressed where necessary.

3.11. We therefore continue to believe that addressing the TDR payments through a wider review would be unlikely to bring about the prompt change necessary to address this particular distortion, as such reviews can take a number of years before changes come into effect. We consider that earlier action on this particular issue is preferable due to the potentially lengthier timescales of an SCR (or another means such as an industry led review, as suggested by some respondents to our consultation), the scale and rate of increase of the TDR payments and the potential for further impacts on the CM and other markets. Incorporating this issue into the TCR could mean two further years of escalating distortive payments, meaning significant additional costs to consumers and two further years of distortion to CM auctions.

3.12. In addition to the consumer cost, distorted investment and dispatch signals are likely to lead to inefficient allocation of resources. This may hinder innovation by allocating resources to those parties who are able to access these revenue streams rather than those providing efficient innovative services that consumers want. The presence of non-cost reflective and distortive payments[30] is also bad for competition, as these 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 encourage efficient use of the system and attract generators to where they are most useful to the system. We have not seen evidence from workgroups or in response to our two open letters or to our consultation to support the current level of this differential treatment of smaller EG and other generators.[31]

Modification proposals and their characteristics

3.13. 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 value of ‘x’);
- The treatment of existing smaller EG, who may be receiving payments under the current arrangements;
- Transitional arrangements – both grandfathering and phasing; and
- Additional impacts.

[30] 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.
[31]These issues are discussed in more detail in chapter 4.

3.14. All of the CUSC modification proposals (and WACMs) that have been put forwardreduce the total TDR revenue that smaller EG can expect to receive compared to the 'status quo' scenario.

Features of the modifications and WACMs

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

- The locational signal[32]
- Flooring at zero
- Transitional arrangements – grandfathering[33]
- Transitional arrangements – phasing[34]
- A value of 'x' for either affected smaller EG, and/or grandfathered EG.

3.16. 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) and the TDR is recovered over gross demand. Smaller EG do not receive the TDR as payment but receive an explicit 'embedded export tariff' which is applied to smaller EG (or a subset of smaller EG) exports.

3.17. This proposed new embedded export tariff takes the form of a demand locational tariff[35], charged net (as now) plus a new value to replace the current TDR value. This element of the new tariff (replacing the current TDR payment to smaller EG) is referred to as the "value of 'x'".

The Locational Signal

3.18. 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 depending 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. Smaller EG are 'charged' according to their generation over the triad periods, so only

[32] Appendix 1 explains transmission charging in more detail and explains how they are composed of both locational elements, which reflects the relative locational difference in cost a generator has on the system, and the residual components, which recover costs after other charges are levied.
[33] 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.
[34] Phasing options involve a linear 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.
[35] 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.

face the charges if they are running at these times. Currently, due to the size of the demand residual, all smaller EG are currently paid if running at triad.

3.19. Smaller EG is seen as 'negative demand' within the GSP groups, 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 demand locational tariff is positive, smaller EG will be paid the locational signal that demand users would pay.

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

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

3.21. All of the WACMs and proposals, with the exception of CMP265 original and the "lowest locational" options, introduce a 'floor at zero' for the transmission charges which smaller EG could face. 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 periods within certain charging zones. This would create an incentive for smaller EG to not generate during triad period, which was seen in the workgroup as having both potential security of supply implications, and also revenue implications, as it was not clear how these charges could be recovered from non-CUSC signatories.

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

Transitional arrangements – Grandfathering

3.23. Some of the WACMs propose to grandfather a specific subset of generators – i.e. to maintain more favourable TDR charging and payment arrangements for a specific sub-set of smaller EG, whilst changing those arrangements for all other smaller EG. The WACMs that include "grandfathering" apply the arrangements according to whether the EG in question commissioned before a certain date, or whether they hold a CfD contract or a CM contract from the 2014 or 2015 CM auctions.

3.24. Most WACMs which propose grandfathering do so by providing for TDR payments for smaller "grandfathered" EG at £45.33/kW[36] until 2033, with the exception of WACM23 which would grandfather these payments at £34.11/kW[37] for 10 years.

3.25. The two original proposals (CMP264 and CMP265), however, propose that "grandfathered" EG continue to benefit from the existing TDR charging arrangements – i.e. net charging, resulting in continued TDR payments from suppliers that are likely to rise to c. £69.59/kW by 2021/22, according to National Grid's current forecasts.

Transitional arrangements - Phasing

3.26. Phasing aims to soften the impact of changes for smaller EG by reducing the level of TDR payments to smaller EG over a period of three years. The total reduction in TDR payments would be the difference between the current (2017/18) level and the final value of 'x' in the third year. In the first year (starting April 2018), the TDR payment level would be the 2017/18 level reduced by 1/3 of the total reduction in TDR payments, and in the second year (starting April 2019), the TDR payment level would be reduced by a further 1/3, and in the third year (April 2020), the payments would reach the final value of 'x'.

Values of 'x'

3.27. National Grid's allowed revenue, recovered through the TNUoS charges, is recovered partly from generation and partly from demand. The charges for generation and demand have both a forward-looking cost-reflective 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 after the forward-looking cost-reflective charges are levied. Suppliers and National Grid make payments to smaller EG which we refer to as 'TDR payments'. These payments largely help suppliers to reduce their TDR charges.

3.28. CMP264 proposes charging the TDR on a gross basis for demand for 'new' smaller EG. This has the effect of removing the TDR payment as an embedded benefit for new[38] 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 that is to be added to the inverse locational signal, and is applied to all smaller EG, irrespective of their location. Hence the value of 'x' will replace the TDR payments currently received by smaller EG. As it makes no

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[36] Being the value of TDR payment to smaller EG in 2016/17
[37] Based on an average of the TDR in recent years.
[38] 'New' EG is defined in CMP264 as smaller embedded generation which commissions after 30 June 2017.

additional payment to smaller EG, CMP264 effectively has an 'x' value of £0/kW for new smaller EG.

3.29. The value of 'x' is the level of payment that would replace the current TDR payment. In some cases, it was specifically linked to the measure of benefit that a smaller EG will bring in terms of avoided transmission costs. The different views on what this this value of 'x' should ultimately be, led to a wide range of WACMs, with it ranging from £0/kW (meaning that smaller EG would just receive the inverse of the demand locational charge) to £45.33/kW[39] (freezing at the level they received in 2016/17).

3.30. Below is an explanation of the values of 'x' in the WACMs which were submitted to 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 further 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 one or more of the avoided GSP investment cost, TGR and the lowest locational value.

[39] Please note that throughout this document nominal figures are used for charges, but 2016 real figures are used in the modelling, in discussion of the present values presented by the modelling, and the graphs that depict this modelling.

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 demand locational signal
Avoided GSP investment cost (last estimate £1.62/kW)	Smaller EG will get the value of National Grid's calculation of the average cost of GSP reinforcement which is saved by embedded generators
Generation Residual (TGR)	Smaller EG face the value of the TNUoS generator residual charge which transmission generators and over-100MW generators would pay/be paid
Generation Residual (TGR) + 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[40] (£18.50/kW) and the avoided GSP investment cost (£1.62/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 locational signals between charging zones.
£27.70/kW for 5 charging years then Generation Residual (TGR)	£27.70/kW is the value at which the TDR payment was at when embedded benefits were last considered in 2013/14 in the National Grid 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 was in 2016/17, to prevent further increase.

Value of 'x' – Avoided GSP investment cost

3.31. 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[41] in 2013/14, where the average annuitized cost of the infrastructure reinforcement was taken from a number of projects, and divided by the average capacity delivered by a supergrid transformer (the cost of the supergrid transformer

[40] http://www.theade.co.uk/medialibrary/2016/05/16/09ca4432/A%20review%20of%20Embedded%20Generation%20Benefits%20in%20Great%20Britain.pdf.
[41] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=32765

is not included). This provided a unit cost of the avoided infrastructure reinforcement at the GSP, last calculated as £1.62/kW in 2013/14 prices.

3.32. Options which include the avoided GSP investment cost as a value of 'x' include proposals to update this figure prior to any implementation and at the beginning of every price control[42] (with RIIO infrastructure costs).

Values of 'x' – TNUoS generator residual

3.33. Historically, the residual components of the transmission charges have always been positive. However, the TGR charge, due to a number of factors[43], is now negative, meaning that transmission, and over 100MW EG, 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 result in smaller EG being paid the value of the negative generator residual charge, in the same way as transmission and over 100MW EG would. It also means that, if the generation residual charge returns to being positive, some smaller EG would have a reduced benefit. However, 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.

Value of 'x' – Lowest demand locational value

3.34. 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.

3.35. 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 and not generate, as they would be required to make a payment. This option prevents the need for a 'floor at zero', but does introduce a link between the value of embedded benefit and the lowest locational value. As a result, if the locational

[42] The avoided GSP is represented in the legal text as the Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer. The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent schemes submitted under the price control process and indexed each year by an RPI formula until the end of the price control.
[43] The generation residual has recently turned negative due to a cap of €2.50/MWh on the charges that can be applied to transmission connected generation.

signals are changed, the level of payment to embedded generators will change too, in a way that may not be reflective of additional benefit.

Value of 'x' – Removal of offshore costs

3.36. 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 above £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 solution was considered to be outside of the scope of the workgroup and was instead developed into an option where a tariff for smaller EG was calculated, equivalent to what the TDR would be with offshore costs removed.

Summary of value of 'x' options

3.37. The table below sets out the key features of all of the WACMs (and originals) presented to us 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 periods.

Table 3 - Key features of the proposed modifications

WACM Number	Affected Generator Value of 'X'	Affected Generator	Grandfathered Generator	Level of Grandfathering	3 Year Phasing
264 Original	£0/kW	All commissioned after 30/06/17	All commissioned before 01/07/17	Net charging retained	N
WACM 19	£0/kW	All commissioned after 30/06/17	All commissioned before 01/07/17	£45.33 + RPI until 2033	
WACM 20	£27.70/kW for 5 charging years then Generation Residual	All commissioned after 31/10/18	All commissioned before 01/11/18		
WACM 21	Lowest locational value	All commissioned after 31/10/18	All commissioned before 01/11/18		
WACM 22	£0/kW	All commissioned after 30/06/19 and multiyear-new build CM/CFD contracted after 14/15	All commissioned before 30/06/19 excluding multiyear-new build CM/CFD contracted after 14/15		

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

WACM 17	£32.30/kW				
WACM 18	Demand residual with offshore costs removed				

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

3.38. There are four other modifications which go alongside CMP264 and CMP265 and enable the implementation of the modification proposals.

3.39. 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 to section 11) and so CMP269 and CMP270 were raised to enable these changes and will be assessed against the non-charging objectives. Both CMP269 and CMP270 have the same proposed solution.

3.40. 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 between Elexon and National Grid, so that both CMP264 and CMP265 can be implemented and TNUoS tariffs can be calculated.

4. Assessment of options against decision making criteria

Chapter Summary

This chapter sets out our qualitative assessment of the options presented to us against the applicable CUSC objectives and our statutory duties, and in doing so, refines the number of options for further consideration.

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[44] as compared with both the status quo and also any alternative modifications put before us in the FMR; and
- the modification is consistent with our 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.

4.3. In the following section we undertake a principle-based assessment of each of the modification proposals' suggested value of 'x' and implementation methods against the CUSC objectives. Next we assess the objectives against the our statutory duties, we then shortlist the options for detailed assessment.

4.4. When undertaking our principle-based assessment, we have compared each component to the status quo to assess whether it is better that the baseline. We

[44]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

have then assessed these options to consider which proposals are most likely to best facilitate against the CUSC objectives and be consistent with our Statutory Duties.

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 (b) - Cost-Reflective Charging

4.5. This section explains our assessment of the cost reflectivity of the modifications and WACMs under consideration. This provides an assessment of whether the various values of x proposed in the modification are more cost reflective than the level of TDR payments that would be made under existing TNUoS charging arrangements.

Value of the payments to smaller EG

4.6. While a large number of modification proposals are available, there are only a relatively limited number of alternative proposed values of 'x'. As set out in Chapter 3, the key options for 'x' are the (i) avoided GSP cost, (ii) the generation residual, (iii) the value of the TDR payments at various points in the past; (iv) values based on

Cornwall's analysis[45] of the transmission cost savings associated with embedded generation; (v) TDR excluding offshore costs and (vi) the lowest demand locational.

4.7. The principle of cost reflectivity enshrined in CUSC objective (b) means that users who use the transmission network should face charges that broadly reflect the costs that they could impose on the network as a result of their future decisions. Cost-reflective charges are important as they allow market participants to make efficient investment decisions taking into account the impact that they have on the transmission network[46]. This helps develop an economically efficient transmission system. Similarly, where payments are made to transmission network users through negative charges, these should reflect the cost savings (or benefits) that the system derives from those network users. A lack of the appropriate price signals is likely to lead to inefficient generation and network investment.

4.8. The transmission locational charges are designed to provide forward-looking cost-reflective signals to network users so that they connect and use the network efficiently. The demand and generation residual charges are designed to ensure total allowed revenues (as allocated between generation and demand) are recovered after the forward-looking charges are levied. (Due to the current cap on transmission charges for generators, the TGR charge is currently negative.) Suppliers and National Grid make payments to smaller EG which we refer to as 'TDR payments'. These payments largely help suppliers to reduce their TDR charges.

4.9. Economic theory indicates that residual charges should be set in such a way to prevent the signals from the forward-looking charges from being distorted, so that users take account of the forward-looking signals to the greatest extent possible. We are concerned that the TDR payments are distorting the signals from the forward-looking charges, and hence undermining the cost reflective element of the charges since:

- these payments arise from the TDR charges which are largely intended to 'top up' transmission demand charges to ensure allowed revenues are recovered; they are not designed to provide signals to encourage behaviour

- while a small element of these payments can be related to savings at GSPs that smaller EG can provide, the scale of these payments do not

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

[46] 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.

reflect benefits provided by smaller EG to the transmission network, and hence these payments are not cost-reflective; and

- they are creating incentives for greater quantities of smaller EG to connect on the distribution system, in order to obtain these payments, This is a significant distortion that is increasing costs to consumers.

4.10. Our final view is that the current TDR payments made by Suppliers and National Grid to smaller EG are not cost reflective - as the payments do not reflect the savings in transmission system costs attributable to smaller EG. We would also note that options that provide grandfathering at the 2016/17 level of the TDR payment, or similar level of TDR payments, to certain smaller EG are not cost reflective and guarantee the non-cost reflective level of payments for extended periods. This is also true of phasing, but the non-cost reflective payments are retained for a much shorter period than in the case of grandfathering.

4.11. We assess the justification for the different proposed payment levels against CUSC objective (b) in the next sections.

Avoided GSP investment

4.12. Our final assessment is that avoided GSP costs are the only benefits to the transmission system that have been robustly demonstrated to flow from smaller EG. A value of 'x' equivalent to avoided GSP costs would reduce the TDR payment to one which reflects long run cost savings achievable on the system from the reduced need to reinforce the points where the distribution system meets the transmission system[47].

4.13. Analysis produced by Engie for the CMP264/265 workgroups and included as a supporting document with the CMP264/265 FMR[48] suggested 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 section of the network that connect the transmission and distribution networks. This assessment is based on load flow analysis of the effect on the transmission system of transmission- and distribution-connected generation at the same GSP, using the current version of National Grid's transport model.

4.14. According to the presentation, the analysis "shows that identical flows result from connecting generation at either the transmission or the distribution level." The analysis suggests that for a model system[49], adding 450MW generation either to the distribution or transmission system resulted in exactly the same change in

[47] This may not be the case where a GSP is exporting
[48] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937458
[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)

transmission system network size (both reducing the size of the network by around 0.5%).[50]

4.15. If this analysis is correct, 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).

4.16. Respondents to our consultation have provided examples that show that the addition of smaller EG gives different results in the transport model (in MWkm) than those workgroup examples that suggested EG was identical to TG. We have reviewed these concerns and note that this is due to the models differential treatment of EG as negative demand, rather than any beneficial characteristic of smaller EG.

4.17. When treated as negative demand rather than generation, EG is not scaled by a scaling factor (as set out in the SQSS[51]) as other generation would be. This means that removing the generators' capacity from demand by netting off their output with the demand from the area will have a full, unscaled impact on the system. This can have a bigger impact on the modelled system because that demand reduction "goes further" than the corresponding generation increase, as it is not scaled. We disagree this is evidence of EG's benefits, and note that it is no different than other generation. It is the differential treatment via the model that leads to the different result.

4.18. The locational charges have a broad relationship with the investment needs that underpin the system and are defined in the SQSS. The SQSS is not concerned with how residual costs should be recovered or charged. These should be recovered on economic principles in a way that reduces distortions.

4.19. Further, National Grid's 2013/14 embedded benefits review[52],[53] established that the cost of GSP infrastructure investment is an evidenced cost that embedded generation can help to avoid. Throughout the entire process we have seen little evidence that a value of 'x' above this level this would be reflective of system savings attributable to EG.

4.20. The National Grid 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*

[50] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937458, page 4.
[51] Security and Quality of Supply Standard (SQSS) sets out the criteria and methodologies for planning and operating the GB transmission System.
[52] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/
[53] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=29996

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."

4.21. The average annuitized cost was determined to be £1.58/kW in 2012/13 prices, but later adjusted to be £1.62/kW. The value of avoided GSP infrastructure investment was derived from eighteen reinforcement schemes assessed from the RIIO-T1 price control submission, with annuitised costs ranging from a few pence/kW to £4/kW. A number of stakeholders noted that the modifications taking these costs into account use a figure that has not been recently updated, and was based on a limited number of schemes. We have discussed the potential for revised levels with National Grid and understand that they will be updating this analysis before the implementation of this modification. We have also included sensitivity modelling on the impact of a higher level of avoided GSP payment as part of our quantitative analysis.

4.22. A National Grid chaired embedded generation benefit focus group was held in May 2013 with a range of industry parties, where National Grid presented their evidence that avoided GSP costs attributable to EG could be recognised in most GSPs, though not necessarily in exporting GSPs[54] (as in these GSPs there would be additional flows across the GSP infrastructure). We recognise that those options that take avoided GSP costs as the value of 'x' do not differentiate between GSPs based on their location or whether they are exporting to the transmission system. These options set the value of 'x' for *all* smaller EG at the average level of the avoided GSP cost regardless of whether a given EG is in an area where GSP costs can be saved by EG. This will inevitably compensate some generators for a benefit that they aren't providing and continue to offer signals to generate when this might not be the right signal. Taking the average value of avoided GSP costs as the value of 'x' for all generators is, however, more cost reflective than (i) the current TDR payment arrangements and (ii) the alternative options for the value of 'x' available on the other modification proposals before us.

4.23. In light of the above, our final view is that a value of 'x' equivalent to the avoided GSP costs is the one that has been most robustly justified as cost reflective.

4.24. A number of the modification proposals before us provide for a value of 'x' equivalent to avoided GSP costs. These are in our view, the more cost reflective options compared to the status quo. They replace the current TDR payment with an evidenced payment with a value of 'x' that 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, because it more accurately reflects the cost savings that are achievable it is less likely to undermine

[54] 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 at times, resulting in distribution systems exporting power onto the transmission system. These areas are referred to as exporting GSPs.

the locational signals; moreover, it is possible that future changes could investigate the merit of locational variation in these payments.

4.25. A number of respondents to our consultation noted that the methodology for calculating the avoided GSP costs excludes the cost of supergrid transformers[55], and noted that the Transmission Owners (TOs) can receive additional revenues under the RIIO framework for each supergrid transformer installed. This subject was the focus of some discussion in the workgroup, and these costs were excluded from the methodology for calculating avoided GSP costs because supergrid transformer costs are recovered in part from the DNOs, and in part through connection costs, and not through transmission charges.

4.26. It was also noted that load-related volume drivers within RIIO provide £/kW values for the cost of infrastructure build. Some respondents have suggested that embedded generators can prevent the requirement for these transmission upgrades, therefore, they should be paid an annuitised value of those infrastructure upgrade costs.

4.27. We would note that while the TOs, so far, have outperformed their load-related volume drivers, having not built the level of generation/demand connections forecast in their RIIO baseline, we are only 3 years into the price control and it is difficult to link the underspend directly with increased embedded generation. We therefore think that there is not currently sufficient evidence of a direct causative link between embedded generation and reduced expenditure on transmission assets beyond that of the GSP infrastructure savings.

TNUoS Generation Residual (TGR)

4.28. As a cost-recovery and reconciliation element, the TGR is not designed for cost reflectivity, but for the recovery of allowed revenues not recovered by the generation locational charges. The main arguments for exposing smaller EG to the TGR are made on competition, not cost reflectivity grounds and are as such addressed in our consideration of CUSC objective (a).

Payments based on historic levels and Cornwall Energy estimates

4.29. A number of proposals set the value of ‘x’ at historic TDR levels and are intended to provide a degree of continuity of revenue for smaller EG. These levels do not reflect the benefits to the transmission system attributable to smaller EG. To the extent that these values of ‘x’ are closer to the avoided GSP costs, rather than being based on the level of the TDR as in the status quo scenario, these values of ‘x’ can

[55] This is a costly TO asset that is used to step down voltage from transmission voltage to distribution voltage.

be said to be more cost reflective than the status quo. However, those values of 'x' would be less cost reflective than a value of 'x' set at avoided GSP costs.

4.30. A number of modification proposals use values of 'x'[56] based on Cornwall's analysis on the avoided transmission infrastructure cost brought by smaller EG.[57] Cornwall Energy's analysis suggests that EG can generate transmission system reinforcement cost savings beyond avoided GSP costs. However, the Cornwall analysis proceeds on the basis that EG can save costs that have already been incurred, which is not feasible. In addition, we think the Cornwall estimate of savings available is flawed.

4.31. Cornwall Energy's analysis states that 1MW demand reduction should be charged in the same way as a 1MW increase in embedded generation. We agree that under the current arrangements, from a forward looking transmission perspective, a unit of demand reduction (at a given point on the distribution network) could have the same implications as a unit of distributed generation. Therefore, when the current cost reflective charges (such as the TNUoS demand and generation locational) are being considered or applied, it would be reasonable to charge/compensate equally for one more unit of EG and one less unit of demand. On the other hand, for charges which are principally designed for cost recovery (such as the TDR), 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. As most of the costs to be recovered can't be avoided in the short to medium term, the aim in setting cost recovery charges is to minimise distortion. An additional unit of generation cannot reduce the historic costs of the transmission network, though it can reduce marginal costs of running the network.

4.32. Cornwall Energy'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.

4.33. The analysis assumes that EG offsets transmission investment on a one for one basis. We do not agree with this assumption and note that EG connecting in areas with high transmission costs or exporting GSPs may be driving increased transmission investment. 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 its costs are reflected in the locational charges that these generators face. It is the location of

[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.

these generators that drives the investment, not the voltage at which they are connected.

4.34. The Cornwall Energy 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.

Exclusion of Removal of offshore costs

4.35. Options that provide for a value of 'x' equal to the value of the TDR with the offshore costs removed are not cost reflective, in that they do not reflect the benefit that the system derives from smaller embedded generators. They do function to reduce the level of TDR payments to EG as compared with the status quo and as such can be said to be more cost reflective that the baseline. However, with the payments expected to rise to above of £50/kW by 2021, a value of 'x' that excludes offshore costs only is unlikely to significantly address the distortions associated with the current TDR payments arrangements identified in Section 3 . Such options also retain a link between the TDR (albeit with the offshore costs removed) and the value of embedded generation. As the TDR is predominantly a cost recovery charge to ensure allowed revenues are recovered, EG cannot reduce these costs as these investments cannot be unspent. There is therefore no justification for paying the TDR, with or without offshore costs removed, to EG.

The 'floor at zero' and lowest TNUoS demand locational methods of preventing disincentives to generate at peak periods

4.36. 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 potential 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 when compared with the using the lowest locational to avoid the disincentive to generate at triad, but is worse than the lowest locational when considering the preservation of locational signals within the EG sector. The 'floor at zero' may cause large embedded benefits in certain zones, and also has the potential to lead to interactions with the TGR that may further increase the embedded benefit if the TGR was to again become positive.

4.37. 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

[58] Described in full in appendix 3.
[59] Also described in full in appendix 3.

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. Neither is it cost-reflective for two generators either side of a GSP, one transmission connected and one distribution connected, to face signals that differ by more than the costs that can be saved through avoided GSP reinforcement.

Overall assessment of impact on cost-reflectivity

4.38. This table sets out our final assessment of whether each of the values of 'x' proposed in the modification proposals 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 many 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 4 - Assessment of cost-reflectivity of values of 'x' (payment level)

Cost-reflectivity			
Payment level	**Examples**	**Cost-reflectivity**	**Compared to Status Quo**
£0	264	Does not include identified benefits of EG	Better than status quo
Avoided GSP	WACMs 3, 4, 13	Supported by NG 2013/14 review, well supported by evidence	Better than status quo
Avoided GSP + Gen residual	WACMs 5, 14	Avoided GSP supported by NG 2013/14 review, Generation Residual not a cost-reflective payment	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	Better than status quo
Status quo	265, Status Quo	Not cost-reflective	Neutral

*Use a combination of levels

†Grandfathered at historic level

4.39. Overall, the modifications that we consider likely to best facilitate this objective are those in which the value of 'x' is set at the cost of avoided GSP investment. This payment recognises a benefit of smaller EG versus transmission-connected generation, and will be updated at implementation and at the beginning of each price control with the forward-looking benefits of EG.

CUSC Objective (a) - Facilitating Competition

4.40. In the section, we assess whether each modification before us is better, worse or neutral in terms of facilitating competition than the status quo. To do this, we have considered 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 TGR
- 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 some smaller EG
- Whether and how the options use phased implementation

4.41. Below, we discuss each of these factors in turn. After doing this, we set out our final 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')

4.42. We consider that competition between generators will best flourish under charging arrangements that are non-discriminatory[60] and create a level regulatory playing field; in other words, charging arrangements that expose similar generators to the same sorts of charges and give them access to the same revenue streams under similar conditions. 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 uneven playing field, if not justified, may hinder competition by encouraging construction and dispatch of comparatively less efficient generation and thereby ultimately increasing consumer costs.

4.43. Smaller EG are currently treated differently to larger generators and can receive TDR payments if they generate over the triad periods. Larger generators cannot access this revenue. This differential access to potential revenue streams cannot be justified

[60] Discrimination can and should occur on the basis of cost-reflectivity, where those costs can be altered by future behaviour of the network user. This is distinct from the TDR payments where discrimination is occurring with little cost-reflective rationale.

by the difference in impact of smaller EG and other generation on the transmission system. The TDR payments do not reflect the costs or savings that actions by smaller EG bring to the network.

4.44. From the evidence presented to us, we consider that the benefit to the transmission network provided by smaller EG as compared to transmission generation is limited to the avoided cost of GSP infrastructure. Additional potential benefits suggested by stakeholders have not been sufficiently well demonstrated to warrant EG access to additional revenue streams above the level of the avoided GSP. We would therefore expect that any modification that reduces the value of 'x' to nearer to the level of avoided GSP costs as likely to deliver improvements to competition relative to the status quo; with options that reduce the value of 'x' to that precise level best facilitating competition out of all the options before us.

4.45. All of the modification proposals presented to us limit or reduce the level of TDR payments to smaller EG (i.e. the value of 'x') 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 for smaller EG will reduce. Those WACMs that retain the TDR with offshore costs removed provide the least improvement. While there may be some modest reductions, payments to smaller EG under this option are still expected to rise to above £50/kW by 2021. It is worth making clear that there is a clear link to cost-reflectivity in these considerations, with the level of the avoided GSP costs providing the best basis for a cost-reflective arrangement. Where payments are closer to the cost-reflective level, they will be better for competition. Where they are further from the cost-reflective level, they are likely to be worse for competition.

Options including the TNUoS Generation Residual

4.46. A number of options expose[61] smaller EG to the TGR, a cost-recovery charge. The TGR is now negative, and it has been argued that exposure of smaller EG to the negative TGR will prevent a situation where larger generators receive revenues that smaller EG cannot access.

4.47. Taking account of relevant differences, allowing smaller EG to access the same potential revenues streams as other generation would likely be beneficial to competition. The proposals put to us, however, mean that WACM 5 is likely to bring 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. This is because:

- The TGR would be paid on a triad (not TEC) basis, and therefore act as a further distortive incentive for smaller EG to run at triad period.

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

- The floor at zero element to the modification means that if the TGR returns to a positive charge, it will dampen locational signals seen by smaller EG. If the TGR were to increase to a figure above the highest locational charge, smaller EG would face no locational signals.

- The flooring elements also leads to asymmetric distortions. The TGR payments/charges to smaller EG would be the same across generators type when the TGR is negative, but would effectively act as an embedded benefit when positive.

4.48. The fact that WACM 5 would expose smaller EG to the TGR in a fundamentally different manner to other forms of generation due to the 'floor at zero' arrangements, reduces the extent to which the inclusion of the TGR would improve competition.

4.49. Some respondents to our consultation agreed that there was an argument that smaller EG should be exposed to the TGR payment as the payment of negative residual charges could act as a benefit to TG over smaller EG. We have carefully considered these arguments and consider that the proposals before us, which would expose EG in some locations only to the upside of a negative generation residual but shield them from the downside of a positive generation residual, have not been demonstrated to better facilitate competition than the present situation in which EG are not exposed to the generation residual (under or downside) at all. We think that the treatment of the generation residual should be reviewed as part of the TCR.

Options to prevent disincentives for smaller EG to generate at peak periods

4.50. 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.[62]

4.51. 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 a disincentive to run at peak time. Based on the tariffs for 2017/18, under the 'floor at zero' option for avoided GSP, seven zones have tariffs adjusted by the 'floor at zero'. The lowest demand locational option aims to remove the disincentive to run at peak times by providing smaller

4.52. EG with a payment that is equal to that year's lowest TNUoS Demand Locational (~£22.50/kW in 2020/21, though the figure varies each year). This preserves the geographical differences in locational signals within the smaller EG market better than the 'floor at zero' options (improving competition between smaller EG) but also preserves a greater level of payment to smaller EG when compared to larger generators. The 'floor at zero' provides less of a competitive

[62] These options are set out in more detail in Appendix 3

distortion between smaller EG and other generators but it dampens the geographical signals faced by smaller EG.

4.53. One respondent to our consultation suggested that neither of these option should apply, but we see merit in preventing disincentives on generating at peak periods. We think that both options have advantages. We note that options that include the lowest locational element introduce a significant risk of higher, non-cost reflective embedded benefits for all EG regardless of location if the locational signals are strengthened. In the future the 'floor at zero' could lead to higher embedded benefits to EG in some zones if the locational signals are altered, but this represents a smaller distortion than under options using the lowest locational. Of the two options, the 'floor at zero' option therefore appears, on balance, to be better for competition between all generators as it removes the bulk of the distortion between smaller EG and larger generators, and the new locational distortion added by the floor is relatively small in scale.

4.54. A number of respondents to our consultation have suggested that WACM7 (which takes the lowest locational as the value of 'x') would serve as an interim measure (that would address much of the distortion) and allow the wider TDR embedded benefit to be included in the Targeted Charging Review. However, we would not adopt an interim solution if we considered there was an option which better facilitated the CUSC objectives and met our statutory duties.

4.55. As we note above, there is no cost reflective link between the level of the locational charge in the zone where the signal is most strongly negative and the system-wide benefit. Further, a link between the lowest locational signal and the value of 'x' means that changes in the strength of locational signals will alter the overall payment to smaller EG, with no cost-reflective driver.

Options which include grandfathering of existing payments to smaller EG

4.56. This section assesses the impact of grandfathering (as per the modification proposals submitted to us for decision) and whether grandfathering is better, worse or neutral in terms of facilitating competition relative to the status quo and to non-grandfathering options. (Note: the impact of reduced TDR levels between options is considered separately in the section above, and is not taken account of here.)

4.57. 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.

4.58. The grandfathering options which have been presented to us all include i) the locking in of the TDR payments at fixed levels for the grandfathered smaller EG and ii) the immediate move to a new TDR payment level for all other smaller EG. These proposals improve competition between larger generators and smaller EG relative to the status quo, since the level of TDR payments to both grandfathered and non-grandfathered smaller EG are lower in these options than in the status quo.

4.59. However, grandfathering options maintain a distortion of competition between grandfathered EG and other generation. They also 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. One respondent has suggested that grandfathering would lead to a reduction in consumer costs once costs of replacement CM capacity to replace any non-delivery and a 1% increase in hurdle rates[63] for EG is taken into consideration. Our quantitative modelling section discusses these concerns in more detail, and we do not think that there is conclusive evidence to support such an increase in hurdle rates.

4.60. It has not been suggested to us, either before the consultation or as part of the responses to our consultation, 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.64 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. As any network charging revenue is inherently subject to change by the code modification process, change to network charging revenue as a result of this proposal (that uses that industry-led CUSC modification process) could not constitute unlawful interference with rights to receive revenue as no such rights can exist from a network charging regime that is subject to change. 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 changes65 to charging arrangements and to develop their business accordingly.

4.61. Generators, including CM/CfD holders, would have estimated future revenues and costs and set their CM/CfD bids accordingly. We cannot ascertain what proportion of smaller EG that have secured CM contracts and CfDs have 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 the TDR payments available at the time that the contracts were concluded to continue in perpetuity. 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. [66] 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

[63] The minimum rate of return required by a firm to undertake an investment.
[64] One respondent suggested that the review carried out by NGET in 2013/14, which concluded that no changes should be made to embedded benefits at that time, could amount to such an expectation. However, this was not a statement by Ofgem; neither did it provide any assurance that embedded benefits would not be reviewed in the future.
[65] Such changes would only be permitted or undertaken where they were in line with the requirements of the statutory scheme.
[66] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267649/Generic_CfD_-_Terms_and_Conditions__518596495_171_.pdf

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. [67]

4.62. We do have concerns that options that leave existing TDR payments in place for a subset of smaller EG and not others leave a distortion in place between the grandfathered smaller EG on the one hand and larger generation on the other hand. They also introduce a new distortion between those smaller EG who benefit from grandfathering and those who do not. These payments may mean that grandfathered smaller EG are not exposed to the same competitive pressures,[68] don’t respond to the same market signals,[69] or provide services for which they are not the most efficient provider. This could prevent some less efficient plant from exiting the market and more efficient plant from entering.

4.63. One respondent to our consultation has suggested that without grandfathering, they will be at a competitive disadvantage against other plant which bid into later CM auctions and are able to benefit from (potentially) higher CM clearing prices. They claim that consumers will experience ‘double benefit’ at their expense, since consumers will benefit from the lower CM clearing prices in the CM14/15 auctions (which are, in their opinion, based on EG expectations about higher TDR payments) and then also benefit because these TDR payments are then reduced for future delivery years. It has been suggested that this constitutes a “double benefit” to consumers and a “double loss” to these EG investors.

4.64. We consider the “double benefit, double loss” argument is a potential investment risk that may have arisen from an over-reliance on revenue streams that are subject to change through an industry code change management process. We would also note that some smaller EG clearing in the auction and gaining CM contracts may have meant some other generators that would otherwise have cleared did not do so. We do not think grandfathering would be appropriate as it would shift investment risk on to consumers, which would result in a further transfer from consumers to investors in smaller EG.

4.65. We have concerns that the introduction of a distortion such as grandfathering in a sector that is rapidly changing (due to technological developments) could be harmful to innovation, if they prevent the exit of plant that otherwise should exit the system, hindering the development of competition. In addition, options that include grandfathering would require an immediate change, to a lower value of ‘x’, for those generators that are not covered by grandfathering, as the availability grandfathering

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

[68] 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.

[69] This will potentially increase costs for consumers.

options do not include a phased transition for non-grandfathered parties. This would mean rapid change for those operators that are not covered by the grandfathering provisions, which could add some additional unpredictability in dispatch (though this may be limited when compared to dispatch uncertainty from other areas). The options available to us include grandfathering of current arrangements for 10-15 years.

4.66. In light of the above, we consider that modification proposals that reduce the value of 'x' closer to the level of avoided GSP costs would better facilitate competition than the status quo even where they provide for grandfathering certain types of EG that have already been built or committed to be built. However, we consider that, all other things equal (e.g. value of 'x' is the same) the options that do not provide for grandfathering better facilitate competition than the options that do.

4.67. We consider that proposals which include fixed cut-off dates for grandfathering in the future (i.e., those which keep in place the current arrangements until July 2019) are likely to be worse in terms of facilitating competition than the status quo, even where modification proposals reduce the value of 'x' closer to the level of avoided GSP costs. 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.

Options which include a phased implementation

4.68. A number of options available to us including a phased implementation period. This is a transitional arrangement where the new level of payments to generators is reduced over three years.[70] 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.

4.69. As discussed in the sections above, our 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 limited to 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[71] but for a shorter period than grandfathering, with the distortions reducing over the transitional period. In contrast, grandfathering includes much more significant revenues over a longer period, and is limited to one subset of users rather than all TDR recipients. It

[70] 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.
[71] As described in footnote 13 above.

also introduces a new distortion between grandfathered and non-grandfathered embedded generators.

4.70. We think that in this particular situation, phasing is justified due to the scale of the changes. Allowing a gradual introduction of this significant change will provide time for generators and investors to adapt their dispatch and business models. 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. Some respondents to our consultation considered options including phasing to be less likely to best facilitate the code objectives, as they would lead to a longer period of distortion. We think that the benefits of a phased approach in this case are likely to outweigh these considerations. Some respondents to our consultation have suggested that a longer periods of phasing would be preferable. We have evaluated the option of accepting WACM4 with a one year delay in order to assess the implications of a longer implementation period.

4.71. Our final view is that, all other things equal, both immediate and phased implementation routes would better facilitate competition relative to the status quo. However, we also consider that phasing has a number of advantages over immediate implementation. Phasing was generally well-received by respondents to our consultation.

Overall assessment of impact on competition

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

Table 5 - Overall assessment of impact on competition

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

4.73. Overall, it is our final view that CMP264 original, WACMs 1-19, and 23 would lead to an improvement in competition. CMP265 is likely to be neutral against the objectives. WACMs 20-22 are likely to be worse than the status quo because the associated deferred grandfathering arrangements incentivise construction of additional specific smaller EG to take advantage of the favourable levels of TDR payments.

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

General remarks

4.74. Our final 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 would help to achieve a more level playing field. 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 to this objective.

CUSC Objective (d) - Taking account of European Legislation

General remarks

4.75. Article 14 of EU Regulation 714/2009[72] 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, as these payments are 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

4.76. 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. Overall, and on balance, we feel the modification are considered neutral to this objective.

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

Overall assessment against all CUSC Objectives

4.77. We have considered each option against all of the CUSC objectives.

4.78. Of the options available, our final view is that WACMs 1-10 better facilitate the CUSC objectives. We also think that CMP264, and WACMs 11-19 and 23, on balance, better facilitate the CUSC objectives, despite their performance against objective (e) and that the recognition that grandfathering in these options retains the existing distortion between a subset of smaller EG (those with 14/15 CM contracts or CfD and all other smaller EG. CMP265 is on balance neutral against the CUSC objectives. We think that WACMs 20-22 do not better facilitate the CUSC objectives.

Table 6 - Assessment against CUSC Objectives

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

Compatibility with the Authority's statutory duties

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

4.80. Ofgem's statutory duties[73] 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 or transmission systems. This means making an overall judgement that takes into account a number of considerations.[74]

4.81. In assessing the options against the Authority's statutory duties, we have considered the impact of the proposals on:

- Networks, social considerations and the environment
- Consumer costs

[73] 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").
[74] 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

- Security of supply considerations

Networks, social considerations and the environment

4.82. One such consideration is the financeability and long-term stability of the regulated networks that provide benefits to their users. Incentives to use smaller EG to reduce transmission system charges that are not based on system benefits could lead to inefficient investment and increased charges for remaining users. This then leads to a greater incentive to avoid charges. Options that reduce distortive incentives to avoid or reduce transmission charges by paying smaller EG are therefore likely to better facilitate these aims.

4.83. The Authority must also have regard for the impact of any changes on vulnerable consumers of any kind.[75] 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.

4.84. 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 some network investment, whereas inefficiently sited and dispatched smaller EG could lead to increased costs and inefficient investment in transmission and distribution network capacity. 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.

4.85. 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 that 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 for emissions than those without grandfathering, as less efficient plant are likely to be dispatched when not in merit. These plant could continue dispatching out of merit for the duration of their grandfathered payment period (10-15 years). It was suggested in one consultation response that there is a correlation between periods of high demand and high carbon emissions, and that the proposals should be amended to target only non-renewable operators, with the respondent suggesting that renewable demand reduction leads to lower emissions. This is not an option available to us, and we note that much embedded generation is facilitated by non-renewable thermal generation, meaning that retaining the TDR benefit may lead

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

to higher emissions. The quantitative analysis set out in the chapter 6 suggests reduced TDR payments will lead to a fall in carbon emissions.

4.86. 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 7 - 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

4.87. We believe that the current payments to smaller EG is likely to lead to out-of-merit dispatch, distorting the market and driving down 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 runs at peak.[76] A more efficient market is likely to lead to lower overall costs for consumers.[77] Therefore, our 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, for example, if payments to generators are more cost-reflective[78] and our view is that more cost reflective payments to EG are likely to lead to lower costs overall. Our view is that immediate change is likely to lead to the greatest reduction in consumer costs overall.

4.88. We expect that ancillary service[79] costs are likely to rise in the short-term under options that reduce payments to smaller EG, as some 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. This is a concern raised by some transmission-connected

[76] 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.
[77] Consumer costs, as set out in the Frontier/LCP supplementary modelling report supplementary modelling report that accompanied our minded to decision and draft impact assessment, include the cost savings from not paying the TDR to embedded generators, CM payments, Wholesale and CfD costs, and the cost of unserved energy . System costs cover fuel, variable opex, carbon prices, plant capex, and unserved energy. More information can be found in the supplementary modelling report. There may be additional effects on network costs, as additional transmission or distribution network investment may be triggered by plant coming on to the system. However, new plant may use existing or recently decommissioned connections, and may not require significant network investment. The location of new plant could also significantly impact the amount of new investment needed. Due to this unpredictability, the modelling would be very sensitive to input assumptions, and so network costs are not modelled.
[78] Other subsidy-driven distortions will remain.
[79] System services such as frequency response, voltage support and black start.

generators who responded to our consultation, noting that the current arrangements may be contributing to an inability for some plant to gain ancillary service contracts due to the current un-level playing field.

4.89. 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 may be needed to cover costs that might have been previously met by TDR payments. In theory, a removal of a distortion will see the providers submitting more cost reflective bids, which may mean higher bids from some generators, and a different group of providers when compared against the status quo. Whilst the CM price may increase[80], 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 TDR payments across all providers are likely to lead to better consumer outcomes.[81]

4.90. The impact of changes on investors is highly dependent on the nature of those investors. We think that the potential for changes to the TDR payments is likely to have been considered as an input to many smaller EGs' business plans, as these arrangements have been a subject of industry debate for a number of years. The realisation of a well-known risk would not be expected to fundamentally alter investors' perceptions of future risk.

4.91. It has also been argued that the cost of capital for embedded generators might increase unless grandfathering is not introduced. If there was a standard policy of grandfathering for changes to network charging arrangements, then we could accept that any decision not to accept grandfathering proposals would need to set out why we were proposing to deviate from such a standard practice. However, there is not a standard practise of grandfathering of such changes, and hence there should not be any current expectation of grandfathering. We do not consider the adoption of options without grandfathering to be likely to lead to an increase in hurdle rates across the industry.

4.92. Phased implementation 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. Overall, we think that our decision to accept a

[80]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.

[81] This of course needs to be weighed against investment impacts, among other things.

proposal to phase in the new arrangements should limit the impact on investors' perceptions of regulatory risk.

4.93. 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 8 - 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

4.94. 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. We do not expect there to be a material impact on security of supply risk from CM non-delivery of these providers, even in the options with the most substantial changes.

4.95. 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, however it is unlikely that security of supply will be significantly affected, provided market access for the affected generators is sufficient[82]. We recognise that an absence of grandfathering could cause some operators to review their investment decisions in the short term. It is our view is that a short period of phasing to a cost-reflective payment level is likely to reduce the risk of an impact on investment in capacity with contracts in the CM. The presence of the T-1 auctions also ensures that any capacity with CM contracts that does drop out can be replaced in an orderly fashion. For this reason, we believe there is no reason to believe that security of supply will be materially affected. There may, however, be impacts on CM prices, and we assess this in our quantitative analysis into the impact of grandfathering and phasing options is provided in section 6.

4.96. Some respondents to our consultation suggest that, as EG are treated under the SQSS as negative demand, they have different investment requirements than transmission connected generators. As discussed earlier, any difference in build requirements from smaller embedded generators through the SQSS and transport model is a consequence of the treatment of these generators as negative demand (in

[82] 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

these models) rather than different build requirements. In addition, the TDR is largely a cost-recovery element and so does not have a direct link to the investment requirements of the system. It has also been suggested that EG is inherently more secure than transmission-connected generation as it is made up of multiple smaller units. If this is the case, it could be due to multiple small generators having lower risk of supply loss than smaller numbers of large generators[83], something which would be the case regardless of the voltage level of connection. This is quite different to an advantage from having a distribution connection rather than a transmission connection.

4.97. 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 exclude grandfathering, may lead to some operators leaving the market. Where investors experience a loss, but assets remain operational and are taken on by other operators, security of supply is unlikely to be harmed, but where the assets are mobile there may be a need to replace this capacity, bringing additional CM costs. Nonetheless, even in a worst case scenario, we do not expect market exit by smaller EG to have a significant impact on security of supply.

4.98. Although options that could lead to significant changes in dispatch behaviour may make forecasting of system demand more difficult in the short-run, as we set out above, we do not anticipate that changes to TDR payments are likely to materially impact security of supply.

4.99. Table 9 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 10 sets out our assessment of implementation options against our statutory duties in relation to security of supply.

[83] The reverse may be the case if all the multiple small units have common output drivers, e.g. high concentrations of small embedded wind, solar, or triad sensitive reciprocating engines may have smaller individual units but they are likely to have coincident running on high demand, sunny or windy days, and coincident low load factors on other days. It is likely the investment costs would be the same as for larger units.

Table 9 - 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	Neutral
Smaller reductions in payment	Neutral

Table 10 - Assessment of Security of Supply considerations – Implementation

Security of Supply considerations	
Implementation	**Impact on statutory duties**
Phasing	Neutral
Immediate	Neutral

Shortlisting of options

4.100. 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.

Value of x

4.101. Having assessed all options available for the value of 'x' and considered which are likely to better facilitate the code objectives than the status quo, our view is that most of the options submitted to us better facilitate the CUSC objectives. We have carefully reviewed our own analysis and that submitted to us in response to our consultation to shortlist the values of x for more detailed assessment. The evidence submitted to us indicates that smaller EG locating on the distribution network can avoid the need for additional reinforcements at the GSP. Although there may be scope for improvements to the methodology put forward to us, we believe that payments which reflect this saving are more likely to best facilitate the CUSC objectives.

4.102. Values linked to the TGR are also more likely to best facilitate competition between smaller EG and other generation, compared to the status quo. To the extent to which it may improve competition between generator types is discussed further in chapter 7.

4.103. Values linked to the lowest locational element may lead to unintended consequences, such as the reintroduction of large TDR-style payments to smaller EG, should locational signals increase in future.

4.104. As we note above, there is no cost reflective link between the level of the locational charge in the zone where the signal is most strongly negative and the system-wide benefit. Further, a link between the lowest locational signal and the value of 'x' means that changes in the strength of locational signals will alter the overall payment to smaller EG, with no cost-reflective driver. As such, we assess that these options are less likely to best facilitate the CUSC objectives.

4.105. Those options linked to fixed figures, such as £20.12, £45.33 or £34.11 we also assess as less likely to best facilitate the CUSC objectives. The options presented to us did not present compelling evidence that these figures were linked to savings smaller EG could bring on the network. Further the fixed nature of the payments mean that even if deemed cost reflective today, there is no automatic means of updating the figures. As a result, we find that these figures are less likely to best facilitate the CUSC objectives.

4.106. Those options linked to the TDR excluding offshore costs are unlikely to significantly address the distortions associated with the current TDR payments since the payments will remain high and a link is retained between the TDR (albeit with the offshore costs removed) and the value of embedded generation. As a result, we find this value of x is less likely to best facilitate the CUSC objectives. This is summarised in table 16 below:

Table 11 - Assessment of values of x against code objectives and statutory duties

Payment level for smaller EG	
Level	**Impact on CUSC objectives and statutory duties**
Avoided GSP	More likely to best facilitate
Generation Residual	More likely to best facilitate
Lowest locational	less likely to best facilitate
Fixed values	less likely to best facilitate
Excluding offshore costs	less likely to best facilitate
Status quo	less likely to best facilitate

Immediate or Phased Implementation

4.107. As we set out in our minded-to decision, we have assessed the options available to us, and consider the consumer cost and competition advantages of a prompt reduction in the level of distortion is likely to lead to the best outcomes for customers. Of the options available, we think there are significant advantages of, and strong stakeholder support for, a phased transition and that these are likely to best facilitate the code objectives. Some respondents provided evidence that an immediate implementation would be in the best interests of consumers, given it removes a distortion in a timely manner. Although we think immediate implementation better facilitates the CUSC objectives than the status quo, options which provide a phased implementation balance consumer benefits with a phased change in arrangements for generators and investors, providing firms with more time to adjust to large changes in charges. Such options are more likely to be consistent with our statutory duties, and hence meet the test in the round.

Table 12 - Assessment of values of implementation options against code objectives and statutory duties

Implementation options	
Implementation	**Impact on statutory duties**
Phasing	More likely to be best facilitate
Immediate	Likely to be best facilitate

Grandfathered options

4.108. We do not believe options which include grandfathering are likely to best facilitate the CUSC objectives, though we recognise that, in many circumstances, they better facilitate the CUSC objectives than the status quo (due to the lower value of 'x' in those options). 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.

4.109. Many options which include grandfathering do lead to better outcomes against the CUSC Objectives (compared to the status quo), but leave in place non cost reflective payments and guarantee the non-cost reflective level for extended periods for a subset of generators.

4.110. 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 dispatch of less efficient plant. 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.

4.111. From our analysis and our consideration of the consultation responses that we have received, we do not consider any parties to have demonstrated a legitimate expectation that these payments would continue and that grandfathering is justified as a result, nor have they demonstrated that continuation of the TDR payments to some or all parties would better facilitate the code objective or better fulfil our statutory duties.

4.112. A number of respondents to our consultation have advocated the adoption of options that afford protections to particular sectors from the modifications. Responses that we have considered included suggestion for protections for so-called “heat-led” or incidental power generation such as CHP or waste-to-energy, renewable generators and particularly those FiT or RO-recipient stations that cannot participate in the CM, very small installations, and those with restricted market access. However, in the context of this Decision, we are restricted to accepting or rejecting the options set out in the Final Modification Report, and cannot design alternative options that have not been through the workgroup process. The grandfathering options available to us are restricted to CM14/15 and CfD holders (or existing generators) and do not include phased implementation for other plant. We would also note that the network charging regime is not the place for supporting particular technologies or market sectors, but to ensure the costs of the monopoly networks are recovered in a way that is non-discriminatory, non-distortive, and sufficiently reflects the costs or benefits of the user concerned. We have set out further discussion on the likely distributional impacts of the proposed changes later in this impact assessment.

4.113. The table below sets out our assessment of grandfathering options in terms of which options are likely to best facilitate the CUSC objectives and our statutory duties, compared to the status quo.

Table 13 - 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, WACM19	Less likely to best facilitate
Commissioned before a given date – further out	WACMs 20-22	Worse than status quo

Conclusions

4.114. To summarise the above, our view is that the proposals that are most likely to best facilitate the CUSC objectives are those that:

- Include avoided GSP costs in the value of ‘x’; and
- Do not provide for grandfathering of current TDR payments for any category of smaller EG.

4.115. Our view is also that options that provide for phased implementation are more likely to be in line with our statutory duties. However, we recognise that phased implementation comes at a greater cost to consumers relative to immediate implementation and, thus, recognise that the timing and phasing of implementation requires us to weigh the benefits and detriments to investors and consumers. For that reason, we include both immediate and phased implementation options in the shortlisted modifications that we go on to consider in further detail in Section 7.

4.116. In light of the above, our shortlisted options for further analysis are WACMs 3, 4 and 5.

Table 19 CUSC Objectives and Ofgem's Statutory Duties

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

4.117. In Section 7, we also assess the option of accepting WACM4 with a one year delay due to a number of respondents who indicated they would support a substantial delay to the implementation of any new arrangements. We considered it important to consider if any further delay to the implementation of our minded-to decision to accept WACM4 could be in the interests of consumers.

5. Distributional Issues

Chapter Summary

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

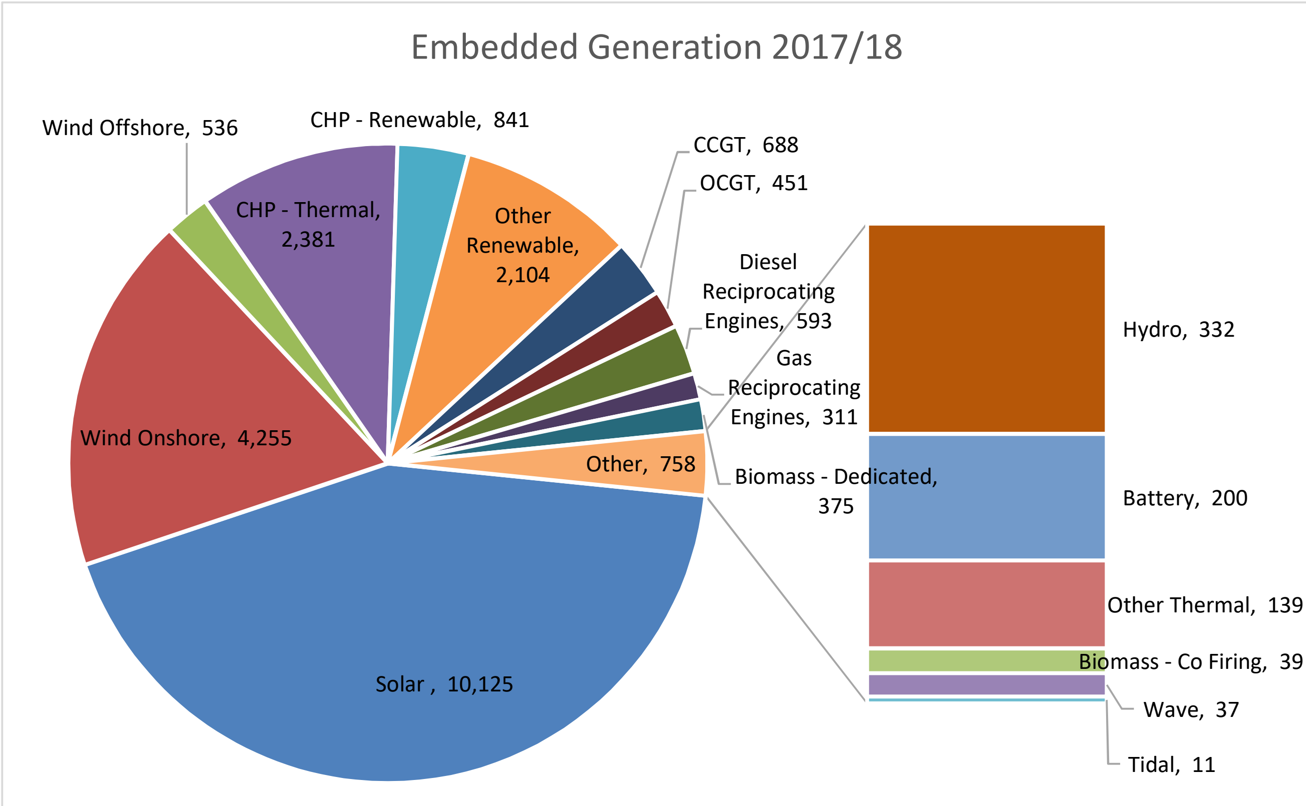
Impacts on Specific Sectors

Discussion and assessment of wider impacts

5.1. This section assesses, both qualitatively and quantitatively, the potential impacts that a reduction in payment to smaller EG would have to specific sectors. Section 6 of this impact assessment covers the quantitative impact of the proposed changes through detailed modelling.

5.2. The chart below shows the makeup of EG on the GB system, as assessed by National Grid in their Future Energy Scenarios 2016 publication. Roughly two thirds of capacity is solar or wind. Solar is highly unlikely to be impacted by the proposed changes as it does not run at triad. Wind generators, whilst they may run at triad by chance, they cannot control when they generate, and as such are likely to see much lower impacts from changes to the TNUoS demand residual that those technologies which focus on running to capture triad payments, including small gas and diesel reciprocating plants. The following section outlines each broad generator type in turn, outlining the potential impacts of a reduction in the TDR payments.

Figure 2 - Embedded generation installed capacity - FES 2016



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. Controllable thermal generation are likely to see the greatest impact on their revenues as a result of a change. We recognise that in some cases, this could require change to business models or the perceived stranding of assets, to recover these lost revenue streams. We understand that for some thermal generators, especially peaking gas and diesel plant, TDR payments can form up to half of their anticipated revenues and operations are heavily geared toward hitting triad periods, which consultation respondents suggest makes a significant contribution to security of supply. We have modelled the impact on security of supply as a result of the changes in the next chapter and do not think the change has a material effect on security of supply.

5.4. 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. As such we do not expect the overall 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, though some respondents to our consultation suggested that their plants would not have been built without these revenue streams.

5.5. 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.[84,85] TDR payments to smaller EG CHP and EfW plant may help to support overall fixed costs for these generators. A reduction in the level of payment to smaller EG would mean that larger EG and transmission-connected CHP and EfW plants will be at less of a disadvantage. Respondents to our consultation noted that smaller EG operating as baseload generators, such as CHP, may be hit disproportionately, as they are unable to profile their operations as flexible peaking plant may be able to, though we would also note that these plant would likely currently be receiving significant BSUoS embedded benefits. We recognise that the levels of these are not known in advance but that they can still constitute a significant revenue stream. We set out further analysis on BSUoS links later in this chapter.

5.6. Public authorities who own onsite generation CHP and EfW plants are also likely to be impacted as a result of a reduction in TDR payment level. 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, which will benefit all energy consumers.

5.7. We received a number of responses to our consultation that pointed out concerns over the impact of our proposed changes to the EfW and water utility companies. For example, a number of respondents noted that the changes could lead to higher waste disposal costs through higher gate fees for EfW plants or higher waste water processing costs which could feed through to higher water rates for users. Respondents notes that these plants have to be close to the communities they serve, so have a limited ability to respond to locational signals. Despite this, it is not right that these users receive non-cost-reflective revenues redistributed from other users, through the TDR payments. Similar arguments may be made for certain industrial users, restricted by their business models. We recognise that this may lead to higher costs for some, but note that the current lower costs are due to a non-cost reflective distortion. In addition to this, it was highlighted by some respondents that some of these CHP and EfW generators are likely recipients of Renewable Obligation support.

[84] 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.
[85] DECC figures, 2015.

DSR and Storage

5.8. We recognise that a reduction in payments to smaller EG may increase the incentive to move generation behind the meter (BTM) to net off consumption and reduce charges. We are proposing to consider the collection of residuals as a priority area for the TCR. Some respondents to our consultation have suggested that changes to the payment of the TDR to EG, but not to BTM and DSR, constitutes an end to the equivalence of demand-side response and generation. This is not necessarily the case, as the cost-reflective elements will retain equivalence. The residual, cost-recovery elements will be considered as part of the TCR.

5.9. Some electricity storage projects at distribution level may rely on the TDR payments to some extent. Storage projects are likely to be aiming to capture peak prices brought about by short term wholesale volatility. In theory, those options with an immediate implementation may have a greater impact in the short term, while options with grandfathering may mean that the volatility and peak prices that storage operators aim to capture might be dampened. The removal of non-cost reflective TDR payments may allow storage at all voltage levels to better compete and capture revenues. Grandfathering would also see some existing operators offered a competitive advantage over newer, potentially more efficient or innovative operators.

Renewables

5.10. We expect the impact of reduced TDR payments on intermittent renewables to be less than that of dispatchable[86] generation. For example, solar generation[87] is highly unlikely to receive TDR revenue under current arrangements, as solar plant is generally not generating in the winter early-evening periods that triad usually falls on. We therefore expect the impact on solar to be minimal. Wind is intermittent and non-dispatchable, with overall winter load factors around 30%. Wind generation output is generally lower than this during triad. Due to the fact that wind cannot control when it generates, wind generators will not be able to control whether they hit triad. 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, albeit at a significantly lower level.[88]

5.11. Anaerobic Digestion (AD) plants and landfill gas plants that prioritise electricity generation over gas production may be particularly impacted, especially if they aim to generate over the triad period. Options that reduce payments to smaller EG may reduce revenues and in some cases may prompt a switch from electricity

[86] Dispatchable generation is able to be turned off or on at will, and is contrasted with intermittent generation, which is not controllable.
[87] Future Energy Scenarios 2016 states there is around 11GW distribution connected solar.
[88] Future Energy Scenarios 2016 states there is upwards of 5GW distribution connected wind.

export to the distribution networks to private wire electricity export, or to biogas production if this is more cost-effective.

5.12. Some respondents have suggested that FiT recipients who currently have PPA agreements with suppliers, which include TDR payment, will switch to the FiT guaranteed export tariff, rather than a PPA.[89] They note that PPAs may need to be renegotiated to accommodate these changes. We do not expect the removal of the TDR payment to disproportionately reduce competition in the PPA market or reduce the requirement to contract smaller EG by suppliers. We would expect that competition will still exist to take the power, but it will be cost reflective, rather than on an incentive to avoid charges. We would also point out that for FiT recipients, the choice on whether to receive the guaranteed export tariff or to have a PPA is an annual choice, so should not have a significant impact on suppliers.

5.13. We note that there are not currently well developed markets for flexibility at all levels of the networks. A number of consultation respondents also noted that RO, CfD and FiT recipients are not eligible for CM contracts so cannot expect to replace this revenue through that channel. A number of respondents have suggested that renewables, variously intermittent or dispatchable, should be excluded from the changes.

Innovation

5.14. Our final view is that the network charging regime is not the correct mechanism 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.

Estimated financial impact according to sector

5.15. In this section we set out the estimated impact a move to WACM4 will have on each of the different sectors if the TDR payment is replaced with a value of £1.62/kW. The impact of the change will have a varying impact on different technologies/industry sectors, as explained qualitatively above. This mostly revolves around their operating pattern and whether they can predictably hit the three triad half hours. As such, controllable generation who hit the three triad half hours predictably are most likely to be effected. Intermittent generation who do not hit

[89] Power Purchase Agreement

triad are unlikely to have factored the TDR payments into their business plans. Solar is very unlikely to generate at triad and is therefore unaffected by this change.

5.16. Using Future Energy Scenarios (FES) 2016 data, broken down by the installed capacity per sector and output at winter peak, we calculated the impact on the different technology sectors.[90] It should be noted, that this is in relation to the output of those smaller EG connected to the distribution network and is based on estimates in the FES.

Table 14 - Impacts by technology types

Technology Impact	
Technology	**Impact**
Thermal CHP (Gas), Waste and Waste CHP, Biomass and Biomass CHP, OCGT, CCGT, Gas and Diesel Reciprocating engines,	High
Anaerobic digestion and CHP, Sewage gas and CHP, Landfill gas and Hydro	Medium
Tidal, Wave, Wind (onshore and offshore)	Low
Solar	n/a

5.17. A high impact is a £/kW impact across the sector of more than £50/kW, medium is £30-50/kW, low is sub £20/kW. The impact is calculated by looking at the projected revenues each technology would be expected to receive, if they generated at peak, in 2020/21 under a status quo scenario (with TDR payments rising to c.£69/kW), compared to what they will receive if WACM4 is implemented (using £1.62/kW). This change in revenue is then divided by the total installed capacity on the system. It should be noted that this change is only taking into account the forecast change in TDR payments and does not account for additional revenues being made up in other markets.

[90] It should be noted that the FES data is forecast data, and as such, is only a best estimate of future technology rollout. A Slow Progression scenario was used to be consistent with our modelling approach.

5.18. The table below shoes the installed capacity, sector contribution at peak, the sector impact and the average revenue impact for each sector, in 2020/21 according to the FES 2016 scenarios, under a WACM4 scenario.

Table 15 – Estimated monetised impacts per sector, based FES 2016 capacity and load factor projections

Category	Sector Installed Capacity (MW)	Sector Peak Contribution (MW)	Sector impact 2020/21 (£m)	Average revenue fall 2020/21 (£/kW)
CCGT	688.10	619.30	39.01	56.69
Diesel Reciprocating	1,500.00	1,418.10	89.32	59.55
Fuel Cell	0.00	0.01	0.00	0.00
Gas Reciprocating	867.70	820.40	51.67	59.55
OCGT	506.80	479.10	30.18	59.54
Renewable CHP	1,060.00	848.50	53.44	50.42
Renewable non-intermittent	2,584.20	1,901.13	119.74	46.34
Solar	14,876.20	0.00	0.00	0.00
Storage	220.00	191.12	12.04	54.72
Thermal	1,416.80	1,263.20	79.56	56.16
Thermal CHP	2,068.00	1,861.15	117.22	56.68
Wave/tidal	473.50	337.04	21.23	44.83
Wind	5,460.60	1,070.16	67.40	12.34
Grand Total	***31,722***	***10,809***	***681***	***21***

Renewable non-intermittent includes Anaerobic Digestion, Landfill Gas, Sewage, Waste, Biomass Co Firing, Biomass - Dedicated and Geothermal

Impact of potential change according to different business models

5.19. In this section we provide illustrative examples of the impact of the changes on the level of embedded benefit received by smaller EG, focusing on five business models. The example includes non-locational TNUoS and BSUoS embedded benefits only, and include both the payment of TNUoS/BSUoS, and the avoided payments of both. The full workings and methodology are available in appendix 5. This example does not indicate that we have reached a conclusion about whether the other embedded benefits should be changed. These are proposed to be considered as part of the TCR.

5.20. The five business models are set out below. The examples cover conventional generation, of varying business models, and intermittent wind generation.

5.21. In these examples, it is assumed that all the benefit is passed onto the generator. We recognise that this is unlikely to be correct in all cases. In other cases, the embedded benefit arrangements will still be causing a redistribution of charges from one group of users to another, but may not bring the overall increase in transmission charges that occurs when embedded generators are paid. This example uses an average BSUoS level of £2.54/MWh, an estimate of the 2016/17 average. 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. We do recognise, however, that generators will not know the BSUoS levels in advance as BSUoS levels are determined ex-ante. These are illustrative examples only, and don't necessarily reflect the actual benefits realised by any particular smaller EG, and neither do they account for the locational embedded benefit caused by non-comparability of generation and demand zones or for BSUoS benefit not being paid in certain GSPs..

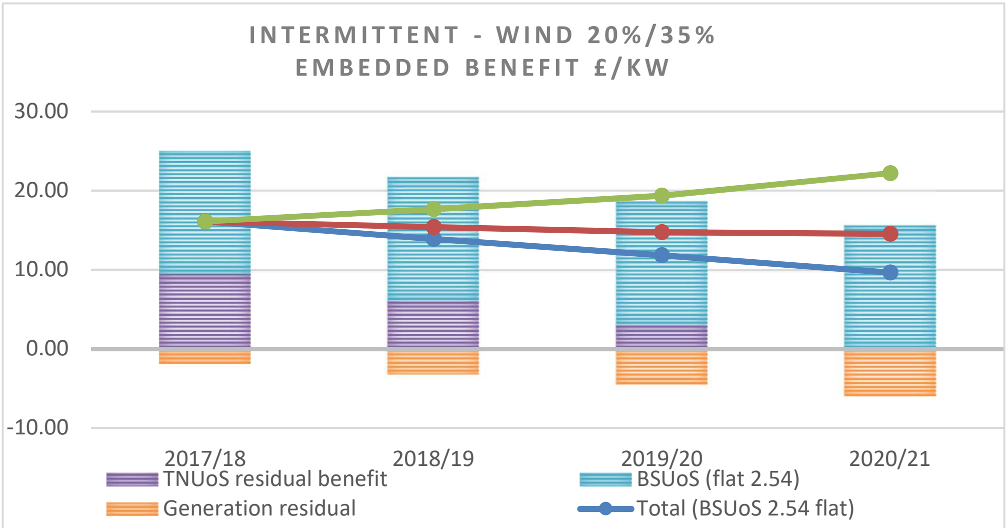
Table 16 - Modelled scenario

Scenario	Type of generator	Output at peak	Annual Load Factor
Intermittent 20/35	Wind	20%	35%
Intermittent 05/35	Wind	5%	35%
Non Intermittent 90/05	Peaker	90%	5%
Non Intermittent 80/50	Conventional	80%	50%
Non Intermittent 90/80	Baseload	90%	80%

Intermittent - Wind 20% Peak output /35% Annual Load Factor

5.22. Below we set out the possible level of non-locational benefits now and after the proposed changes set out in WACM4 for intermittent generation. Our example assumes 35% load factor for BSUoS. Our analysis suggests that substantial non-locational embedded benefit is likely to remain for wind generation, driven entirely by BSUoS. With 20% peak load factors, TDR revenue is lost due to the proposed phase out of TDR embedded benefit. Once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £9.63/kW and £22.20/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

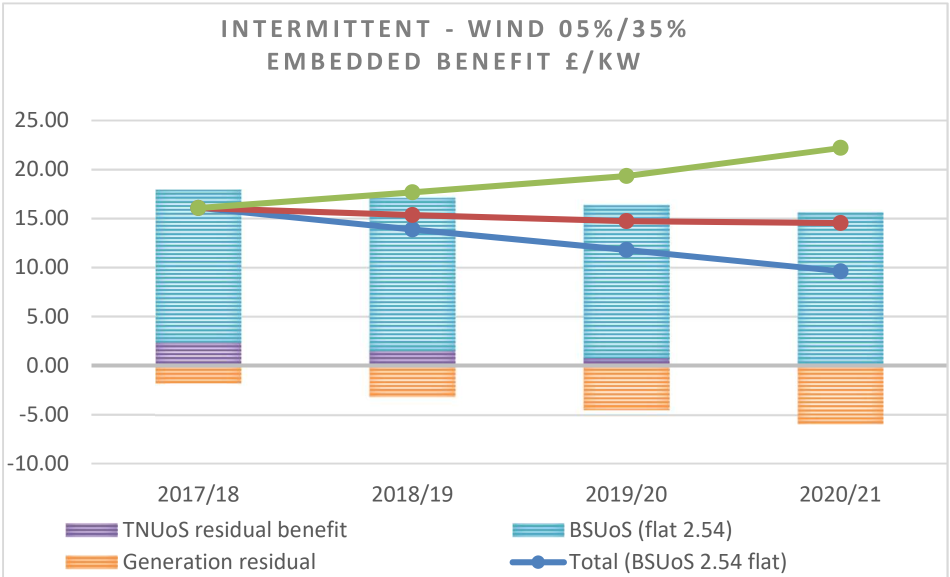
Figure 3 - Intermittent 20/35



Intermittent - Wind 5% Peak output /35% Annual Load Factor

5.23. This example assumes 35% load factor wind, with output at triad being 5% (due to the likelihood that triad periods coincide with low embedded wind output, pushing up peak transmission system demand) and suggests that substantial non-locational embedded benefit is likely to remain for wind generation, driven entirely by BSUoS. Due to low peak load factors and the proposed phase out of TDR embedded benefit, the TDR benefit is entirely removed for these generators. While under WACM4 EG will not receive the negative TGR payment, once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £9.63/kW and £22.20/kW benefit in 2020/21 depending on the assumed level of BSUoS charges. This is set out in the chart below.

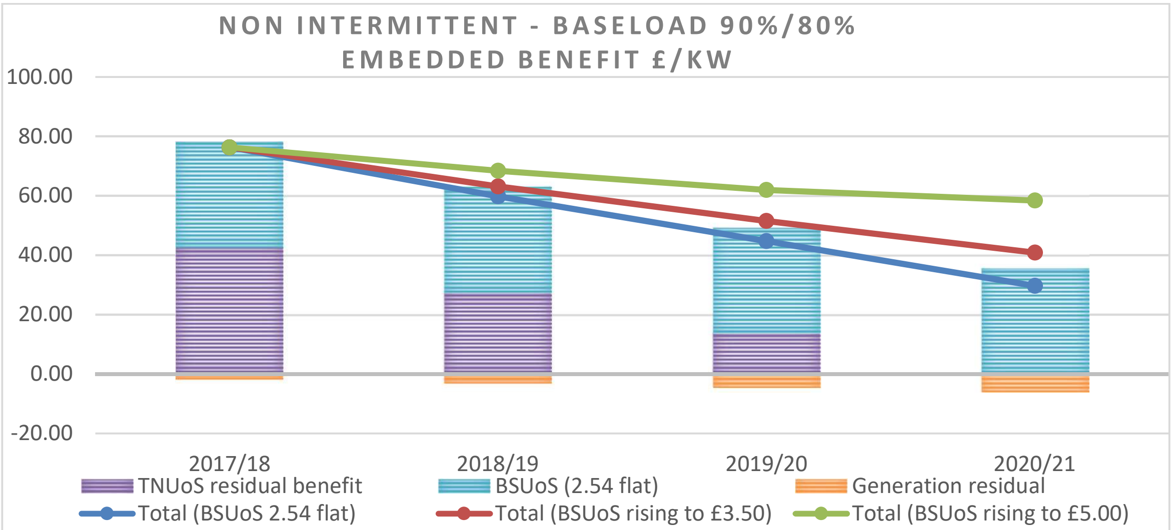
Figure 4 - Intermittent 05/35



Non-Intermittent - Baseload 90% Peak output /80% Annual Load Factor

5.24. This example assumes 80% load factor for BSUoS, reasonable for a CHP generator running baseload, such as a plant with a large heat load. Our analysis suggests that very large non-locational embedded benefit is available for these operators, as high load factors bring high BSUoS benefits. Once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £29.65/kW and £58.38/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

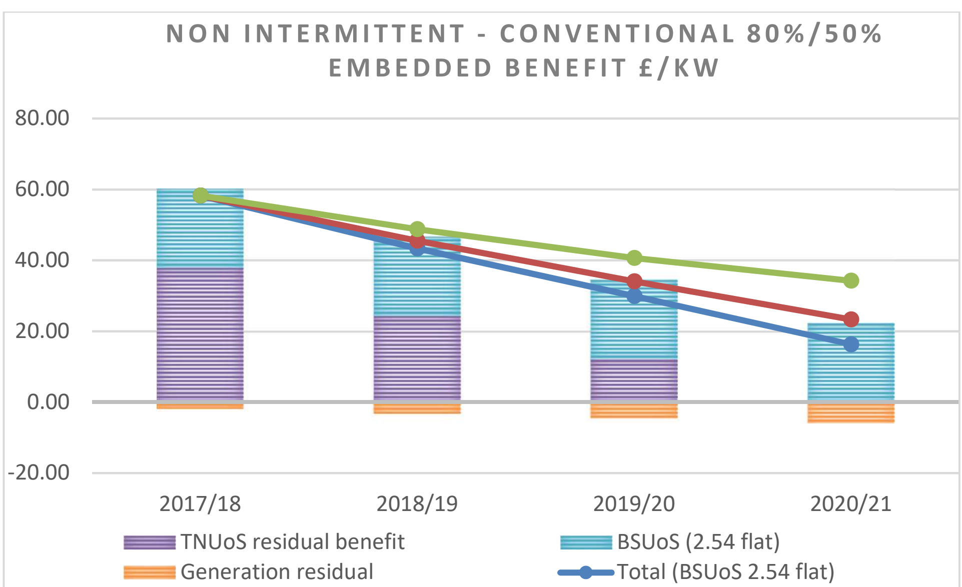
Figure 5 - Non Intermittent 90/80



Intermittent - Conventional 80% Peak output /50% Annual Load Factor

5.25. This example assumes 50% load factor for BSUoS, which is reasonable for a small embedded non-CHP CCGT generator running some baseload operations. Our analysis suggests that substantial non-locational embedded benefit is available for these operators, as higher load factors bring substantial BSUoS benefits. Due to the proposed phase out of TDR embedded benefit, the TDR benefit is entirely removed for these generators. However, once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £16.30/kW and £34.26/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

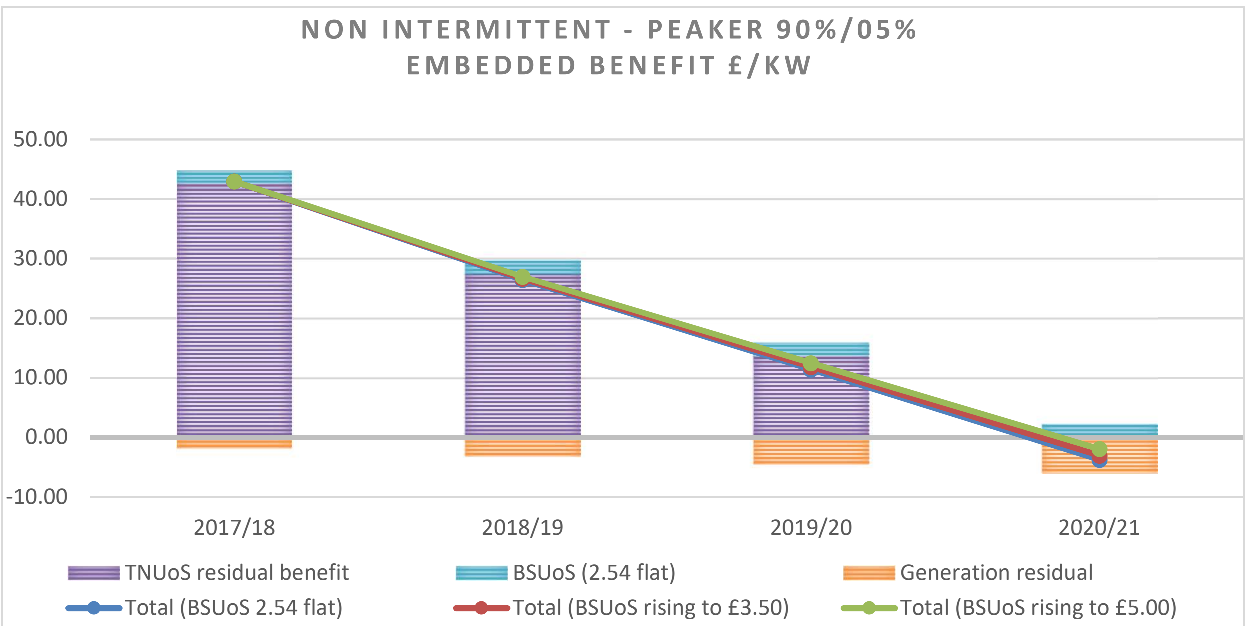
Figure 6 - Non Intermittent 80/50



Non-intermittent – Peaker 90% Peak output / 5% Annual Load Factor

5.26. This example assumes 5% load factor for BSUoS. Our analysis suggests that substantial non-locational embedded benefit is largely removed for peaking generation, as low load factors limit BSUoS benefits. Due to the proposed phase out of TDR embedded benefit, the TDR benefit is entirely removed for these generators, and they face competition from transmission connected generators that will receive the negative TGR payment on their whole Transmission Entry Capacity (TEC). Once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £-3.72/kW and £1.93/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

Figure 7 - Non Intermittent 90/05



Summary of impacts according to different business models

5.27. While the level of non-locational embedded benefits received by a generator is influenced by location and technology, it is also highly dependent on load factor. By 2020/21, generators with load factors higher than the low teens are still likely to be at a competitive advantage in relation to cost recovery charges than a comparable transmission connected generator.

Impact of changes on TNUoS demand charges

5.28. We have seen analysis produced during the workgroup process and produced by National Grid, that suggests that an increase in the charging base, from 49.1GW to 56.6GW, could lead to a reduction in the size of the TDR from the then forecast of c.£47.50/GW to c.£42.50/kW in 2017/18, by spreading the required revenue over a greater number of users. This is a fall of 10.5% and assumes an addition of 7.5GW to the demand charging bases which is running at peak times. This means that we would expect demand users to see a reduced TNUoS bill, in addition to the reduced payments by suppliers to smaller EG (which is recovered from demand), which we would expect to further reduce consumer costs.

6. Quantitative modelling results

Chapter Summary

This chapter sets out the approach and results for our quantitative analysis and presents the impacts of the different options presented to us for decision. It also includes additional sensitivities on areas of interest raised during our stakeholder engagement.

Modelling information and assumptions

6.1. We have commissioned LCP / Frontier to undertake analytical modelling which allows us to assess the market impacts of all the 25 proposals that have been submitted 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, with a particular focus on WACM4. The consumer and system cost savings for the other modelling results are in Appendix 4, which 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 figures 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 principles based and predictable, 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. We have not relied on modelling outputs as the sole or predominant basis for our 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. When choosing assumptions, we assumed that charges would remain flat, rather than continue to increase, so they could be considered conservative in nature. They therefore may understate the potential benefits of changes. This was noted by a small number of respondents to our consultation. 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 modelling outputs. As such, we use these results as an indication of the relative merits of the proposals, in conjunction with a principle-based assessment.

6.4. The modelling we have undertaken on the expected consumer costs and benefits of change to the embedded benefits regime utilises the EnVision model developed by Lane Clark and Peacock LLP (LCP). This is a fully integrated model of the GB power market which models the build out and closure of generation and the various market interactions, using the forecasts set out in National Grid's 2016 Future Energy Scenarios (FES 2016). The use of the model and the FES 2016 data was largely supported in the consultation responses we received, though one stakeholder suggested that the model could be improved by taking into account possible future changes to the daily usage and generation profiles rather than using historical figures. We are comfortable that the model is sufficiently rigorous to support what is a primarily principles-based decision.

6.5. The model does not look at network build on the transmission or distribution system, or connections costs, nor does it assign a location to generators, assuming this to be neutral when taken in aggregate. We are confident that this is a reasonable approach as the need for reinforcement will be locational specific and in some cases new connections will utilise existing connections whether on the transmission or distribution system. Additional connections to the networks are therefore assumed to be neutral. We do not have evidence to suggest that the current charging system has a marked influence on the location of embedded generation.

6.6. Following the publication of our minded to position, modelling report and data in March, we held a workshop with Frontier Economics and LCP. Using feedback from this session and our consideration of our consultation responses, we updated some aspects of our modelling. A number of updates have also been made to account for updated tariff forecasts released by National Grid since the publication of the minded to decision. Updates were made to the modelled plant mix using the most recent CM auction data. A number of sensitivities have also been carried out to assess how sensitive the model's results are to changes in the assumptions.

Modelling results

6.7. 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.

6.8. 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. The values of 'x' that we used in our original modelling for Scenarios 1-3 are unchanged, while the final level of the TDR used in the status quo scenarios and the level of the generation residual in all scenarios has been updated in line with the latest TNUoS forecasts published by National Grid.

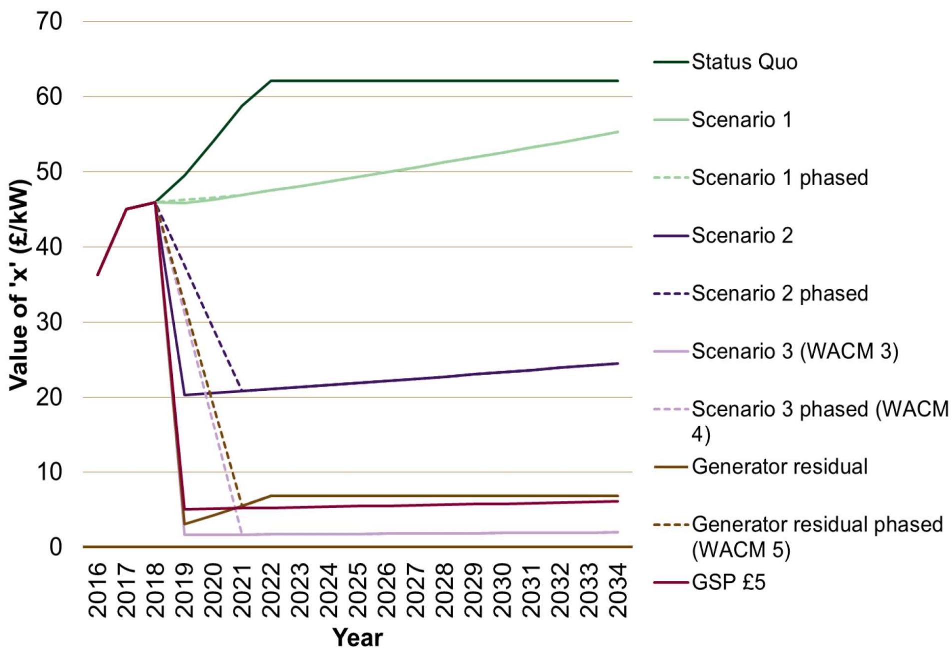
6.9. Over the current five year forecast for transmission charges, the lowest locational charge will average £20.34/kW. Our analysis indicated that this was sufficiently close to the modelled Cornwall Energy estimate of £20.12/kW to act as a reasonable proxy. As such scenario 2 is used to estimate various permutation of WACMs 6, 7, 9, 15, 16 & 23.

Table 17 - Explanation as to how each scenario was modelled

Scenario	Value of 'x'	Value of 'x' Sensitivity?	Explanation
Scenario 1	£45.33/kW + RPI	No	This is equal to the current TDR level being frozen
Scenario 2	£20.12/kW + RPI	No	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	Yes - £5/kW	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 2022 then flat thereafter	No	Equal to the TNUoS generator residual, with the inverse sign, forecast out to 2022 and then flat thereafter.
Status quo	Modelled according to National Grid's forecasts, rising to £69.59/kW in 2022, then flat thereafter	No	The TDR increases in line with National Grid's forecast until 2022 and then remains flat thereafter.

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

Figure 8 - Value of X in each scenario



6.11. For each relevant option, we have modelled the additional impact of phasing and grandfathering[91]. 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.

6.12. For each option, we also modelled the impact of adding grandfathering in three 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.

6.13. The status quo options and options which include grandfathered, do not assume any drop-out over time of grandfathered plant, as this would lead to penalties under the CM regime and because those grandfathered plant would be

[91] This looked at the payment flows only. We did not, for example, look at the dynamic incentive effects of grandfathering (ie stopping the closure of inefficient plant)

receiving significant revenues (£45.33/kW). Drop-out of plant before delivery was also considered and will be discussed later in the next section.

Feedback from stakeholders on our modelling

6.14. Through our engagement with stakeholders, our modelling workshop, other meetings and our consultation, we received a number of comments on our modelling.

6.15. Some stakeholders suggested that the 7.5% real hurdle rate used in our model was too low. We do not think this is likely to be material with regards to the impact on our modelling outputs. We have separately received representations that suggested higher hurdle rates could be required for certain investments as a result of our decision or by harmed investor confidence, though other respondents suggested that the implementation of our minded to decision would be the realisation of a well-known regulatory risk. We have seen no evidence which leads us to believe that this decision will cause an increase in hurdle rates for the industry more generally, and believe the phased implementation we have proposed should allow firms time to adjust their business models to any change in TDR revenues. We did not believe further modelling work was necessary in this area.

6.16. A number of stakeholders noted that the consumer cost impact of CM 2014 and CM 2015 contract holders choosing to renege on their agreements (due to the reduced revenues they would expect without TDR payments) had not been assessed[92]. Respondents stated that a change in TDR payment levels would lead to some, predominantly CM 2015 contract holders from not building and terminating their CM contracts leading to marked security of supply and price impacts. We acknowledge that more information was needed on the potential costs of such a scenario and therefore took the decision to look into this further using additional modelling sensitivities.

6.17. We modelled the impact of both a 25% and 50% drop out between the CM14/15 auctions. This included some drop out of reciprocating engines with 1 year contracts, as well as 'other smaller EG' which is not participating in the CM. These figures were profiled to recognise that a significant proportion of CM14 plant had already built, while sizable proportions of CM15 plant was not yet at financial investment decision stage. The 1 year and non-CM EG figure were arrived at using estimates of reciprocating engine capacity. The detailed drop-out scenarios are set out below. It should be noted that both medium and high drop-out scenarios are considered unlikely, and the results indicate that security of supply is unlikely to be impacted by even significant levels of CM 14/15 plant drop-out. Frontier/LCP estimate that the cost to consumers of being required to procure an additional

[92] Our initial analysis had looked at the security of supply impact of scenarios where all CM2014/15 EG had not delivered, but the price impact was not modelled.

577MW (a very significant amount that is not considered likely) through the CM, in a medium drop out scenario, to be in the region of £258m.

6.18. We considered running additional sensitivities to restrict diesel build but understand that DEFRA discussions with industry on whether to further restrict diesel generation are ongoing. We therefore do not have sufficient grounds to assume at this point that diesel plant will not be built though accept this may change in future.

Table 18 - Drop-out sensitivities

Drop Out	Recips with 15 year contracts			Recips with 1 year contracts	Other smaller EGs (CM and non-CM), excluding CHP and intermittent
	CM2014	CM2015	CM2016	All	All
Approximate capacity, MW	785	965	1,310	650	2,940
Total	1,750				
Baseline (low) drop-out rate	0%		0%	0%	0%
Medium drop-out rate	25% (438MW)		0%	10% (65MW)	2.5% (74MW)
High drop-out rate	50% (875MW)		0%	20% (130MW)	5% (147MW)

6.19. It was noted by a number of stakeholders that the avoided GSP estimate used in the workgroup sessions and our modelling was derived in 2013/14 and was based on data from that time. Since the discussions in the workgroup, National Grid has been conducting a review of its estimate of avoided GSP costs. Its initial analysis indicates that the figure is likely to be in the range of £3/kW to £7/kW. An additional sensitivity has therefore been run where the avoided GSP infrastructure cost is £5. National Grid are in the process of calculating an updated value.

Table 19 - Avoided GSP sensitivities

Avoided GSP	
Baseline £1.62/kW	Increased (estimate) £5.00/kW

6.20. We received extensive feedback that the level of efficiency and capital cost for reciprocating engines was too low. Other technologies were also suggested to be more expensive than set out in the BEIS Low estimates we used.

Table 20 - Capex sensitivities - technology values (£/kW)

Capex	BEIS Low (original modelling)	BEIS Medium
CCGT	416	523
OCGT	339	368
Reciprocating diesel	255	420
Reciprocating gas	345	480

6.21. We carried out some investigations into possible sensitivities around capital costs and thermal efficiencies of generating plant. We decided to run sensitivities using the BEIS medium assumptions for CCGT, OCGT, and diesel and gas reciprocating engines. As capital costs are generally related to efficiencies, increased efficiencies were combined with increased capex cost in further modelling. This approach ensured the model remained internally consistent. The low capex sensitivity was paired with BEIS low efficiency figures, and the BEIS medium capex was combined with the BEIS low efficiency figures for all plant except gas reciprocating plant. In those scenarios with higher (BEIS medium) capex, we increased reciprocating engine efficiencies by +5% and +10%, to reflect stakeholder comments that the BEIS figures underestimated the efficiency of gas reciprocating plant in particular. The low efficiency scenario was also paired with a BEIS Medium capex cost to check the sensitivity of the model to an increase in capex alone. These scenarios are set out below.

Table 21 - Capex/ thermal efficiency sensitivities

Capex levels and efficiency of Gas Recips			
BEIS Low 32%	BEIS Medium +0% (32%)	BEIS Medium +5% (37%)	BEIS Medium +10% (42%)

Modelling results - Updated base case, sensitivities and differences from previous results

6.22. In this section, we set out the modelling updated results for the scenarios and sensitivities.

6.23. The updated modelling produced data consistent with the previous modelling runs. The tables below set out at a high level the scenarios and what the impact of the updated modelling assumptions have our the consumer benefit in our 4 scenarios. It should be noted that this shows the NPV of grandfathering CM/CfD smaller generators only, as seen in our shortlisted options[93].

Table 22 - New modelling results

Scenario (value of x)	Consumer NPV[94] £bn	With Phasing £bn	With Grandfathering £bn
1 (£45.33/kW)	1.6	1.6	1.6
2 (£20.12/kW)	5.4	5.3	4.9
3 (£1.62/kW)	7.7	7.5	6.9
Generation Residual	6.5	6.4	5.8

6.24. The NPVs of each WACM, and its changes against the previous modelling, is set out below. We estimate a year delay, with implementation in April 2019, to cost £500m.

Table 23 - Changes from previous modelling results

Key changes to modelling results	Previous estimate £bn	New Estimate £bn	Differences £bn
WACM3	7.4	7.7	0.3
WACM4	7.2	7.5	0.3
WACM4 + 1 year delay	c.6.9	c.7.0[95]	0.1
WACM5	7.4	6.4	-1.0[96]

6.25. The results suggest that significant consumer benefits remain in the options shortlisted in our IA in the updated modelling. One key change appears have occurred in the Generation Residual modelling runs. We believe the previous Generation Residual run showed better results than Scenario 3 as additional plant

[93] Assuming that the generation capacity awarded contracts in the 2014 and 2015 CM auctions delivers as expected, the grandfathering options can be expected to have no material effect on the plant mix. Therefore the grandfathering options leave the system costs largely unchanged. The impact of plant not delivering is assessed separately through the drop-out sensitivities.
[94] The savings that go into these categories are described in the consumer and system cost sections below.
[95] We estimate that a one-year delay to implementation from April 2018 to April 2019 is likely to cost £520m.
[96] LCP noted that the previous Generation Residual run showed better results than Scenario 3 as an additional CCGT cleared. The difference between runs suggests some sensitivity to plant mix which has not occurred with the updated generation residual forecasts.

cleared in early CM years. This does not appear to have occurred with the updated generation residual forecasts.

Sensitivities

6.26. The below table sets out the modelling results for the sensitivities we have run. The findings suggest that the modelling is not particularly sensitive to the changes made. Differences are based on Scenario 3 phased baseline (equivalent to the avoided GSP WACM4) total of £7.5bn, except the avoided GSP sensitivity, which is based on WACM3, to show the maximum potential impact of moving the avoided GSP figure from £1.62/kW to £5/kW. The inclusion of phasing would simply reduce the difference in consumer savings between the baseline and the sensitivity.

Table 24 - Results of sensitivities (£bn)

Sensitivities	**Baseline**	**Sensitivity 1**	**Sensitivity 2**	**Sensitivity 3 / Comparison**
CM Drop-out	No drop out	Medium drop out	High drop out	*Grandfathering WACM13 comparison*
(based on Avoided GSP Phased (£7.5bn))	7.5	7.3	6.9	*6.9*
		-0.3	-0.6	*-0.7*
Capex (C) Efficiency of Gas Recips (E)	C: BEIS Low E: (+0%) 32%	C: BEIS Medium E: (+0%) 32%	C: BEIS Medium E: (+5%) 37%	C: BEIS Medium E: (+10%) 42%
(based on Avoided GSP Phased (£7.5bn))	7.5	7.6	7.5	7.8
		0.0	-0.1	0.3
Avoided GSP	Baseline £1.62	Increased £5.00		
(based on Avoided GSP not-phased (£7.7bn))	7.7	7.0		
		-0.8		

6.27. The modelling suggests CM drop out does not lead to a significant reduction in consumer savings. The high drop-out scenario, which would see 1152MW of plant drop out of the CM (of the 7.5GW of EG assumed to run at triad), leaves a consumer benefit of £6.9bn. This drop-out leads to replacement cost and market impact and increased consumer costs of £625m. In cases, the replacement cost and market impacts are, in fact, lower than the equivalent loss to consumer savings which we estimate results from grandfathering of CM14/15 plant.

6.28. Regarding the capex and efficiency runs, increasing capex alone from the BEIS Low to BEIS Medium figures gives greater savings. This is due to OCGTs replacing reciprocating engines as the higher capex costs for OCGTs are proportionally lower at those cost assumptions.

6.29. Unilaterally increasing efficiencies of gas reciprocating engines has little impact, as gas reciprocating engines are not built in sufficient quantities for the increased efficiency to impact the results under these scenarios. In the baseline scenario using BEIS Low capex assumptions, CCGT tends to be built under scenario 3. With higher capex (and efficiencies for reciprocating engines), OCGTs play a greater role. Due to the higher thermal efficiency of reciprocating plant assumed in this scenario however, we would expect to see similar consumer savings if it were to be gas reciprocating plant which were eventually built rather than OCGTs, as this set of assumptions implies.

6.30. Finally, changing the level of the avoided GSP infrastructure has a relatively small impact on the consumer benefits, but suggests that a higher level of avoided GSP cost would not change the direction of benefits (though may reduce the difference in consumer savings between modification proposals). It is worth noting that the avoided GSP is intended to be a cost-reflective benefit (though we do outline some comments on its non-locational nature in earlier chapters) and so if cost reflective, the correctly level should lead to the efficient level of network investment on both transmission and distribution systems.

Modelling results – Detailed view of shortlisted options

6.31. In this section, we set out the updated modelling results for the shortlisted options. We then present other impacts using 'Scenario 3' as an example. Further information on the other scenarios is set out in in appendix 4.

6.32. As a general rule, grandfathering and phasing options deliver lower benefits to consumers than options without transitional arrangements and higher benefits are observed in options that have lower payments to smaller EG. All options provide a benefit to consumers compared to the status quo. 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 25 - Consumer and system cost savings for selected options

WACM Number	Modelling option	Consumer cost saving 2016- 2034 (Real, £bn)	System cost saving 2016- 2034 (Real, £bn)
WACM3	Scenario 3	7.7	1.9
WACM4	Scenario 3 with phasing	7.5	1.9
WACM4 + Delay (estimate)	Scenario 3 with phasing - c.£0.5mn delay cost	c.7.0	c.1.9
WACM5	Generator residual with phasing.[97]	6.4	1.8

[97] Not including the additional value of £1.62/kW.

6.33. All of the options shortlisted provide a significant consumer and system cost saving.

Consumer and System cost saving – shortlisted WACMs

6.34. Consumer cost savings, as set out in the Frontier/LCP supplementary modelling report[98] that accompanied our minded to decision and draft impact assessment, include the cost savings from not paying the TDR to embedded generators, CM payments, wholesale and CfD costs, and the cost of unserved energy[99]. System cost savings cover fuel, variable opex, carbon prices, plant capex, and unserved energy. More information can be found in the supplementary modelling report. There may be additional effects on network costs, as additional transmission or distribution network investment may be triggered by plant coming on to the system. However, new plant may use existing or recently decommissioned connections, and may not require significant network investment. The location of new plant could also significantly impact the amount of new investment needed. Due to this unpredictability, the modelling would be very sensitive to input assumptions, and so network costs are not modelled.

6.35. 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.

6.36. The annual consumer cost savings of WACM4 are shown in the chart below. WACM4 leads a consumer saving in the years to 2024 of £2.2bn, and £7.5bn in the years to 2034. The consumer cost savings are similar for WACM3 and WACM4. WACM5 leads to lower savings due to the higher payments to smaller EG. More information of those options that were not shortlisted, and for modelled scenarios 1 and 2, is available in appendix 4.

[98] https://www.ofgem.gov.uk/system/files/docs/2017/03/lcp_frontier_-_supplementary_modelling_report.pdf, sections 4.11 and 4.12
[99] Assigned a cost of £17,000/MWh

Figure 9 - WACM4 Consumer cost savings[100]

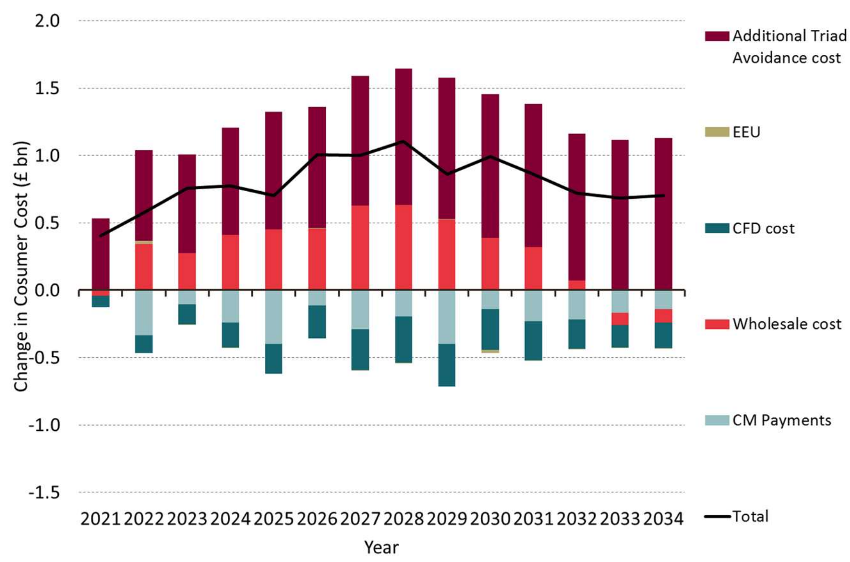
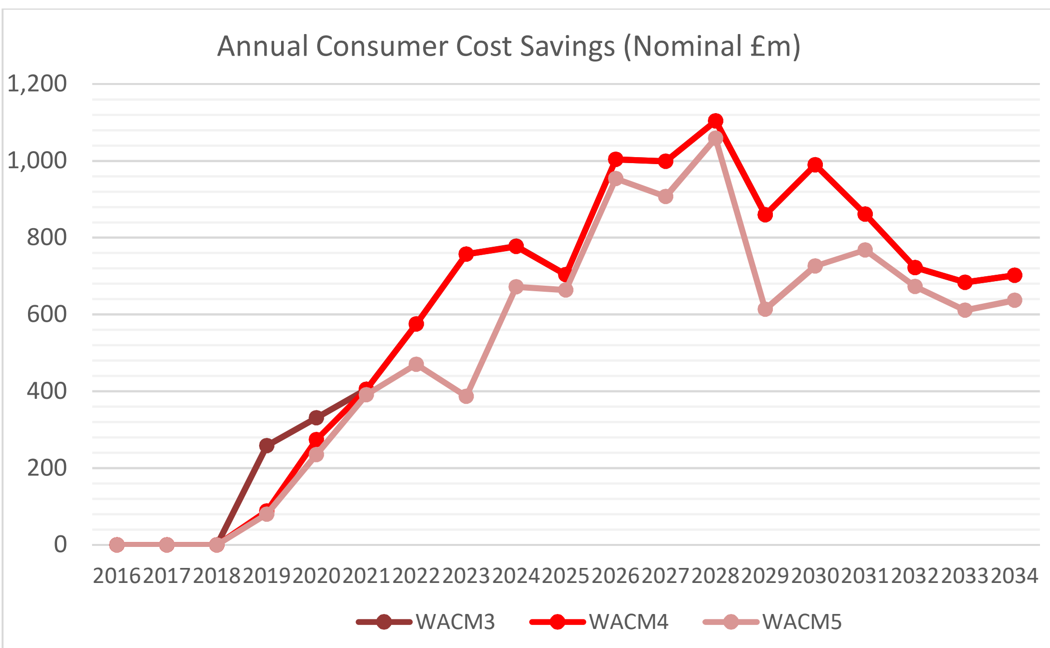


Figure 10 - Nominal consumer cost savings of WACMs 3, 4 and 5



[100] In this graph, positive numbers indicate consumer savings, and negative numbers indicate additional costs to consumers

6.37. The system cost savings for WACM4 are shown below, as well as the nominal system cost savings of WACM 3, 4 and 5.

Figure 11 - WACM4 system cost savings[101]

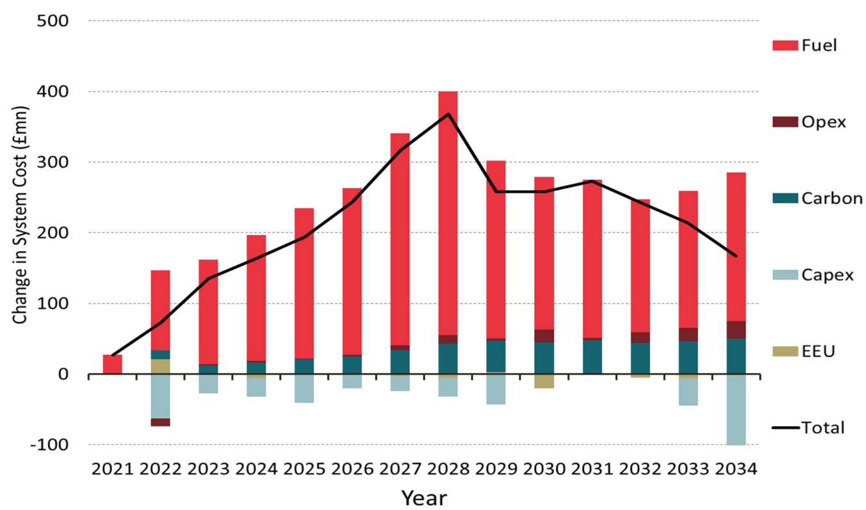
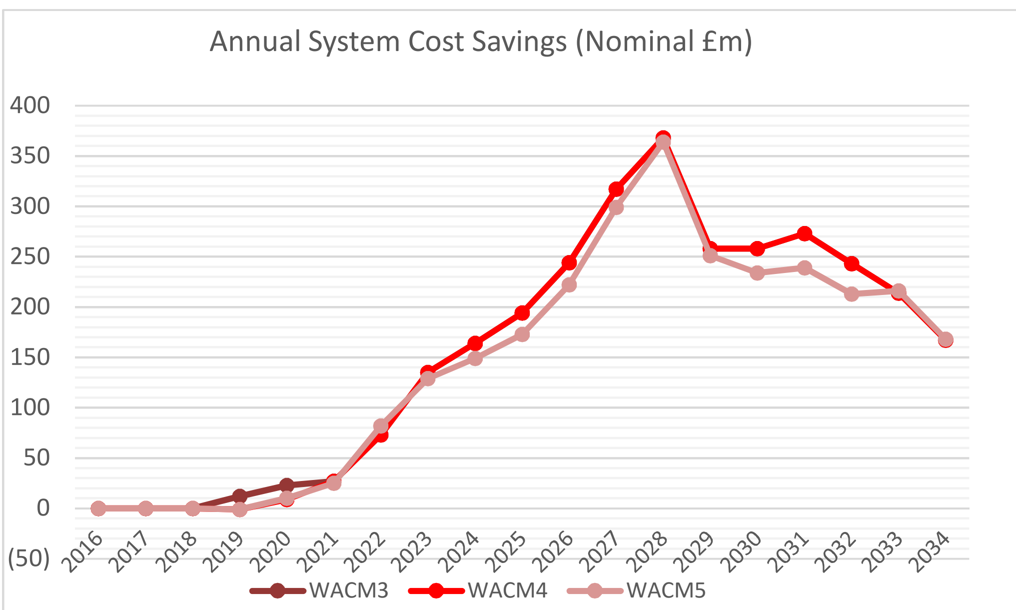


Figure 12 - Nominal system cost savings of WACMs 3, 4 and 5



[101] In this graph, positive numbers indicate consumer savings, and negative numbers indicate additional costs to consumers

6.38. The majority of savings in system cost are driven by a reduced fuel usage for power generation and some opex savings. Under WACM4, new CCGT plant come online, replacing older and less efficient existing CCGTs. This increased efficiency leads to lower system costs overall.

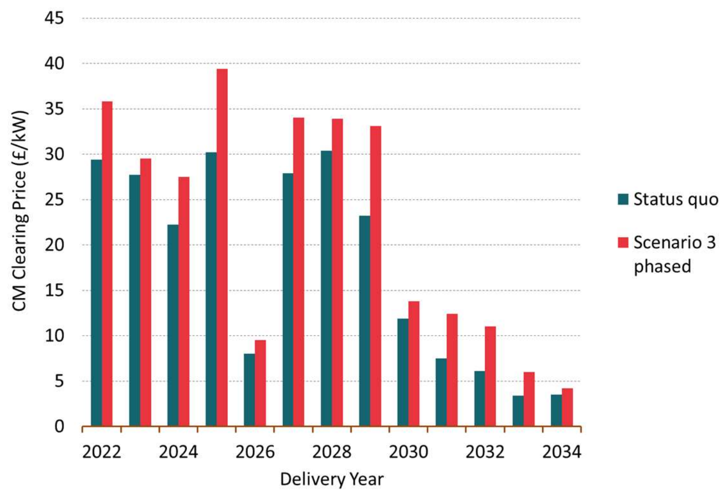
Security of supply impacts – Scenario 3 phased (WACM4)

6.39. The below chart shows the modelled level of estimated Loss of Load Expectation (LOLE) that is seen under WACM4 (Scenario 3 phased). This estimates the effect on security of supply. 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 the EnVision results. Both assessments suggest that the impact on security of supply is likely to be limited, and estimated as being within the Government's reliability standard of 3 hours/years for all the options modelled.

Figure 13 - WACM4 Loss of Load Expectation compared to Status Quo

6.40. We do not consider there to be a material security of supply risk but acknowledge there may be an increase in capacity market clearing prices. The below chart sets out the likely impacts on the capacity market clearing price, for WACM4.

Figure 14 - Capacity Market clearing price comparison between WACM4 and Status Quo



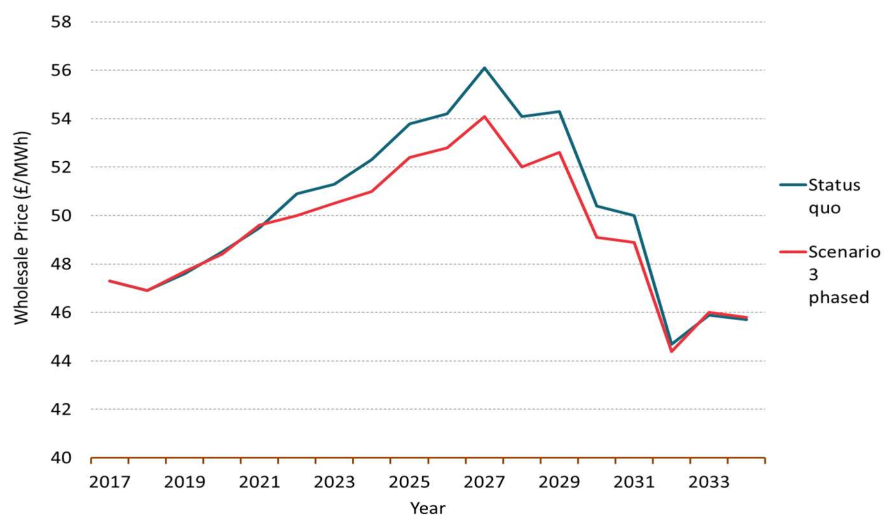
Our own analysis[102] suggests the early delivery years of the CM (2018/19 and 2019/20) are likely to be the most impacted by the reform, due to the risk that some new build reciprocating engines do not build based on these contracts. There is a risk that if some distribution-connected plant do pull out of existing CM contracts, this may take capacity out of the CM for multiple years, due to the rule that "sterilise" such capacity[103]. If the assets are taken on (or completed) by another operator, there will not be an impact. Where sites are sterilised, this should not present a risk to security of supply if other sites are available and can be utilised by the time that capacity is needed, though this may come at additional cost. The cost impact of generation pulling out is shown in the CM drop-out sensitivity.

Wholesale price impact

6.41. The below graph shows that wholesale price impact of a move to WACM4. This shows the average wholesale cost decreasing, compared to the 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.

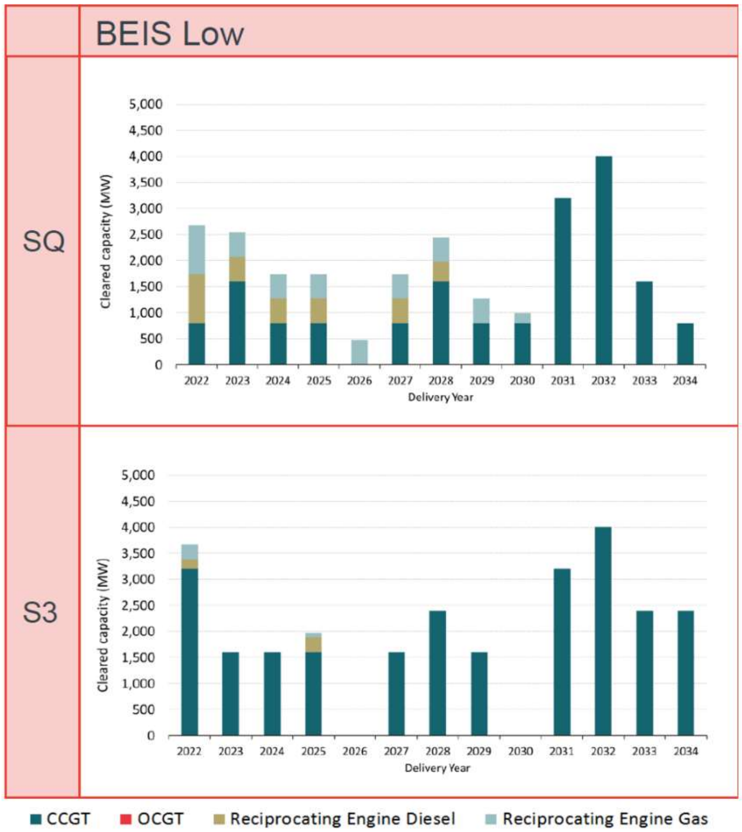
[102] Ofgem's own analysis extends to winter 2020/21.
[103] Termination fees are also payable

Figure 15 - Impact of WACM4 on wholesale price as compared to Status Quo



6.42. Under the status quo, using the BEIS Low capex assumptions, large volumes 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. Under WACM4 more CCGTs are built, leading to lower wholesale prices and higher CM prices. Sensitivities using higher capex assumptions are discussed in the sensitivities section below.

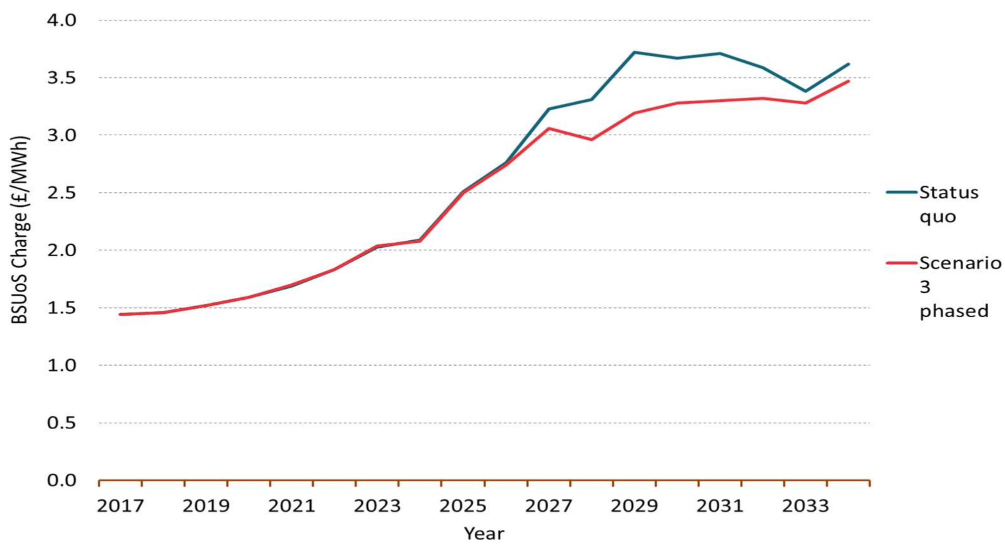
Figure 16 - Capacity Market build out under Status Quo and Scenario 3



BSUoS charges impact

6.43. Balancing costs remain similar for the status quo and Scenario 3 phased (WACM4) until the early 2020's, after which point the balancing costs for scenario 3 phased (WACM4) rise at a lower rate compared to status quo. 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.

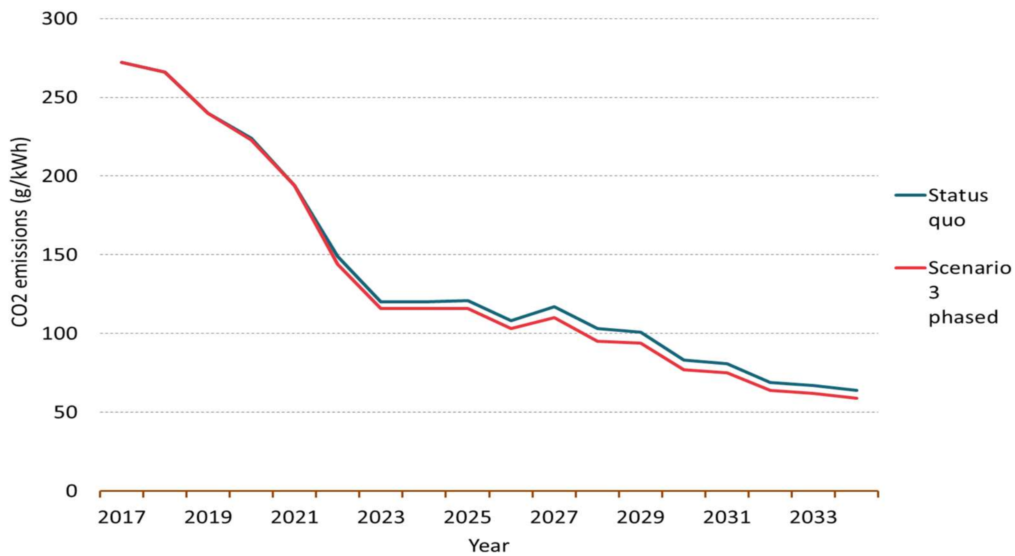
Figure 17 - Impact of WACM4 on balancing costs as compared to Status Quo



CO_2 emissions impact

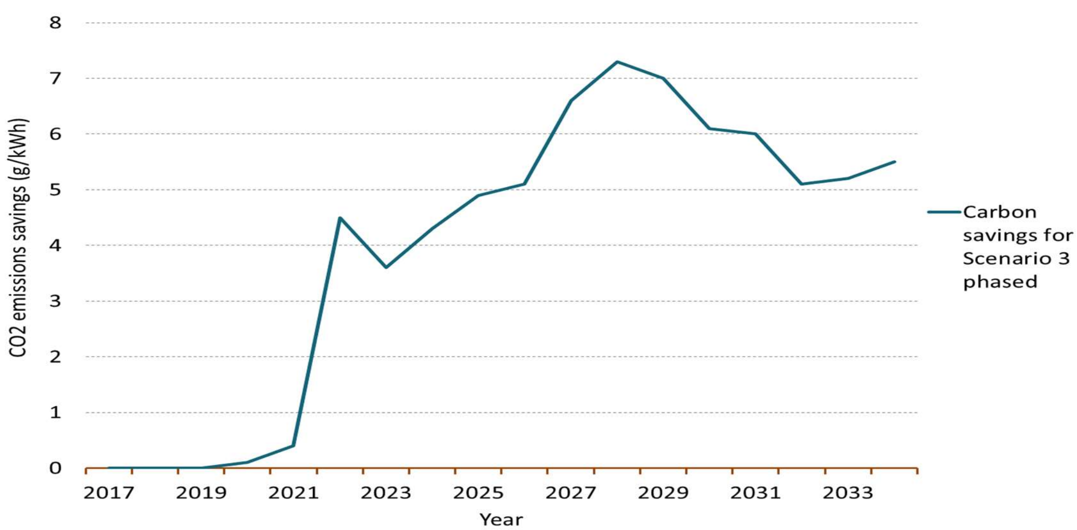
6.44. Scenario 3 phased (WACM4) leads to a small reduction in carbon emissions due to more efficient CCGT plant coming forward in the CM. The overall downward trend is due to the increased renewable build out and the coal closures, in the background FES scenarios.

Figure 18 - WACM4 CO2 emissions (g/kWh) compared to Status Quo



6.45. The graph below shows the CO_2 savings on a g/kWh basis, compared to status quo, of the leading option.

Figure 19 - WACM4 CO2 savings (g/kWh) compared to Status Quo



Sensitivities and stakeholder modelling feedback

6.46. Following requests from stakeholders, we published the Frontier/LCP modelling report and associated data that supported our impact assessment and held a workshop to discuss the modelling with stakeholders with the aim of ensuring that stakeholders had the information they needed to make meaningful representations. We also consented to, and attended as an observer, a workshop held by Frontier/LCP run for certain stakeholders with the aim of ensuring that the modelling was well understood.

6.47. Through the workshops and consultation responses we have received a number of comments on our modelling and took the decision to undertake further modelling on a small number of areas.

Sensitivities - Capex and efficiencies commentary

6.48. As noted above, we undertook a range of modelling runs to better understand how sensitive the model was to various sets of input assumptions. These focused on:

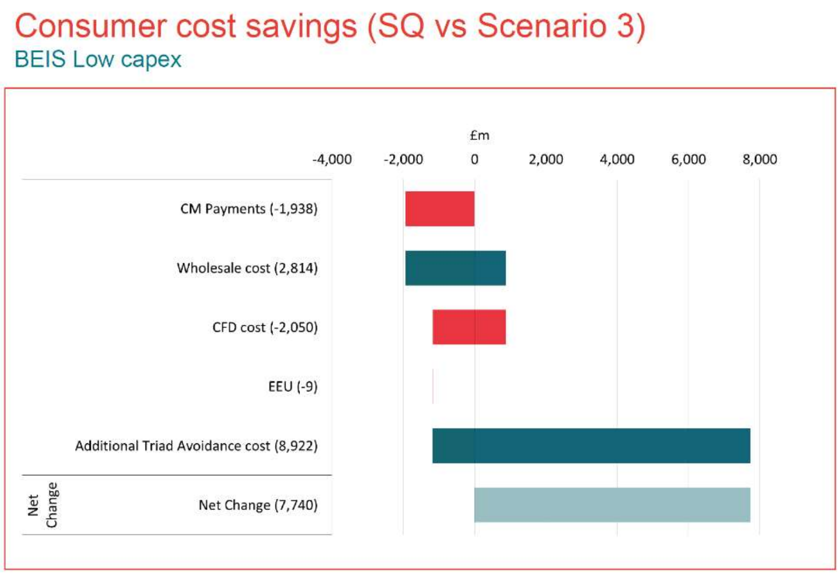
a. Changes in capex assumptions

b. Changes to efficiency assumptions of gas reciprocating plant, and;

c. Changes to the level of the avoided GSP.

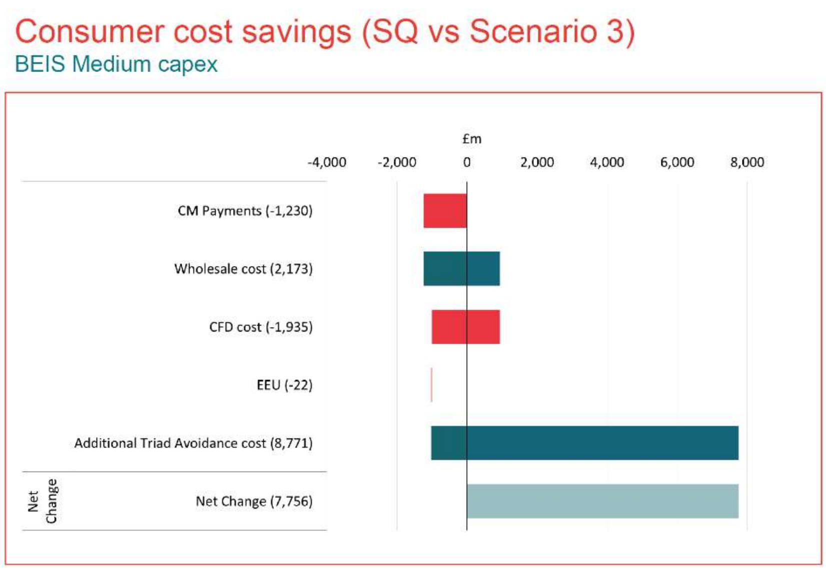
6.49. The chart below shows the consumer cost changes for the baseline run (Low capex, Low efficiency) for Scenario 3 (WACM3, or effectively WACM4 without phasing). This shows that while there are increase costs from CM and CfD payments, these are much smaller than the consumer savings from not paying the TDR revenues to smaller EG, and from lower wholesale costs in the long run.

Figure 20 – WACM3 consumer cost chart with low capex assumption



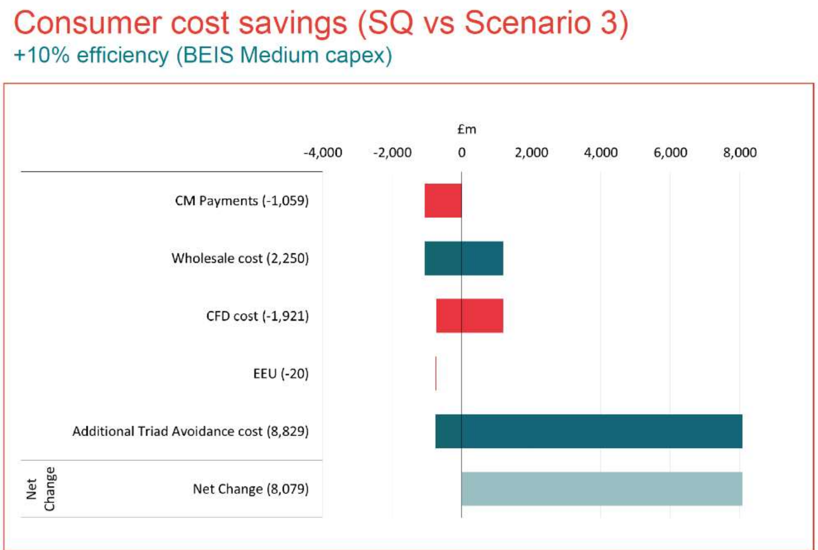
6.50. As shown below, moving to BEIS Medium capex has little impact on the savings.

Figure 21 - WACM3 consumer cost chart with medium capex assumption



6.51. Finally, increasing the efficiency of the reciprocating engines has little impact, though does increase consumer savings[104].

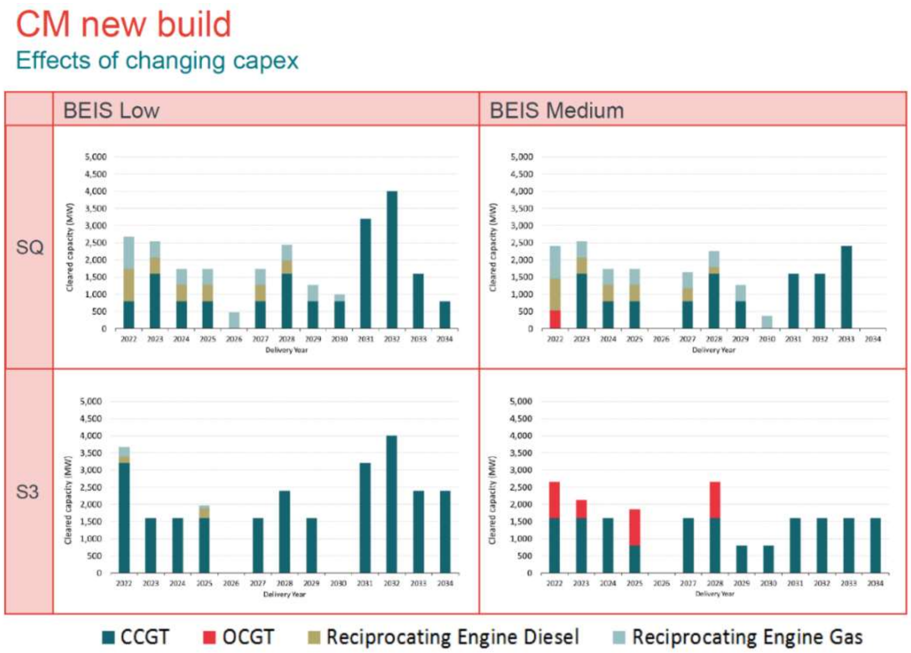
Figure 22 - WACM3 consumer cost chart with medium capex assumption and higher (10% efficiency)



6.52. This can be explained by the fact that changing capex only led to slightly different buildout. In low-TDR scenarios OCGTs replaced reciprocating engines, so higher efficiency does not make a large difference.

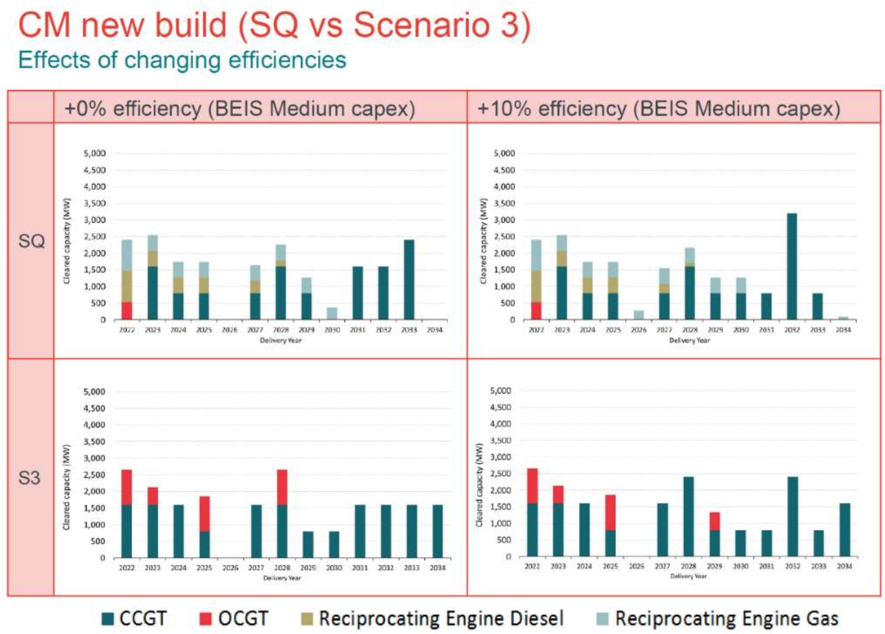
[104] All efficiency sensitivities used a 54% efficiency for CCGTs.

Figure 23 - Effect of increased capex on capacity market build



6.53. Moving to higher efficiencies had little impact, delivering similar plant mix (but not exactly). This suggests that at the capex levels tested, the efficiency of a reciprocating engine is not material to the results in scenarios where the level of embedded benefits is reduced.

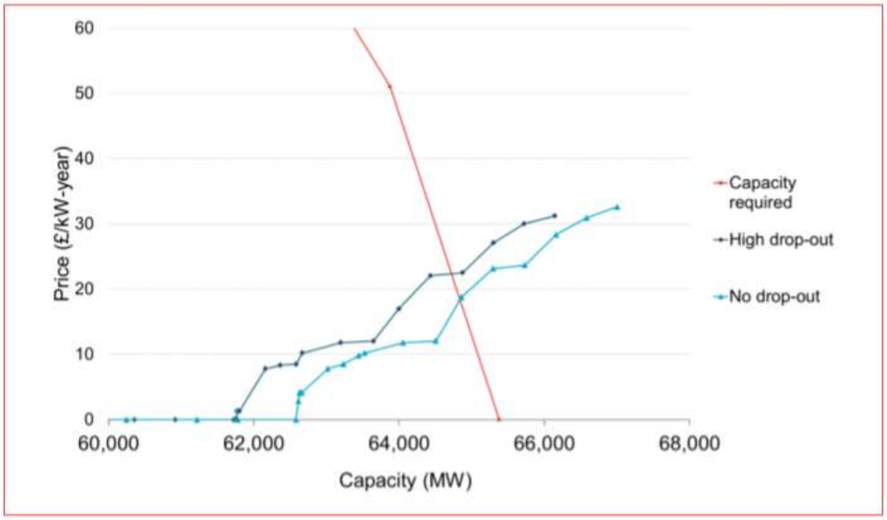
Figure 24 - Effect of increased capex and reciprocating engine efficiency on capacity market build



Sensitivities – CM drop-out commentary

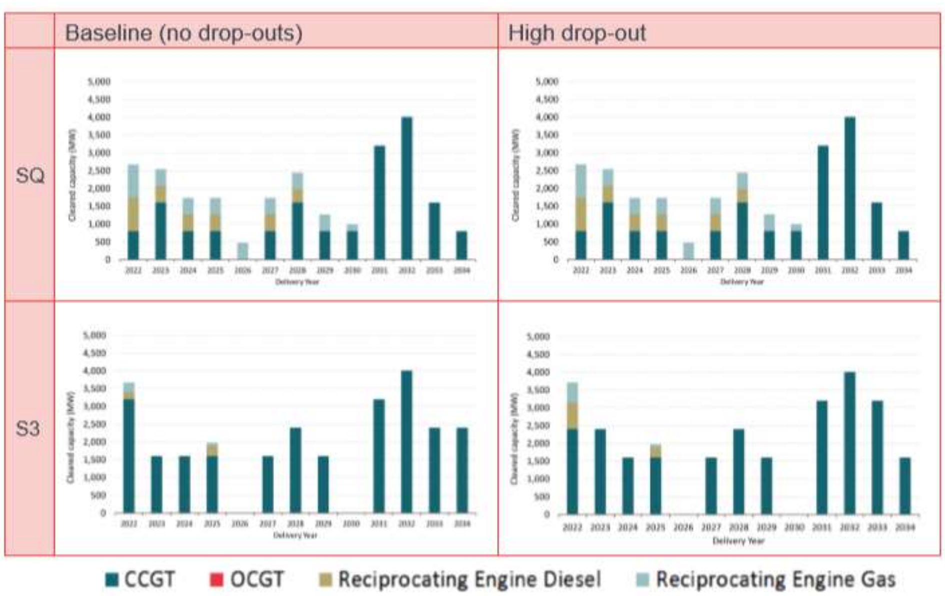
6.54. Moving on to the scenarios that modelled the impact of CM drop out, higher drop-out rates increased the capacity procured in the first T-1 auction and increased the clearing price by a small amount. This led to a decrease in the consumer cost savings, though not of a significant amount. This scenario does not model additional drop out of plant in future CM years, as to do so plant would again need to renege on their contracts.

Figure 25 - Capacity Market clearing price with 'high drop out' scenario'



6.55. Some of the effect is ameliorated by higher levels of more efficient plant in later years and the modelling suggests replacement cost is lower than grandfathering cost (WACM4 high drop-out (£6.9bn) grandfathering under WACM13 (which doesn't have phasing) (£6.8bn). In our modelling more diesels and gas reciprocating engines clear to replace the plant lost, and CCGT that would clear in one year partially move into the next year.

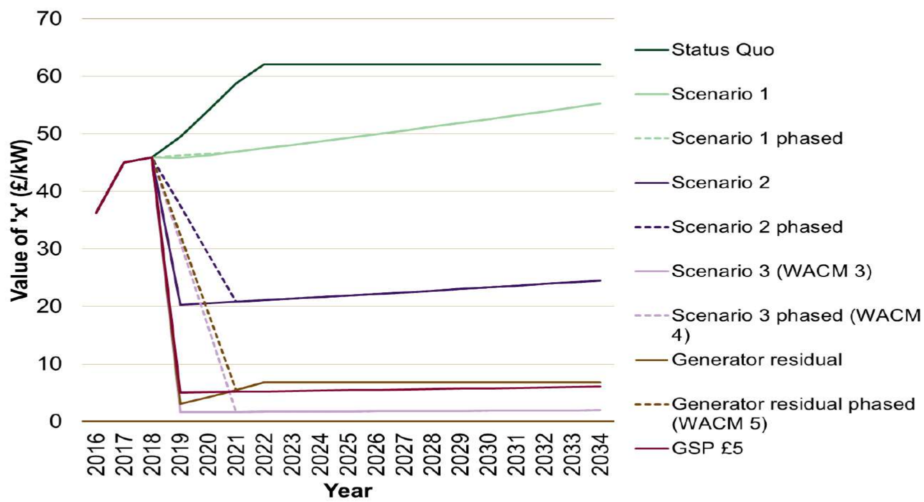
Figure 26 - Capacity Market build with 'high drop out' scenario



Sensitivities – Avoided GSP Sensitivities commentary

6.56. Running a higher avoided GSP value of £5 reduced the consumer cost savings by £0.8bn in a non-grandfathered scenario, as higher payments are made to generators. It should be noted that a higher avoided GSP cost, if cost-reflective, would reduce consumer savings but would be matched by reduced transmission system build. Overall the NPV was still high.

Figure 27 - Modelled level of 'x' according to scenario



7. Assessment of shortlisted options

Chapter Summary

In this section we assess the shortlisted options more likely to best facilitate the CUSC objectives and our statutory duties, and conclude which option best facilitates the CUSC objective and our statutory duties.

7.1. In this section we assess the three shortlisted options from Section 4, with the additional option of accepting WACM4 with an additional one year delay, taking account of:

- the key CUSC objectives – cost reflectivity and facilitating competition – set out in Section 4
- our wider statutory duties – set out in Section 4
- distributional impacts –set out in Section 5
- our quantitative modelling results – set out in Section 6

Shortlisted options assessed

7.2. The three shortlisted options identified in Chapter 4 and an additional option of accepting WACM4 with a one year delay are set out below. We have assessed the option of accepting WACM4 with a one year delay due to a number of respondents who indicated they would support a substantial delay to the implementation of any new arrangements. We considered it important to consider if any further delay to the implementation of our minded-to decision to accept WACM4 could be in the interests of consumers.

Table 26 - Summary of shortlisted options assessed

WACM 3	WACM 4	WACM 4 with 1-year delay	WACM 5	Status Quo
WACM 3 removes net charging for all smaller EG and replaces with 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 smaller EG, and replaces with a payment of a value equal to the value of avoided GSP investment according to NG's last estimate.	This option implements WACM 4 with a one year delay.	WACM 5 removes net charging for all generators, and replaces with a payment of a value equal to the value of avoided GSP investment, plus the generation residual.	Net charging remains. TDR increases to around £69/kW by 2021/22. Conservative modelling suggests by 2034 the cost of these payments to smaller EG could exceed £1.1bn p/a.
Immediate Implementation	Phased Implementation from 2018 to 2020	One year delay and phased implementation from 2019 to 2021	Phased Implementation from 2018 to 2020	Current Regime

Review against CUSC objectives and our wider statutory duties

7.3. In Section 4 we undertook a detailed assessment of the options in front us against the CUSC objectives and our wider statutory duties. We found that two important CUSC objectives in relation to this decision are cost-reflectivity and competition.

7.4. Our analysis indicates there is not a strong economic rationale to justify the current level of TDR payments to smaller EG. Removing these payments, and replacing them with an appropriate payment for savings smaller EG can bring to the system would be more cost reflective and less distortive to competition. Our assessment is that WACMs 3 and 4, with their reduction to the avoided GSP costs, and WACM 5 which also adds the TGR, are more likely to lead to significant improvements in cost-reflectivity and competition and to meet our statutory duties when compared to the status quo and other options.

7.5. Two attributes we have considered are the value of 'x' and the method of implementation.

Value of 'x'

7.6. Our analysis and the evidence presented to us indicates that the payment of avoided GSP costs was found to be a benefit that smaller EG can bring to the system, and hence should be included in payments received by smaller EG.

7.7. Of particular benefit of this approach is the fact that this avoided GSP value will be reset by National Grid at the time of implementation and also at the beginning of every price control, with RIIO infrastructure costs, allowing the payment to maintain cost-reflectivity over time. If the value of this factor is found to be greater in future, higher payments will 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. 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.

7.8. Including the TGR in the value of 'x' to be paid to smaller EG could in principle improve competition between smaller EG and other generation. As there is evidence that EG affects flows on the transmission system in a similar way to transmission connected generation, it could be argued that EG should be exposed to transmission charges. We are separately consulting on which network users should pay residual charges on transmission and distribution networks as part of the TCR. We note that all EG is exposed to the transmission locational signals. The proposals put to us, however, mean that WACM 5 is likely to bring 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. This is because:

a. The TGR would be paid on a triad basis, and therefore act as a further distortive incentive for smaller EG to run at triad period.

b. The floor at zero element to the modification means that if the TGR returns to a positive charge, it will dampen locational signals seen by smaller EG. If the TGR were to increase to a figure above the highest locational charge, smaller EG would face no locational signals.

c. The flooring elements also leads to asymmetric distortions. The TGR payments/charges to smaller EG would be the same across generators type when the TGR is negative, but would effectively act as an embedded benefit when positive.

7.9. The fact that WACM 5 would expose smaller EG to the TGR in a fundamentally different manner to other forms of generation due to the 'floor at zero' arrangements, reduces the extent to which the inclusion of the TGR would improve competition. Moreover, as set out in Section 4, we think that the treatment of the generation residual should be reviewed as part of the TCR.

Implementation

7.10. In terms of implementation, WACM3 offers the most immediate change, WACMs 4 and 5 phase change over three years from 2018 and WACM4 with a one year delay ("WACM 4+1") would phase change over three years, starting in April 2019[105].

7.11. WACMs 4, 4+1 and 5 would lead to more delayed consumer benefits and a continuation of some competitive distortion for a short period of time, but will allow a 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. We do not expect a material impact on security of supply as the T-1 auctions are available to ensure capacity is available. 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.

7.12. The use of phasing options was supported by stakeholders, including several distribution network operators and National Grid. We consider the phasing options, WACMs 4, 4+1 & 5 to be more likely to best facilitate the CUSC objectives and our statutory duties than WACM3, which has immediate (unphased) implementation.
In addition, we have assessed the option of WACM 4+1. Our analysis indicates that a further delay to implementing WACM4 would significantly increase costs to consumers, in the region of £0.5bn compared to WACM 4.

Table 27 - Cost of implementation options

Implementation (vs WACM4)	Cost (£m)
Phased from April 2018	0.00
Delayed implementation 1yr	c.500.00
Grandfathering at £45.33	659.00

7.13. We recognise that implementing the reduction to the TDR payments within one year (as WACM 3 would require) would mean a significant change within one charging year, and hence we accept that, in this case, accepting a mod (WACM 4) to allow a phased transition over three years is merited. The phased transition provided by WACM4 also provides a gradual reduction in TDR payments over three years, which prevents a large decrease in TDR payments in any single year. However, delaying the implementation of WACM 4 by a year would add a very significant amount of costs to consumers and also delay to the delivery of the

[105] The phasing and grandfathering options available to Ofgem are fixed methodologies, as set out by the legal text for each of the CUSC proposals and WACMs, so no additional forms of grandfathering or transitional arrangements can be proposed. 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.

benefits to competition and the more efficient functioning of markets. We have not seen any evidence to suggest that the benefits of such a delay would balance against the substantial increase in costs.

Review of Distributional Impacts

7.14. Section 5 set out our assessment of the distributional impacts of the options in submitted to us. We expect that a reduction in the TDR to the avoided GSP cost to lead to reduced revenues for affected smaller EG. Those most significantly impacted by will be non-intermittent plant, and in particular those plant whose business model focuses on hitting the triad periods. Those smaller EG which have a high load factor will also see a high impact on their revenue streams. Solar generators will not be impacted by these proposals, while wind farms will see a moderate decline in revenue streams, due to the low load factor generally recorded by wind farms at system peak demand.

7.15. The spread of impact across technology type is the same in WACMs 3, 4+1 & 5. All the proposals replace the TDR payments with a payment linked to triad, meaning the relative impacts are linked to generators' ability to run at the triad periods. Overall revenue losses will be marginally be lower in the case of WACM5.

7.16. Some flexible plant (including storage) at embedded level will receive reduced revenues, which may increase ancillary service costs, though these increases should result in a more efficient price level, and stronger competitive pressures to provide these services. In contrast, the "do nothing" option, where the status quo is retained, would lead to increased revenues for these operators at the expense of consumers and efficient market function.

7.17. As outlined above we believe that there is likely to be a large saving in consumers costs of a reduction in TDR payments. 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.

7.18. We 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. £47.30/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

7.19. We do not consider WACM3 to have a material impact on security of supply, but believe that 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 for the system operator to monitor and predict. This is desirable, and when combined with the additional time for generators and investors to adjust their business models and the relatively low reduction in consumer savings[106], a phased option seems well justified. This additional period may assist operators in finding replacement revenue streams. Phasing also does not provide different arrangements for different classes of smaller EG, such as between existing and new users.

7.20. WACM3, which brings about immediate change, gives generators and investors less time to adjust their business models, leading us to conclude it would be less likely to best facilitate the CUSC objectives. WACMs 4, 4+1 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 investors, who should be familiar with the Ofgem statutory objectives and the CUSC code objectives before making any investment.

Summary of quantitative modelling assessment undertaken

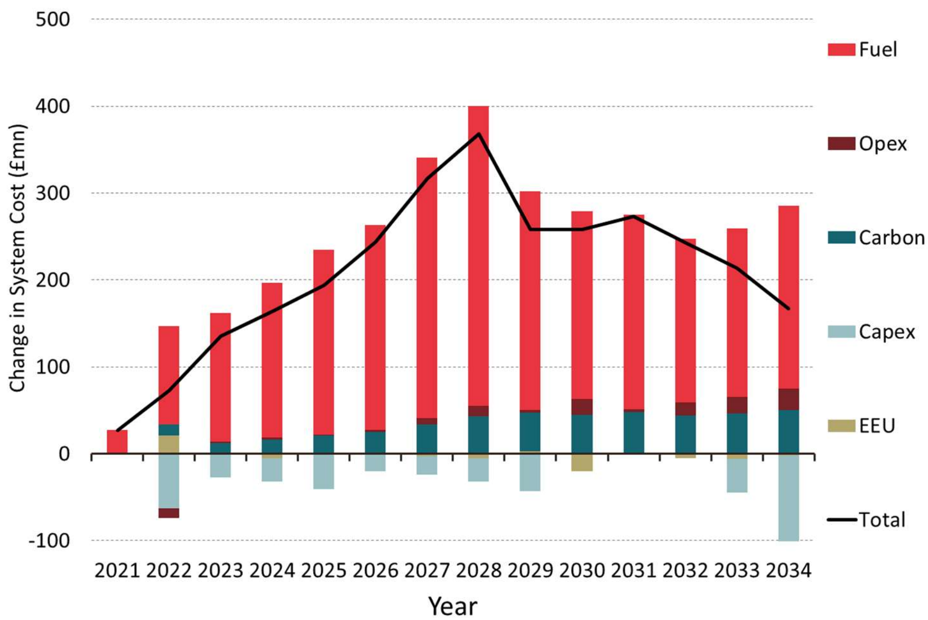
7.21. In Section 6, we described the quantitative modelling we undertook to support our principles-based assessment of the options.

7.22. Each of the options we have shortlisted for further consideration lead to substantial system cost savings. As noted in Section 6, our assessment has primarily been a principles-based qualitative assessment and the modelling has been used for context and to help us understand potential impacts of the proposals. Ofgem has not relied on the modelling as the sole or predominant basis for our decision. We must balance the elements of the different proposals to reach a conclusion as to which – if any – of the shortlisted options best facilitate the CUSC objectives and are consistent with our statutory duties.

7.23. As well as reducing payments to smaller EG, the costs of which are borne by consumers, WACMs 3, 4, 4+1 and 5 result in a significant reduction in system costs, predominantly from fuel savings, but also from reduced emission costs. As previously noted, there may be additional effects on network costs which are not modelled.

[106] We estimate the cost to be around £200m, which although large, is only a small percentage of the consumer savings that will potentially be delivered.

Figure 28 - System cost savings[107], WACM4 against Status Quo



7.24. The “do nothing” option is likely to be harmful for competition. The TDR is forecast to increase to £69/kW, meaning a significant revenue stream will be available to some smaller EG that is not available to larger EG or to TG. Under WACM3 and 4, we believe competition between generation is likely to be much improved, as there will be a greatly reduced incentive to inefficiently connect generation at the distribution level. We also believe that the exposure of smaller EG to the TGR may lead to an improvement in competition against the status quo, though as discussed above, WACM 5 may bring some competition benefits if the TGR is negative, but would be likely to be worse when the TGR is positive.

7.25. We have previously communicated our concern with a situation where the generation residual is negative. One driver for this is the current €2.50/MWh cap on generator use of system charges, mandated by EU law. As discussed earlier, we have recently consulted on the use of our Significant Code Review (SCR) powers to launch a Targeted Charging Review. This review will lead to changes in how residual charges are levied and recovered.

7.26. 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, 4+1 and 5, CM bids are likely to be more cost reflective. WACMs 4 and 5 will take longer to reach this cost reflectivity due to phasing, and WACM 4+1 longer still, though we consider there are benefits of

[107] In this graph, positive numbers indicate consumer savings, and negative numbers indicate additional costs to consumers

phasing. More cost-reflective bids are likely to lead to more efficient plant investment.

7.27. 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. 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

7.28. Under WACMs 3, 4, 4+1 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 TDR payments smaller EG, something which is supported by our modelling. In the long term, a more competitive market that is more supportive of innovation is likely to lead to further 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.

Figure 29 - Consumer costs savings[108], WACM4 against to Status Quo

7.29. Overall, as supported by the results of our modelling, we expect WACMs 3, 4, 4+1 and 5 to bring significant cost savings to both the system and consumers.

7.30. 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 several years. Industry participants and energy consumers that have made investment decisions that assumed continued payments from the network charging system may find that those investments are uneconomic without them. The effect of these changes on CM plant, and the potential for plant to drop out, is set out in chapter 6.

7.31. The tables below provides a summary of the shortlisted options, their assessment against the CUSC objectives and the modelling results. The assessment of these options against our wider duties and taking account of distributional impacts in described in Chapters 4 and 5.

[108] In this graph, positive numbers indicate consumer savings, and negative numbers indicate additional costs to consumers.

Summary of short-listed options

		WACM 3	WACM 4	WACM 4 + 1 year delay	WACM 5
Description of option	Value of 'x'	Avoided GSP	Avoided GSP	Avoided GSP	Avoided GSP + TGR
	Implementation	Immediate, implement in 2018	Phased over three years from 2018	Delay then phased over three years from 2018	Phased over three years from 2018
CUSC objectives	Cost reflectivity	• Avoided GSP rationale most robustly justified as cost reflective, reflects EG cost savings achievable • Immediate cost-reflectivity achieved	• Avoided GSP rationale most robustly justified as cost reflective, reflects EG cost savings achievable • Phasing means cost-reflectivity achieved more slowly	• Avoided GSP rationale most robustly justified as cost reflective, reflects EG cost savings achievable • Delay and phasing means cost-reflectivity achieved even more slowly	• Avoided GSP rationale robustly justified as cost reflective • The TGR in not a cost reflective element • Floor at zero means if TGR positive, EG likely will not pay same as TG • Phasing means cost-reflectivity achieved more slowly
	Facilitating competition	• Avoided GSP's cost-reflectivity likely to lead to most improved competition • However, leaves little time for affected smaller EG to adjust business models	• Avoided GSP's cost-reflectivity likely to lead to most improved competition • Phased implementation gives time for smaller EG to adjust business models • Phasing means competition benefits achieved more slowly	• Avoided GSP's cost-reflectivity likely to lead to most improved competition • Delay and then phasing means an extended period before full benefits realised	• Avoided GSP's cost-reflectivity likely to lead to improved competition • But TGR as proposed would add a further distortion, meaning there are different behavioural incentives • Phasing means competition benefits achieved more slowly
Estimate of impacts	**NPV consumers**	**7.7**	**7.5**	**7.0**	**6.4**
	NPV system savings	**1.9**	**1.9**	**1.9**	**1.8**
Overall assessment		**Better facilitates**	**Best facilitates**	**Better facilitates**	**Better facilitates**

Avoided GSP (Last calculated at £1.62/kW (2013/14), current estimate £3-7/kW (2017/18))
TGR (currently £1.85/kW (2017/18))

Summary of overall assessment of shortlisted options

7.32. Weighing up the improvements to cost reflectivity and competition, with the potential impact on consumers and market participants, we consider the adoption and implementation of WACM4 to best facilitate the CUSC Objectives and Ofgem's Statutory Duties.

7.33. Our view of the options submitted to us is that we expect WACM4 to be in the best interest of customers. We think that its use of a 3-year phased implementation means, on balance, it is more suitable than WACM3, and we think that the limitations of the proposed changes to the TGR, alongside the proposed launch of the TCR, means WACM5 may not be the best option. We believe WACM4 better balances the interests of customers and investors. 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. We do not think the additional costs to consumers and impact on competition of implementing WACM4 with a one-year delay are merited.

7.34. Any decision on transitional arrangements, in the form of phased transitions or otherwise, will be made independently and there should be not be any assumptions that future changes will be implemented on a phased basis, nor should this be seen to establish a precedent. Instead, our final view is that phased change is appropriate in this case.

Table 28 - Overall assessment of options

CUSC Objectives and Ofgem's Statutory Duties	
WACM Number	**Better facilitate CUSC objectives**
WACM4	Best Facilitates
WACMs 3, 5, 4+1	Likely to better facilitate
264, WACMs 1, 2, 6-19, 23	Less likely to best facilitate
265	Neutral
WACMs 20-22	Do not better facilitate

8. Conclusion – final decision

Chapter Summary

Here we set out our final view that WACM4 best facilitates the CUSC objectives and our statutory duties.

Decision

Our final view is that WACM4 best facilitates the CUSC objectives and our statutory duties

8.1. Our decision is to direct that WACM4 be made. The level of payment to smaller EG should be reduced to the avoided GSP costs, and we believe a phased approach over three years 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.

Implementation

8.2. As noted above, we believe the most appropriate implementation route is a phased implementation over three years starting from the next charging year. We note that some stakeholders, notably National Grid, oppose a mid-year tariff change. We understand that National Grid and Elexon consider an April 2018 implementation to be feasible. We have received responses that note that there will be a need for supplier and industry system changes. As tariff changes each year are confirmed with 60 days' notice, we would expect suppliers to be able to make the necessary changes. The legal text has been available since the workgroups for them to use to assess how they would adapt their systems, and the contractual frameworks in use with EG should reflect the changing nature of the industry charging regime.

8.3. We have considered the possibility of delayed implementation to WACM4. We consider that while this may bring additional benefits to investors and reduce the implementation risk, the consumer cost, which we estimate at c. £500mn, is too high. We are also concerned that delay would retain the current distortions for a further year, increasing the potential for negative impacts on the markets.

8.4. We therefore consent to the implementation of WACM4 with immediate implementation, with the first reduction in payments to smaller EG applicable from April 2018.

Decision Direction

In accordance with Standard Condition C10 of NGET's Transmission Licence, the Authority, hereby directs that WACM4 of modifications CMP264 and CMP265 be made.[109]

[109] This document is notice of the reasons for this decision as required by section 49A of the Electricity Act 1989.

Appendices

Index

Appendix	Name of Appendix
1	Appendix 1 – Components of the TNUoS charge
2	Appendix 2 – The CUSC process and the CUSC panel vote
3	Appendix 3 – Methods of preventing smaller EG facing incentives not to generate at peak periods
4	Appendix 4 – The model, assumptions and results
5	Appendix 5 – Forecast non-locational embedded benefit calculations
6	Appendix 6 – Glossary
7	Appendix 7 – Ofgem Draft Impact Assessment Template

Appendix 1 – Components of the TNUoS charge

This appendix describes the Transmission Network Use of System (TNUoS) charging regime for demand. 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, which are explained in more detail below. The TNUoS demand charge is currently levied based on triad demand, which 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. Demand 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. The locational charges currently range from c.£-17 /kW to c. £8/kW, depending on location[110]. Embedded generation, when located in the right area, can help avoid incremental transmission investment costs, to the extent that they could help reduce flows on the transmission network.

Residual Charge

The locational component does not recover the full allowed revenue provided to the transmission owners through the RIIO 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. Networks often have high fixed costs, and relatively low proportions of costs that vary with use. Therefore, to ensure that the correct revenue is recovered, a non-locational 'residual' tariff element is included, the TNUoS Demand Residual. This is a cost recovery element which ensures that the total allowed revenue is recovered. The residual component of the charge is currently[111] £47.30/kW for all demand users, irrespective of their location in the country.

[110] 2017/18
[111] 2017/18

Treatment of smaller EG

Transmission-connected generation and embedded generation over 100MW on the distribution network pays TNUoS generation charges. 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 it was included as a continued locational signal for smaller EG in the WACMs presented to us (i.e. locational demand charging remain on net demand, and will not move to gross charging as the residual will). Smaller EG can 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.

Appendix 2 – 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:

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

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 our decision

We attend 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.

Options

The tables below show the WACMs that went to the Panel.

WACMs at-a-glance					
WACM Number:	**CMP264 Original**	**CMP265 Original**	**WACM 1**	**WACM 2**	**WACM 3**
New plant 'x'	£0	No change	Gen residual	Gen residual	**Avoided GSP**
Existing plant 'x'	No change				
Notes	Existing = Pre-07/17	No EB for CM plant	Immediate implementation	Phased in over 3 years	**Immediate implementation**
WACM Number	**WACM 4**	**WACM 5**	**WACM 6**	**WACM 7**	**WACM 8**
New plant 'x'	**Avoided GSP**	**Avoided GSP + Gen residual**	Lowest locational	**Lowest locational**	£32.30
Existing plant 'x'					
Notes	**Phased in over 3 years**	**Phased in over 3 years**	Immediate implementation	**Phased in over 3 years**	Immediate implementation
WACM Number	**WACM 9**	**WACM 10**	**WACM 11**	**WACM 12**	**WACM 13**
New plant 'x'	£34.11 (1Y), then £20.12	£45	Dem residual with offshore costs removed	Gen residual	**Avoided GSP**
Existing plant 'x'					
Notes	Immediate implementation	Immediate implementation	Offshore costs removed Immediate implementation	CM/CfD £45.33 until 2033	**CM/CfD £45.33 until 2033**
WACM Number	**WACM 14**	**WACM 15**	**WACM 16**	**WACM 17**	**WACM 18**
New plant 'x'	Avoided GSP + Gen residual	Lowest locational	£20.12	£32.30	Dem residual with offshore costs removed
Existing plant 'x'					
Notes	CM/CfD £45.33 until 2033	CM/CfD £45.33 until 2033	CM/CfD £45.33 until 2033	CM/CfD £45.33 until 2033	CM/CfD £45.33 until 2033 Immediate implementation
WACM Number	**WACM 19**	**WACM 20**	**WACM 21**	**WACM 22**	**WACM 23**
New plant 'x'	£0	£27.70 (5Y) then Gen residual	Lowest locational	£0	£34.11 (1Y) then £20.12
Existing plant 'x'	£45.33	£45.33 until 2033	£45.33 until 2033	£45.33 until 2033	£34.11 (10Y) then £20.12
Notes	Existing = Pre-07/17	Existing = Pre-11/18	Existing = Pre-11/18	Existing = Pre-07/19 and CM/CfD	Existing = Commissioned and 14/15 CM/CfD

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.

One of the CUSC Panel members abstained from voting throughout.

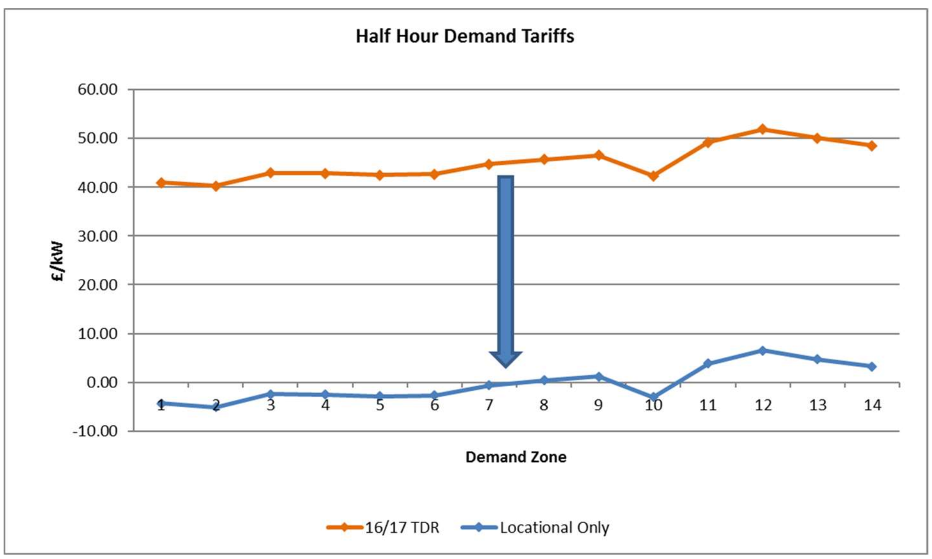
WACM Number	Better than the baseline	Best
264 Original	3	
WACM 1	8	
WACM 2	7	
WACM 3	8	4
WACM 4	7	
WACM 5	7	3
WACM 6	5	
WACM 7	5	1
WACM 8	1	
WACM 9	1	
WACM 10	1	
WACM 11	1	
WACM 12	1	
WACM 13	1	
WACM 14	1	
WACM 15	1	
WACM 16	1	
WACM 17	1	
WACM 18	1	
WACM 19	2	
WACM 20	0	
WACM 21	0	
WACM 22	1	
WACM 23	1	

WACM 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	0	

Appendix 3 – Methods of preventing smaller EG facing incentives not to generate at peak periods

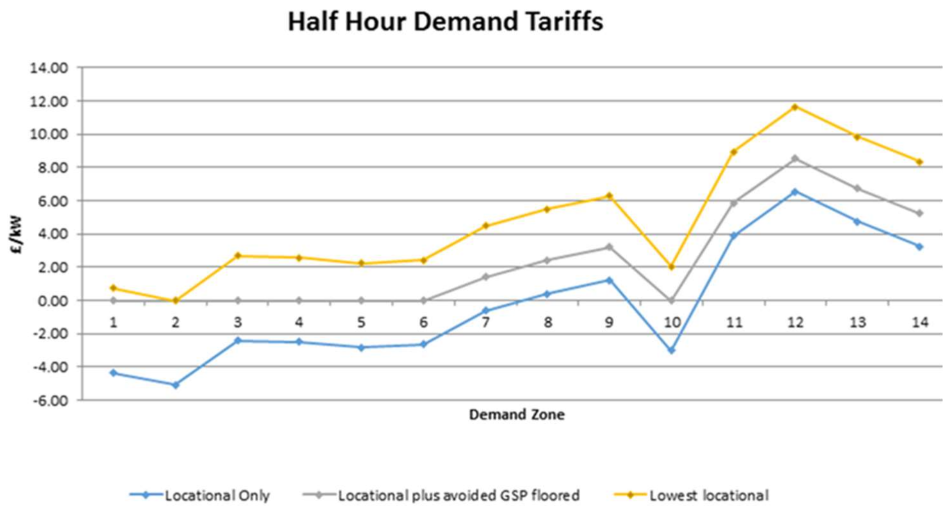
All of the WACMs have a value of 'x' which is added as an explicit payment. These range from zero to £45.33/kW. This value is in addition to the inverse of the demand value of the locational signal which smaller EG receive. The next few graphs illustrate some of these principles.

All smaller EG will receive the locational signal and then have an additional value of 'x' which will replace the TDR). The graph below shows the effect of removing the 2016/17 TDR of £45.33/kW[112] and exposing only the 2016/17 locational signal only.



Two options to 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 potential security of supply implications, and also revenue implications, as it was not clear how revenues could be recovered from non-CUSC signatories[113]. The effect of this is shown below, with a small number of zones seeing their charge amended to prevent them having to pay. This chart uses the 2016/17 tariffs.

[112] £47.30/kW 2017/18
[113] Many smaller EG are not CUSC signatories, though some 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 4 – 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".[114] 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, the estimate for reciprocating diesel capex is set at the CM minimum bid level of

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

£255/kW. Please see section 6 for details of sensitivities around BEIS Medium cost assumptions.

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 2021/22 and then flat thereafter.
- Losses and network build are not modelled.

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 "back casting" 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 Capacity	B - Existing capacity	C - Both
Scenario 1	System saving (£mn)	304.0	304.0	304.0	304.0
	Consumer saving (£mn)	1,621.0	1,621.0	1,621.0	1,621.0
Scenario 1 phased	System saving (£mn)	304.0	304.0	304.0	304.0
	Consumer saving (£mn)	1,617.0	1,618.0	1,620.0	1,621.0
Scenario 2	System saving (£mn)	1,379.0	1,379.0	1,379.0	1,379.0
	Consumer saving (£mn)	5,421.0	4,927.0	3,921.0	3,427.0
Scenario 2 phased	System saving (£mn)	1,375.0	1,375.0	1,375.0	1,375.0
	Consumer saving (£mn)	5,284.0	4,814.0	3,896.0	3,426.0
Generator Residual	System saving (£mn)	1,800.0	1,800.0	1,800.0	1,800.0
	Consumer saving (£mn)	6,531.0	5,755.0	4,171.0	3,395.0
Generator Residual phased	System saving (£mn)	1,762.0	1,762.0	1,762.0	1,762.0
	Consumer saving (£mn)	6,434.0	5,699.0	4,264.0	3,529.0
Scenario 3	System saving (£mn)	1,892.0	1,892.0	1,892.0	1,892.0
	Consumer saving (£mn)	7,740.0	6,883.0	5,136.0	4,279.0
Scenario 3 phased	System saving (£mn)	1,869.0	1,869.0	1,869.0	1,869.0
	Consumer saving (£mn)	7,542.0	6,725.0	5,129.0	4,312.0

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	Modelled directly - Generator residual, no phasing, no grandfathering	6531.0	1800.0
WACM 2	Modelled directly - Generator residual with phasing	6434.0	1762.0
WACM 3	Modelled directly - Scenario 3 (£1.62/kW), no grandfathering, no phasing.	7740.0	1892.0
WACM 4	Modelled directly - Scenario 3 (£1.62/kW) with phasing, no grandfathering.	7542.0	1869.0
WACM 10	Modelled directly, Scenario 1 (£45.33/kW), no grandfathering, no phasing	1621.0	304.0
WACM 12	Modelled directly - Generator residual with grandfathering, no phasing.	5755.0	1800.0
WACM 13	Modelled directly - Scenario 3 (£1.62/kW) with CM/CfD grandfathering, no phasing.	6883.0	1892.0
WACM 16	Modelled directly - Scenario 2 (£20.12/kW) with CM/CfD grandfathering, no phasing.	4927.0	1379.0

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 (£1.62/kW) with grandfathering for existing capacity and CM capacity, no phasing.	4279.0	1892.0
265 Original	Estimated from Scenario 3 (£45.33/kW) plus the difference between the CM grandfathering and the no grandfathering options (.) as these operators will not be paid.	2478.0	304.0
WACM 5	Estimated from Generator residual with phasing.	6434.0	1762.0
WACM 6	Estimated from Scenario 2 (£20.12/kW), no grandfathering, no phasing.	5421.0	1379.0
WACM 7	Estimated from Scenario 2 (£20.12/kW) with phasing, no grandfathering.	5284.0	1375.0
WACM 8	Estimated from a midpoint between Scenario 2 (£20.12/kW), no grandfathering, no phasing and Scenario 1 (£45.33/kW), no grandfathering, no phasing.	3521.0	841.5
WACM 9	Estimated from Scenario 2 (£20.12/kW), no grandfathering, no phasing	5421.0	1379.0

WACM 11	Estimated from Scenario 1 (£45.33/kW), no grandfathering, no phasing. While the payments are lower in early years, they rise to higher than this in later years	1621.0	304.0
WACM 14	Estimated from the Generator residual with CM grandfathering.	5755.0	1800.0
WACM 15	Estimated from Scenario 2 (£20.12/kW) with CM/CfD grandfathering, no phasing.	4927.0	1379.0
WACM 17	Estimated from a midpoint between Scenario 2 (£20.12/kW) with grandfathering, no phasing and Scenario 1 (£45.33/kW) with grandfathering, no phasing.	3274.0	841.5
WACM 18	Estimated from Scenario 1 (£45.33/kW) with CM/CfD grandfathering, no phasing. While the payments are lower in early years, they rise to higher than this in later years	1621.0	304.0
WACM 19	Estimated from Scenario 3 (£1.62/kW) with CM/CfD and existing grandfathering, no phasing.	4279.0	1892.0
WACM 20	Estimated from the Generator residual with full grandfathering. Will underestimate of the true consumer cost saving.	3395.0	1800.0
WACM 21	Estimated from Scenario 2 (£20.12/kW) with existing and CM/CfD grandfathering, no phasing. In practice the much later grandfathering cut-off date is likely to increase the cost of grandfathering	3427.0	1379.0
WACM 22	Estimated from Scenario 3 (£1.62/kW) with CM/CfD and existing grandfathering, no phasing. In practice the much later grandfathering cut-off date is likely to increase the cost of grandfathering	4279.0	1892.0
WACM 23	Estimated from Scenario 2 (£20.12/kW) with existing and CM/CfD grandfathering, no phasing, and Scenario 2 without grandfathering or phasing. In practice consumer savings may be lower if this payment level is above the "tipping point" at which further EG capacity is built.	4424.0	1379.0

*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.

Appendix 5 – Forecast non-locational embedded benefit calculations

The following analysis looks at the non-locational embedded benefits only. As previously stated we believe that the demand and generation locational signals are broadly comparable.

Forecasts of Non-locational Embedded Benefits

1. The level of embedded benefits received by a generator is dependent on a three key factors: the generator's technology type; their load factor; and their location.
    a. Technology type
        i. Plant are split between Intermittent and Conventional. Intermittent TNUoS plant do not pay the peak part of the TNUoS tariff.
    b. Load factor
        i. This has a large impact on the overall level of embedded benefit, with higher load factor plant avoiding more BSUoS payments, and being paid more BSUoS payments. For higher LF plant, this can form a fairly large BSUoS embedded benefits.
    c. Location
        i. This can, in certain areas, lead to a large impact on the benefit received because generation and demand zones are not directly comparable. They are however broadly similar in direction
2. In order to see if a plant receives a significant embedded benefit, these three variables must be known and the costs or benefits assessed for both transmission and embedded plant with the same characteristics.
3. In order to gain some general insight into the interactions of the BSUoS and TNUoS Non-locational Embedded Benefits we have undertaken some simple analysis[115] on the level of embedded benefit that would arise from particular generator types from the non-cost-reflective elements.
4. We have carried out this analysis using the following assumptions:
    a. *National Grid tariffs (updated Feb 2017) have been used.*
    b. *It is assumed that Ofgem implement WACM4 of CMP264/265, thus leading to a decrease in the level of TNUoS Demand Residual Embedded Benefit from £47.30/kW in 2017/18 to £0/kW in 20/21. The Avoided GSP cost has not been included, as if this is cost reflective, it is not an embedded benefit even if it does provide additional revenue to an embedded generator when compared with an equivalent transmission generator.*

c. *It is therefore assumed that embedded generators are not exposed to the generation residual.*
d. *BSUoS is modelled in three scenarios*
    i. *£2.54/MWh for all years from 2017/18 to 2020/21*
    ii. *£2.54/MWh in 2017/18 rising to £3.50/MWh in 2021/22 (in a straight line)*
    iii. *£2.54/MWh in 2017/18 rising to £5.00/MWh in 2021/22 (in a straight line)*

5. The following generators are modelled, each with the relevant load factors and peak output:
6. Generator characteristics:

Scenario	Type of generator	Output at peak	Annual Load Factor
Intermittent	Wind	5%	35%
Intermittent	Wind	20%	35%
Non int 90/05	Peaker	90%	5%
Non int 80/50	Conventional	80%	50%
Non int 90/80	Baseload	90%	80%

7. The below assumptions have been used for the analysis. The AGIC is not included as it is assumed to be a cost reflective charge:

TNUoS demand residual £/kW	2017/18	2018/19	2019/20	2020/21	2021/22
TNUoS demand residual (WACM4)	-47.30	-30.45	-15.23	0.00	0.00

TNUoS Generation residual £/kW	2017/18	2018/19	2019/20	2020/21	2021/2022
Generation residual	-1.85	-3.20	-4.54	-5.95	-7.61

BSUoS £/MWh	2017/18	2018/19	2019/20	2020/21	2021/2022
Flat 2.54	2.54	2.54	2.54	2.54	2.54
Rising to £3.50	2.54	2.78	3.02	3.34	3.50
Rising to £5.00	2.54	3.16	3.77	4.59	5.00

8. The following methodology was followed:

Element	**Treatment**
TNUoS demand residual (TDR)	The headline TDR figure for that year, unadjusted
Annual Load Factor	Used to calculate the hours for BSUoS benefits
Hours in year	There are 8760 hours in year. This is used to calculate BSUoS benefits.
Output at peak	This determine the revenue from the TDR

Generation residual (TGR)	This is levied on TG on TEC, so is not adjusted by ALF or Peak output. This is therefore removed from EG net revenue position as they are do not receive and TG do.
TDR residual benefit	This is inverse of TDR, adjusted for peak output
BSUoS (flat 2.54)	This is the headline BSUoS figure, adjusted by number of hours using ALF and hours. It is doubled, as EG do not pay, and are paid. This uses the current estimate of £2.54/MWh for all years.
BSUoS (Rising to £3.50)	As above, but with BSUoS rising from £2.54/MWh in 2017/18 to £3.50/MWh in 2020/21 (in a straight line)
BSUoS (Rising to £5.00)	As above, but with BSUoS rising from £2.54/MWh in 2017/18 to £5.00/MWh in 2020/21 (in a straight line)
Total (BSUoS 2.54 flat)	This is the total non-locational benefit for EG taking in TDR, TGR and BSUoS, with TDR adjusted by peak output and BSUoS adjusted by load factor. This uses the current estimate of £2.54/MWh for all years.
Total (BSUoS rising to £3.50)	As above, but the totals using BSUoS figures that rise to £3.50/MWh
Total (BSUoS rising to £5.00)	As above, but the totals using BSUoS figures that rise to £5.00/MWh

9. The results are as follows:

Intermittent - Wind 20% Peak output /35% Annual Load Factor

Our example assumes 35% load factor for BSUoS. Our analysis suggests that substantial non-location embedded benefit is likely to remain for wind generation, driven entirely by BSUoS. With 20% peak load factors, TDR revenue is lost due to the proposed phase out of TDR embedded benefit. Once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £9.63/kW and £22.20/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

Intermittent 20/35	2017/18	2018/19	2019/20	2020/21
TNUoS demand residual	-47.30	-30.45	-15.23	0.00
Annual Load Factor	0.35	0.35	0.35	0.35
Hours in year	8760	8760	8760	8760
Output at peak	0.20	0.20	0.20	0.20
Generation residual	-1.85	-3.20	-4.54	-5.95
TNUoS residual benefit	9.46	6.09	3.05	0.00
BSUoS (flat 2.54)	15.58	15.58	15.58	15.58
BSUoS (Rising to £3.50)	15.58	17.05	18.52	20.48
BSUoS (Rising to £5.00)	15.58	19.35	23.12	28.15
Total (BSUoS 2.54 flat)	*23.18*	*18.46*	*14.09*	*9.63*
Total (BSUoS rising to £3.50)	*23.18*	*19.93*	*17.03*	*14.53*
Total (BSUoS rising to £5.00)	*23.18*	*22.23*	*21.63*	*22.20*

Intermittent - Wind 5% Peak output /35% Annual Load Factor

Our example assumes 35% load factor for BSUoS. Our analysis suggests that substantial non-location embedded benefit is likely to remain for wind generation, driven entirely by BSUoS. Assuming lower 5% peak load factors and the proposed phase out of TDR embedded benefit, the already low TDR benefit is quickly entirely removed for these generators. Once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £9.63/kW and £22.20/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

Intermittent 05/35	**2017/18**	**2018/19**	**2019/20**	**2020/21**
TNUoS demand residual	-47.30	-30.45	-15.23	0.00
Annual Load Factor	0.35	0.35	0.35	0.35
Hours in year	8760	8760	8760	8760
Output at peak	0.05	0.05	0.05	0.05
Generation residual	-1.85	-3.20	-4.54	-5.95
TNUoS residual benefit	2.37	1.52	0.76	0.00
BSUoS (flat 2.54)	15.58	15.58	15.58	15.58
BSUoS (Rising to £3.50)	15.58	17.05	18.52	20.48
BSUoS (Rising to £5.00)	15.58	19.35	23.12	28.15
Total (BSUoS 2.54 flat)	*16.09*	*13.89*	*11.80*	*9.63*
Total (BSUoS rising to £3.50)	*16.09*	*15.37*	*14.74*	*14.53*
Total (BSUoS rising to £5.00)	*16.09*	*17.67*	*19.34*	*22.20*

Non-Intermittent - Baseload 90% Peak output /80% Annual Load Factor

This example assumes 80% load factor for BSUoS, reasonable for a CHP generator running baseload, such as a plant with a large heat load. Our analysis suggests that very large non-location embedded benefit is available for these operators, as high load factors bring high BSUoS benefits. Once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £29.65/kW and £58.38/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

Non int 90/80	**2017/18**	**2018/19**	**2019/20**	**2020/21**
TNUoS demand residual	-47.30	-30.45	-15.23	0.00
Annual Load Factor	0.80	0.80	0.80	0.80
Hours in year	8760	8760	8760	8760
Output at peak	0.90	0.90	0.90	0.90
Generation residual	-1.85	-3.20	-4.54	-5.95
TNUoS residual benefit	42.57	27.41	13.71	0.00
BSUoS (2.54 flat)	35.60	35.60	35.60	35.60
BSUoS (Rising to £3.50)	35.60	38.96	42.33	46.81
BSUoS (Rising to £5.00)	35.60	44.22	52.84	64.33
Total (BSUoS 2.54 flat)	*76.32*	*59.80*	*44.77*	*29.65*
Total (BSUoS rising to £3.50)	*76.32*	*63.17*	*51.50*	*40.86*
Total (BSUoS rising to £5.00)	*76.32*	*68.42*	*62.01*	*58.38*

Non-Intermittent - Conventional 80% Peak output /50% Annual Load Factor

This example assumes 50% load factor for BSUoS, which is reasonable for a small embedded non-CHP CCGT generator running some baseload operations. Our analysis suggests that substantial non-location embedded benefit is available for these operators, as higher load factors bring substantial BSUoS benefits. Due to the proposed phase out of TDR embedded benefit, the TDR benefit is entirely removed for these generators. However, once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £16.30/kW and £34.26/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

Non int 80/50	2017/18	2018/19	2019/20	2020/21
TNUoS demand residual	-47.30	-30.45	-15.23	0.00
Annual Load Factor	0.50	0.50	0.50	0.50
Hours in year	8760	8760	8760	8760
Output at peak	0.80	0.80	0.80	0.80
Generation residual	-1.85	-3.20	-4.54	-5.95
TNUoS residual benefit	37.84	24.36	12.18	0.00
BSUoS (2.54 flat)	22.25	22.25	22.25	22.25
BSUoS (Rising to £3.50)	22.25	24.35	26.46	29.26
BSUoS (Rising to £5.00)	22.25	27.64	33.03	40.21
Total (BSUoS 2.54 flat)	*58.24*	*43.41*	*29.90*	*16.30*
Total (BSUoS rising to £3.50)	*58.24*	*45.51*	*34.10*	*23.31*
Total (BSUoS rising to £5.00)	*58.24*	*48.79*	*40.67*	*34.26*

Non-Intermittent - Peaker 90% Peak output /5% Annual Load Factor

This example assumes 5% load factor for BSUoS. Our analysis suggests that substantial non-location embedded benefit is largely removed for peaking generation, as low load factors limit BSUoS benefits. Due to the proposed phase out of TDR embedded benefit, the TDR benefit is entirely removed for these generators, and they face competition from transmission connected generators that will receive the negative TGR payment on their whole TEC. Once the BSUoS embedded benefit is taken into account, the overall level of embedded benefit is between £-3.72/kW and £1.93/kW benefit in 2020/21 depending on the assumed level of BSUoS charges.

Non int 90/05	2017/18	2018/19	2019/20	2020/21
TNUoS demand residual	-47.30	-30.45	-15.23	0.00
Annual Load Factor	0.05	0.05	0.05	0.05
Hours in year	8760	8760	8760	8760
Output at peak	0.90	0.90	0.90	0.90
Generation residual	-1.85	-3.20	-4.54	-5.95
TNUoS residual benefit	42.57	27.41	13.71	0.00
BSUoS (2.54 flat)	2.23	2.23	2.23	2.23
BSUoS (Rising to £3.50)	2.23	2.44	2.65	2.93
BSUoS (Rising to £5.00)	2.23	2.76	3.30	4.02
Total (BSUoS 2.54 flat)	*42.94*	*26.43*	*11.40*	*-3.72*
Total (BSUoS rising to £3.50)	*42.94*	*26.64*	*11.82*	*-3.02*
Total (BSUoS rising to £5.00)	*42.94*	*26.97*	*12.47*	*-1.93*

We have looked into the annual load factors required for a peaker to receive enough BSUoS income to equal the TGR income that a TG generator could expect in 2020/21. Assuming BSUoS level of £2.54/MWh, a load factor of 13% is needed. However, if there are higher BSUoS values available at certain times of the year, the required load factors may be much lower.

Appendix 6 - 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 transmission and BSUoS related 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. 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.

SQSS

Security and Quality of Supply Standard (SQSS) sets out the criteria and methodologies for planning and operating the GB Transmission System.

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 have consulted on launching a targeted charging review (TCR) in May 2017.

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 7 – Ofgem Impact Assessment Template

Title: Impact Assessment and Decision on industry proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators	**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 ('smaller 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 smaller EG can receive. Suppliers pay smaller EG payments as it reduces their liability for the TDR charges, or National Grid pays smaller 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) Smaller 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 £69.59 /kW.

The lead policy removes net charging for all smaller 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). This level will be recalculated by National Grid prior to implementation using a methodology set out in the modification legal text.

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'.) Smaller 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 due to the change in technology that is used (more CCGT/OCGT, 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). The 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 to revise the levels should further analysis suggest that this is beneficial.

Key Assumptions/sensitivities/risks • Key capex assumptions for generation are based on BEIS figures for the relevant generation technologies. The base case model run uses the low values. The sensitivity of results to higher costs has been explored. • 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. • The impact of capacity market drop out has been assessed. • The potential impact on industry hurdle rates has been considered but these are not thought to be sufficiently evidenced

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