



Review of Ofgem's Open Letter on Charging Arrangements for Embedded Generation

Prepared for the Association for Decentralised Energy

23 September 2016

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Executive Summary

Our Assignment

NERA Economic Consulting (NERA) has been commissioned by the Association for Decentralised Energy (ADE) to review an Open Letter published by Ofgem published on 23 July 2016 on charging arrangements for embedded generation.¹

Ofgem's letter seeks views on the case for potential reforms of network charging arrangements for embedded generators, in particular in response to its "concerns that the charging arrangements for embedded generators... may over-reward embedded generation, which could be having an increasing impact on the energy system, by potentially distorting investment decisions and leading to inefficient outcomes in the CM".² Responses to the letter will also inform the decision Ofgem will need to make in respect of some specific proposed modifications to the current Transmission Network Use of System (TNUoS) charging methodology set out in the Connection and Use of System Code (CUSC). These modification proposals are known as CMP264 (proposed by Scottish Power) and CMP265 (proposed by EDF), and a number of variants on them have also been proposed through an ongoing industry working group process.

While Ofgem's Open Letter discussed a range of different areas of network charging policy, its main concern appears to be potential problems with current TNUoS arrangements, through which the Transmission Owners (TOs) recover transmission infrastructure costs. Therefore, this report focuses on reviewing the case for reform of TNUoS charges, including the specific reforms currently proposed to the CUSC, which purport to address some of the concerns Ofgem's Open Letter raises.

There are Serious Logical Flaws with Ofgem's Critique of the Current TNUoS Arrangements and the Suggested Reforms

Ofgem's recent Open Letter on embedded benefits sets out its apparent belief that the current methodology for setting the TNUoS charges faced by smaller embedded generators is not cost-reflective, and is distorting competition between smaller and larger generators. The root of Ofgem's concern seems to be the demand residual component of the charges, which it characterises as not cost-reflective and designed to recover "fixed/sunk" costs. By contrast, it characterises the locational elements of the wider TNUoS charges as being broadly cost-reflective, albeit recognising some areas for possible improvements in the economic signals they send.

There are a number of problems with Ofgem's critique of the current methodology, and the potential case for reform set out in its Open Letter. In particular, the decomposition of the D-TNUoS charge into a supposedly cost-reflective locational component and a residual that only exists to recover "fixed/sunk" costs is entirely artificial:

¹ Ofgem (23 July 2016), *Open letter: Charging arrangements for embedded generation*. Henceforth, "Ofgem Open Letter".

² Ofgem Open Letter, page 1.

- The locational element of D-TNUoS charges is only “cost-reflective” in the sense that it emerges from a load flow modelling exercise that seeks to estimate the degree to which costs *vary* by location. Hence, the locational charge seeks to reflect only the degree of variation in charges across the country.
- The *level* of the locational charge – and by implication the level of the demand residual charge – is in no sense cost-reflective. In fact, it depends on regulatory decisions on the G:D split (currently determined by EU regulations) that have not been justified with reference to cost reflectivity, and on the choice of the reference node within the load flow model.

Ofgem is therefore wrong to characterise the locational element of the D-TNUoS charge as cost-reflective, and to characterise the residual component as not cost-reflective. As such, the logical foundation for Ofgem’s critique of the current TNUoS methodology and the reforms it appears to be contemplating are extremely weak.

Rather than Problems with the Residual Component, Growth in the Residual Charge Results in Part from Wider Flaws in the Design of the Locational Charge

Rather than there being a problem with the residual charge itself, any problems with the current methodology probably arise mainly from problems with the locational element of the charge. For instance, the D-TNUoS locational charge does not account for differences in the transmission costs that users impose on the system in off-peak conditions, which is an increasingly important driver of transmission investment.

As evidence of this problem with the locational charge, we observe that it recovers only a very small proportion of total transmission costs, leaving a large amount of revenue to be recovered through the residual. This suggests that the locational element of the charge does not target the full costs of providing transmission capacity on the parties that drive transmission costs. Modelling by Imperial College also suggests that if the locational element of the charge was set closer to LRMC, the amount of revenue the locational charge recovers could increase materially. Therefore, flaws with the locational element of the charge mean that Ofgem’s concerns about the rising level of the residual could be addressed more effectively through reform of the locational element of the charge.

Moreover, as we discuss in this report, while Ofgem seems to be concerned with potential distortions to competition between large and small generators, the modifications it is currently considering introduce new distortions to competition. In particular, the current approach to net D-TNUoS charging ensures a common treatment for net demand reduction, however it is achieved (eg. demand response, embedded generation, etc.). As we discuss below, by introducing gross charging for embedded generation, the modifications Ofgem is considering would create a range of new distortions to competition between alternative means of reducing net demand.

The CUSC Modifications Proposed to Date, in Particular the Introduction of Gross Charging, Introduce New Distortions to Competition, which Undermines the Case for Immediate Reform

The Ofgem Open Letter also invites industry participants’ views on the remedies that have been put forward to the supposed distortion that Ofgem identifies (CUSC modifications

CMP264 and CMP265) as well as variants that we understand have been put forward through an ongoing working group process.

All of these modifications introduce “gross charging”, which means embedded generators’ output would cease to be netted off from demand for the purpose of computing suppliers’ D-TNUoS charges. Instead, embedded generators’ TNUoS costs would be calculated separately (ie. on a gross basis), and we understand that many of these modifications involve materially reducing the extent to which embedded generators receive the negative demand residual as a component of their TNUoS charge (or revenue).

The economic basis for these changes is extremely weak, because it relies on Ofgem’s assertion that it is possible to decompose the current charge into some components that are cost-reflective and others that are not. Decomposing the charge in this way is not meaningful, for the reasons described above. As such, the proposed gross charging methodologies that effectively remove the demand residual from embedded generators’ TNUoS charges are also unjustified on grounds of cost-reflectivity.

Even if it were meaningful to decompose charges in this way, we have identified a series of potential flaws with these proposed modifications to the charging methodology:

- A number of the proposed modifications introduce elements of “gross charging”, which means charging arrangements will differ for embedded generators and consumers who may have generation capacity “behind the meter”, and for providers of demand side response. Embedded generation, generation located behind the meter and demand response all impose the same cost on the transmission system, which should be reflected in the charges. The proposed change towards gross charging of embedded generators could materially distort competition between distributed energy resources, creating a new source of inefficiency. Neither Ofgem nor the working group have sought to evaluate the effect of such distortions arising from the introduction of a new source of undue discrimination into the charging methodology.
- We understand that some modifications, including CMP264, introduce differential treatment for new and existing embedded generators, which will further distort competition between these categories of plant, resulting in potentially inefficient closure/investment decisions. This approach also introduces undue discrimination, because whether a generator connects to the system before or after some arbitrary date does not affect the costs they impose on the transmission grid.
- Some modifications, including CMP265, introduce differential treatment for embedded plants, depending on whether they have obtained a Capacity Market contract. This approach will distort existing generators’ incentives to bid into the Capacity Market auctions, as they will need to factor in the cost of losing D-TNUoS revenues when setting their bids. This approach also introduces undue discrimination, as possession of a Capacity Market contract would not influence the costs they impose on the transmission system.
- CMP265 and some other alternative proposals we understand have been put forward also exempt some embedded generators from receiving the residual component of the D-TNUoS charge. Aside from being unjustified on grounds of cost-reflectivity as we discuss above, this approach would result in some generators facing negative D-TNUoS. Because of the link between D-TNUoS and triad production, this change would provide a

material disincentive for some embedded generators to produce during peak periods, which could cause extremely high peak wholesale energy prices, and possibly even hamper security of supply, if the disincentive (per MWh) is close to the effective price cap in the balancing mechanism.

- Those modifications which artificially compress locational signals, such as by setting locational charges to zero in cases when the load flow modelling suggests they should be negative, create a new distortion through the removal or dilution of locational signals. Variation in locational charges across the country is intended to send efficient locational signals to network users. Removing this charge could cause material inefficiency in the locational decisions of new plants, or the closure incentives for existing plant.

As set out above, many of the proposed revisions to the TNUoS methodology put forward through the CMP264/5 working group process would introduce significant new distortions to competition. Ultimately, such distortions will introduce new sources of inefficiency which act against the customer interest.

Further Work Would Be Needed to Assess the Relative Harm Caused by these New Distortions, Relative to any Benefit from Removing Existing Purported Distortions

Ofgem may consider that there are trade-offs between existing distortions in the current methodology that the proposed modifications claim to address and any new distortions they introduce. As we describe above, this would be an unsound position to adopt, because the logical basis for the purported distortion in the current methodology is extremely weak. However, at the least, we would expect Ofgem to make some effort to estimate the welfare costs associated with the new distortions it would create by accepting the modifications put forward through the working group process, and to trade these off against the welfare improvements it believes the modifications deliver. To date, as far as we are aware, the CMP264/5 working group has not made any assessment of the likely welfare effects of new distortions.

The Rationale for a Stop Gap Measure is Extremely Weak

A further problem with the proposed modifications is that they all represent “stop gap” measures that either implement reforms that lapse when Ofgem implements a more fundamental review of TNUoS pricing, or are in effect stop-gap measures because they fail to comprehensively address the current shortcomings of the D-TNUoS methodology.

In addition to the weaknesses in the logical foundation for the (presumably temporary) changes to TNUoS put forward so far, there is also little rationale for any reform pending more fundamental review by Ofgem.

Specifically, Ofgem’s main concern appears to be the distortion to competition between investments in large transmission-connected plant and smaller embedded plant, which affects (amongst other things) the Capacity Market price. Apart from the fact that this distortion is unproven, addressing this concern does not require a change in TNUoS charges today, particularly when the modifications proposed introduce so many new distortions. It would be sufficient for Ofgem to signal its intent to reform TNUoS charges along certain lines in order to guide investors in new embedded plant as to the basis on which they should factor in the D-TNUoS revenue stream into their investment decisions and/or Capacity Market bid prices.

Also, any more fundamental review of TNUoS charges could be in place before the start date of the Capacity Market contracts currently being procured through four year-ahead auctions.

Modelling the LRMC of Transmission Shows Wider Problems with the Locational Element of D-TNUoS Charges; Growth in the Residual is a Symptom of these Problems

As we also discuss in this report, there are a number of problems with the locational element of the current D-TNUoS charge that may be limiting the amount of revenue it recovers from network users. As such, to address any potential problems associated with expected growth in the demand residual charge, it may produce more efficient outcomes and improve cost-reflectivity to modify the locational rather than the residual element of the charge.

To test this hypothesis, we have used Imperial College's DTIM model to estimate the amount of revenue that would be recovered through locational TNUoS charges linked to the Long-Run Marginal Cost (LRMC).

Through this modelling exercise, we have estimated the revenue that would be recovered through the locational element of the charge, if it were set to better reflect the LRMC of transmission. The results demonstrate that this improvement could materially increase the amount of revenue collected through locational charges from around 10% to around 60% of the total revenue recovered through "wider" TNUoS charges, and thus reduce the amount that needs to be collected through the residual. Following the discussion above, this modelling therefore provides further evidence that there is a need for some reform of the locational element of the charge, before any reform of the residual.

Overall Conclusion

The logical basis for the changes in the TNUoS methodology that Ofgem's Open Letter seems to be contemplating is extremely weak. In particular, the notion that the D-TNUoS charge can be split into the locational element of the charge that is cost-reflective, and the residual charge that represents a charge to recover the "fixed/sunk" costs of the network is entirely unjustified. The locational element of the charge is only designed to signal differences in the cost that demand imposes across different locations, not the absolute level of transmission cost that demand imposes. The ratio between the two depends on regulatory decisions regarding what share of costs generation and demand should bear, and the arbitrary choice of reference node in the charging methodology.

If fact, rather than a problem with the residual charge, there are a range of flaws associated with the locational element of the charge. If these flaws were rectified, the locational element of the charge would recover a larger amount of revenue, and the expected growth in the demand residual could be moderated.

In fact, the range of reforms to TNUoS arrangements put forward through the CMP264/5 working group process also introduce a range of new distortions that would detrimentally affect welfare. Any new reform aimed at addressing existing distortions would need to examine carefully the trade-off between the new distortions that the modifications would create.

1. Introduction

NERA Economic Consulting (NERA) has been commissioned by the Association for Decentralised Energy (ADE) to review an Open Letter published by Ofgem on 23 July 2016 on charging arrangements for embedded generation.³

Ofgem's letter seeks views on the case for potential reforms of network charging arrangements for embedded generators, in particular in response to its "concerns that the charging arrangements for embedded generators... may over-reward embedded generation, which could be having an increasing impact on the energy system, by potentially distorting investment decisions and leading to inefficient outcomes in the CM".⁴ Responses to the letter will also inform the decision Ofgem will need to make in respect of some specific proposed modifications to the current Transmission Network Use of System (TNUoS) charging methodology set out in the Connection and Use of System Code (CUSC).

Hence, Ofgem's main concern appears to be potential distortions to current TNUoS arrangements, through which the TOs recover transmission infrastructure costs. Therefore, this report focuses on reviewing the case for reform of TNUoS charges, including those specific reforms currently proposed to the CUSC that purport to address some of the concerns Ofgem's Open Letter raises.

Our review of the Ofgem Open Letter, as set out in the remainder of this report, is structured as follows:

- To provide the factual basis for the analysis that follows in subsequent chapters, Chapter 2 describes the current methodology for setting TNUoS charges for both generation and demand;
- Chapter 3 then describes the key concerns with the current TNUoS methodology set out in the Ofgem Open Letter, and summarises the key features of the reforms that have been proposed in two CUSC modifications (CMP264 and CMP265) that are currently going through a CUSC working group process;
- Chapter 4 evaluates the case for reform set out in the Ofgem Open Letter, and assesses the extent to which the proposed modifications are likely to improve the overall cost-reflectivity of the TNUoS methodology and the economic efficiency of market outcomes;
- Chapter 5 summarises the findings of quantitative modelling conducted by Imperial College London, which estimates the cost of transmission investment associated with changes in net demand in different parts of the transmission system; and
- Chapter 6 concludes on the case for change set out in Ofgem's Open Letter, on the case for implementing the proposed modifications currently being considered by the CUSC

³ Ofgem (23 July 2016), *Open letter: Charging arrangements for embedded generation*. Henceforth, "Ofgem Open Letter". Note, "Embedded generation" refers to generation that is connected to distribution systems rather than being connected to the transmission system.

⁴ Ofgem Open Letter, page 1.

working group examining CMP264 and CMP265, and on the need for wider reform of the TNUoS methodology to address the problems Ofgem identifies.

2. Overview of the TNUoS Methodology

2.1. Categories of Transmission System Costs

The costs of electricity transmission fall into the following two broad categories:

1. *Infrastructure capacity and operating costs:* To move power from one location to another, transmission infrastructure is required. The costs of building and maintaining the required transmission assets depend on their capacity to transport electricity from one area to another and on the distance over which this capacity is provided, regardless of any flow of energy over those assets.
2. *Short-run system operating costs:* Once energy starts to flow over the transmission assets, it imposes additional costs of two kinds.
 - A. *Constraint costs:* When insufficient transport capacity is available to accommodate power flows, instead of transporting power from one area to another, expensive generators that would not be dispatched in an uncongested system have to be dispatched to ensure supply exactly equals demand in all parts of the system, giving rise to constraint costs.
 - B. *Losses:* the further energy travels along a transmission line, the higher the proportion of the energy that is lost. These losses have to be replaced, at a cost, by increasing total generation output accordingly.

In Great Britain, the Transmission Owners (TOs) recover infrastructure capacity and operating costs through Transmission Network Use of System (TNUoS) charges. The costs of constraints (inter alia) are recovered through Balancing Service Use of System (BSUoS) charges. The costs of transmission losses are allocated to producers and consumers by applying Transmission Loss Multipliers (TLMs) that marginally reduce the volume production with which generators are credited in settlement, and marginally increase the amount energy suppliers have to purchase.

As set out in the previous chapter, Ofgem's main concern appears to be potential distortions to current TNUoS arrangements. Therefore, the remainder of this chapter describes the current arrangements for setting TNUoS charges, which provides background for the review of Ofgem's Open Letter that follows in the subsequent chapters.

2.2. The Role of TNUoS Charges

2.2.1. Arrangements for the recovery of transmission infrastructure costs

A key role of TNUoS charges is to allow the TOs to recover the costs of providing and maintaining transmission infrastructure.⁵ The total revenue to be raised through TNUoS charges is defined by the TOs' Maximum Allowed Revenue (MAR), which is determined to a large extent by Ofgem's decision regarding the level of revenue that regulated transmission

⁵ TNUoS charges are also the channel through which other transmission infrastructure owners recover their costs, notably the Offshore Transmission Owners (OFTOs).

companies are allowed to recover through their revenue controls. National Grid forecasts that MAR will increase from £2.7 billion per annum in 2016/17 to £3.8 billion by 2020/21. Over £600 million (or 55%) of this expected increase is due to the development of new offshore transmission networks.⁶

2.2.2. Sending cost-reflective signals through TNUoS charges

As well as recovering total transmission costs, as defined by MAR, the TNUoS methodology also seeks to signal to network users the transmission investment costs they impose on the system, and how these costs vary at different locations on the network. This approach aims to encourage generators and consumers to make an efficient trade-off between the costs they impose on the system and other costs and revenue streams.⁷

The detailed charging methodology, through which the TNUoS charges faced by individual generators or consumers are calculated, is set out in Section 14 of the CUSC.⁸ This methodology is based on the so-called Investment Cost Related Pricing (ICRP) approach, which aims to set tariffs according to the transmission investment costs that different network users impose on the system. In this sense, the TNUoS methodology aims to be cost-reflective, and send economic signals to network users regarding the costs that their presence imposes on the transmission system. For instance, the CUSC states that:⁹

“The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems.”

Both the calculations used to set TNUoS charges and the philosophy behind the ICRP methodology are linked to the planning standard that defines the transmission investments that the TOs are obliged to make to accommodate different types of users in different locations. This standard is known as the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS).¹⁰

Among other things, the SQSS defines how much transmission has to be built to accommodate changes in the mix of generation technologies, the volume or location of

⁶ National Grid (11 February 2016), *Forecast TNUoS tariffs from 2017-18 to 2020-21*, page 4.

⁷ For instance, when selecting a new site for a wind farm, generation developers may face a trade-off between the relatively high transmission costs they face in more remote parts of the country, as compared to the benefits of higher load factors available in these areas. On the demand side, there are similar trade-offs between the costs of accessing the transmission system and the costs of other factors or production such as labour and land that also vary across the country.

⁸ The CUSC constitutes the contractual framework for connection to, and use of, National Grid's high voltage transmission system.

⁹ National Grid (1 April 2016), *The Connection and Use of System Code (CUSC) v1.12*, section 14, part 2, para. 14.14.6.

¹⁰ The NETS SQSS defines a coordinated set of criteria and methodologies that transmission licensees must follow in the planning and operation of the NETS of Great Britain.

generation capacity, and changes in the level or regional dispersion of peak demand. It does this by requiring that the TOs build sufficient capacity to meet two planning criteria, which, taken together, define the level of demand and the mix of generation that the transmission system must be built to accommodate:

- *The Security Criterion* defines the need for transmission to meet peak demand when output from intermittent generation (eg. wind or solar) is assumed to be zero; and
- *The Economy Criterion* defines the need for transmission to accommodate transmission flows that meet peak demand in a scenario when the output from intermittent generation is relatively high. This criterion is intended to define the amount of transmission investment required to make an efficient trade-off between the costs of transmission investment and the costs of congestion management.

As we discuss further below, these criteria also form the basis for the calculation of TNUoS charges under the current methodology. As such, the TNUoS methodology attempts to send cost-reflective signals regarding the transmission costs that users impose on the system, by linking the charges they face to the transmission investment costs the TOs are required (by the SQSS) to make to accommodate them.

2.3. Splitting Transmission Costs Between Demand and Generation

One of the first steps required to set TNUoS charges is to determine the amount of revenue that has to be recovered through tariffs levied on demand and generation. The current methodology sets the share of MAR recovered from generators equal to 27% of the total,¹¹ but subject to an additional constraint. Specifically, European Union (EU) rules cap the amount of transmission infrastructure cost that can be recovered from generators to an average charge of €2.50/MWh of generation output.¹²

At present, this cap limits the share of MAR that can be recovered from generators to only 23% of the total MAR at present. This share is expected to fall in the coming years, primarily because the charges associated with the cost of offshore transmission assets will rise substantially (as noted above). As these charges will contribute to the €2.50/MWh limit being binding, the proportion of total MAR that can be recovered from generators is forecast to fall below 20% by 2019/20.¹³

As we describe further below, the next step in implementing the TNUoS methodology is to calculate the charges that are levied on users in different parts of the system. Specifically, generators' TNUoS charges depend on where in the country they are located, whether they connect to the transmission or distribution system, their size, their historic production and

¹¹ National Grid (1 April 2016), *The Connection and Use of System Code (CUSC) v1.12*, section 14, part 2, para. 14.14.5.

¹² European Commission Regulation 838/2010 Part B, para. 3.

¹³ National Grid (2 February 2015), *Forecast TNUoS tariffs from 2016-17 to 2019-20 Tables*, Table 20 – Calculation of Residuals.

their technology. Consumers' TNUoS charges depend on their location and their consumption during the peak “triad” periods.¹⁴

2.4. The Structure of Generation TNUoS Charges

2.4.1. The components of G-TNUoS charges

G-TNUoS charges are paid by transmission-connected generators¹⁵ and by large embedded generators with capacity above 100MW.¹⁶ These charges are paid per kW of Transmission Entry Capacity (TEC).¹⁷

G-TNUoS charges are comprised of Local and Wider Tariffs. Both have several components:

- The Local Tariff is to reflect the cost of the local network.¹⁸ It contains two elements, which vary according to the point at which generators connect to the grid:
 - The Local Substation element; and
 - The Local Circuit element.¹⁹
- The Wider Tariff is to reflect the cost of the wider national network. It contains four elements:
 - Three elements that vary by location on the network, as defined by 27 charging zones:
 - A Peak Security element;²⁰
 - A Year Round Non-Shared element; and

¹⁴ “Triad” is used as a short hand way to describe the three Settlement Periods of highest transmission system demand, namely the half hour Settlement Period of system peak Demand and the two half hour Settlement Periods of next highest Demand, which are separated from the system peak Demand and from each other by at least 10 Clear Days, between November and February inclusive. See National Grid (22 March 2016), *The Connection and Use of System Code (CUSC)* v1.69, section 11.3.

¹⁵ Transmission connected generators are those with a Bilateral Connection Agreement (BC) connected at 275kW or above in England and Wales or 132kV and above in Scotland. See National Grid (December 2015), *Introduction to Charging: Which Parties Pay Which Charges*, note to Table 1.

¹⁶ National Grid (December 2015), *Introduction to Charging: Which Parties Pay Which Charges?*, note to Table 1.

¹⁷ “The Transmission Entry Capacity of a generator is the commercial capacity of that generator required to give it access to the transmission system and to allow it to participate in the wholesale market. TEC is used as the chargeable capacity of a generator for TNUoS charging purposes.” See National Grid (20 December 2013), *Review of the Embedded (Distributed) Generation Benefit arising from transmission charges*, Glossary.

¹⁸ National Grid (1 April 2016), *The Connection and Use of System Code (CUSC)* v1.12, section 14, part 2, para. 14.15.2.

¹⁹ In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system. Main Interconnected Transmission System (MITS) nodes are defined as: Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or connections with more than 4 transmission circuits connecting at the site. Generators directly connected to a MITS node will have a zero local circuit tariff. Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets). See National Grid (1 April 2016), *The Connection and Use of System Code (CUSC)* v1.12, section 14, part 2, para. 14.15.32, 14.15.33, 14.15.35 and 14.15.36.

²⁰ The Peak Security element of the Wider Tariff is not levied on intermittent generators.

- A Year Round Shared element; and
- A “Residual” element, which does not vary by location.

This report focuses on the “wider” elements of TNUoS charges, which are structured as set out in Table 1. As the table shows, wider G-TNUoS charges depend on the zone in which the generator connects to the grid, as well as its technology and historic Average Load Factor (ALF).

Table 1
Calculation of the “Wider” Elements of TNUoS Charges Paid by Generators

Component of Charge	Intermittent Generators	Other Generators
Peak Security Charge	Exempt	£/kW Zonal Charge x TEC
Year Round Charge (Shared)	£/kW Zonal Charge x TEC x ALF	£/kW Zonal Charge x TEC x ALF
Year Round Charge (Non-shared)	£/kW Zonal Charge x TEC	£/kW Zonal Charge x TEC
Residual	£/kW Charge x TEC	£/kW Charge x TEC

Source: NERA review of charging arrangements set out in the CUSC

2.4.2. Derivation of the “wider” components of G-TNUoS charges

The calculation of G-TNUoS charges uses a modelling tool to estimate the incremental transmission cost of adding generation capacity to the system at different geographical points in a way that implements the ICRP methodology set out in the CUSC.²¹

The modelling procedure estimates the change in power flows around the transmission system resulting from marginal changes in injections to the system at different transmission nodes. This tool is known as the “DCLF ICRP Transport Model”:

- The modelling procedure computes the change in transmission flows on every circuit (measured in MWkm) that is caused by marginally changing (by 1MW) injections at each node, with an offsetting change at a “reference node”.
- By multiplying the change in transmission flows by an “expansion constant”, which represents the marginal cost of adding transmission capacity, the procedure estimates the change in transmission costs associated with marginally changing injections at each node.

The TNUoS methodology entails running this modelling procedure with the level of demand and the generation mix defined as per the “Security” and “Economy” criteria in the SQSS

²¹ National Grid (December 2015), *Introduction to final generator payments*.

(see Section 2.2.2 above).²² From these runs of the model, the various components of wider G-TNUoS charges described in Table 1 are derived.

The first step in this process is to allocate all transmission circuits between the peak security and year-round charges.²³

- If a circuit has higher transmission flows in the run of the modelling implementing the “Security” criterion, then it is allocated to the peak security charge. The link between the “Security” criterion and the peak security charge reflects the intention that this component of the charge signals the transmission costs that generators impose on the system in peak demand, low wind conditions.
- If a circuit has higher transmission flows in the run of the modelling implementing the “Economy” criterion, then it is allocated to the year-round charge. The link between the “Economy” criterion and the year-round charge reflects the intention that this component of the charge signals the transmission costs incurred in order to balance transmission investment and constrain costs efficiently.

The modelling procedure then computes the change in transmission flows that result from marginal changes in injections in different parts of the system, and uses the result to estimate the incremental cost of changes in transmission flows:²⁴

- The locational peak security charge for a particular zone is derived by estimating the change in transmission flows (on those circuits allocated to this charge) that result from marginally changing injections in that zone in the “Security” criterion run of the model.²⁵ These changes in flows are then multiplied by the “expansion constant” to estimate the incremental cost of changes in transmission flows.
 - Generators’ liability to pay the peak security charge is linked to their TEC, as Table 1 explains.
- The calculation of the year-round charge is similar. It is derived by estimating the change in transmission flows (on the circuits allocated to the year-round charge) that result from marginally changing injections in that zone in the “Economy” criterion run of the model. These changes in flows are also multiplied by the “expansion constant” to estimate the incremental cost of changes in transmission flows.
 - The year round charge is then broken into the “shared” and “non-shared” elements, which aim to reflect the fact that less transmission investment may be required to accommodate generation in parts of the system with a broad mix of technologies that will tend not to run at the same time (i.e. the methodology tries to reflect the fact that they can “share” transmission assets to some degree).

²² National Grid (1 April 2016), *The Connection and Use of System Code (CUSC) v1.12*, section 14, part 2, para. 14.14.9.

²³ National Grid (1 April 2016), *The Connection and Use of System Code (CUSC) v1.12*, section 14, part 2, para. 4.15.26.

²⁴ National Grid (1 April 2016), *The Connection and Use of System Code (CUSC) v1.12*, section 14, part 2, paragraphs 14.15.26, 14.15.27 and 14.15.28.

²⁵ In practice, this calculation is performed on a node-by-node basis, the results of which are then averaged to set the zonal charge.

- Generators’ liability to pay the “shared” component of the year-round charge is linked to their ALF and their TEC; the “non-shared” element is only linked to generators’ TEC, as Table 1 explains.

The total revenue collected through these locational charges might not be sufficient to recover the total share of MAR that needs to be recovered through G-TNUoS charges, or may recover too much revenue. Hence, the “residual charge” is calibrated to ensure total G-TNUoS revenue recovers the appropriate share of MAR (discussed above in Section 2.3). The generation residual charge is levied on generators per kW of TEC and does not vary across the transmission system.²⁶

2.4.3. Wider G-TNUoS Charges resulting from this methodology

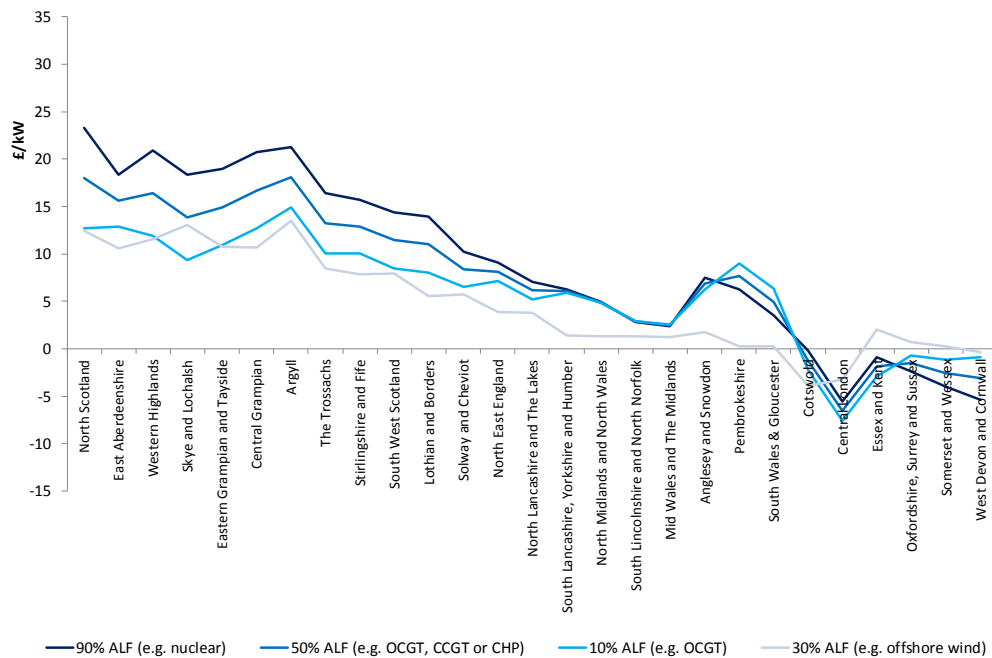
Figure 1 shows wider G-TNUoS charges across the 27 generation zones in 2016/17, and Figure 2 shows National Grid’s latest forecast for 2019/20.²⁷ The figures also show how the charges vary by generators’ ALF. Charges are lower in absolute terms for generation technologies with relatively low load factors because the (shared) year-round charge is linked to ALF. The figures also show the effect of intermittent generators’ exemption from paying the peak security charge.

For all technologies, the wider TNUoS charges are relatively low or even negative in some zones towards the south of the system (on the right-hand-side of the figures). This reflects the fact that increasing generation towards the south reduces the need for power to flow through the transmission system from northern generators to meet southern demand. By contrast, charges tend to be higher towards the north of the country (on the left-hand-side of the figures), reflecting the relative surplus of generation in this part of the system.

²⁶ National Grid (1 April 2016), *The Connection and Use of System Code (CUSC) v1.12*, section 14, part 2, para. 14.15.132.

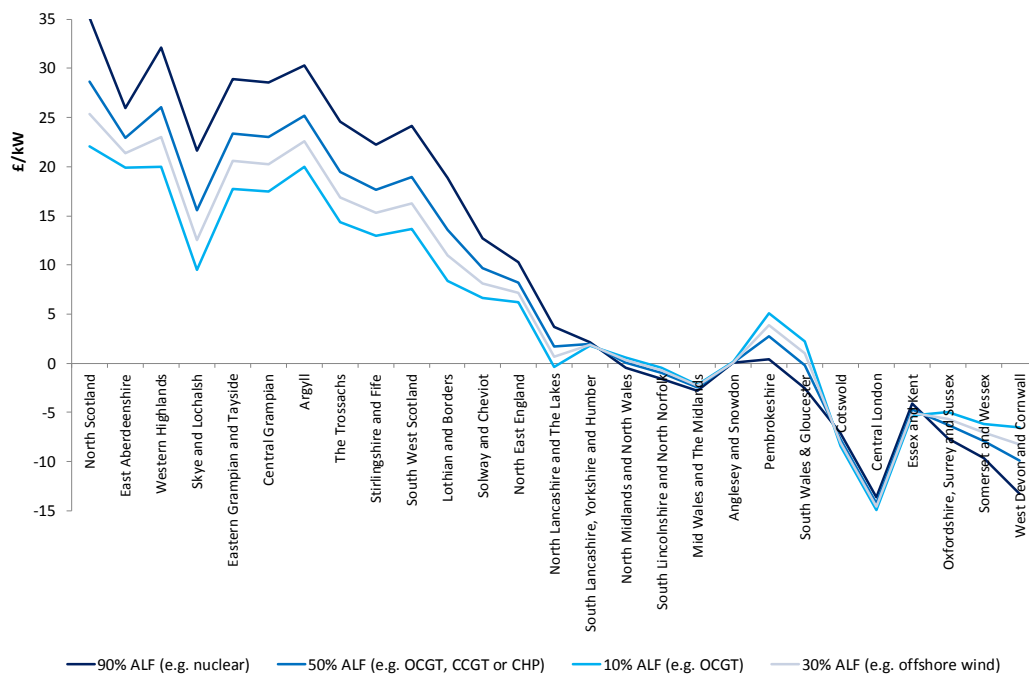
²⁷ Note: The assumed ALFs in the figures are 90% for baseload generators, 50% for mid-merit generators, 10% for peakers and 30% for intermittent generation.

Figure 1
Wider G-TNUoS Charges by Generation Zone and Annual Load Factor 2016/17 (£/kW)



Source: National Grid.²⁸

Figure 2
Wider G-TNUoS Charges by Generation Zone and Annual Load Factor 2019/20 (£/kW)



Source: National Grid.²⁹

²⁸ National Grid (2 February 2015), *Forecast TNUoS tariffs from 2016-17 to 2019-20 Tables*.

2.5. The Structure of Demand TNUoS Charges

2.5.1. D-TNUoS charges are structured to reflect the impact of growth in peak demand on transmission costs

The D-TNUoS charges (for customers' with half-hourly meters) are levied based on customers' average net demand (kW) over the 'Triad' periods each year. Customers who are not metered half-hourly are charged according to the sum of their annual consumption (in kWh) between 4pm and 7pm.

As for G-TNUoS charges, D-TNUoS charges comprise local and wider tariffs with components similar to those described in Section 2.4.1, but here we focus on the wider elements of the charge which are considered by the Ofgem Open Letter.

As Table 2 sets out, there are some similarities between the wider G-TNUoS and the D-TNUoS charging methodologies. In particular, the D-TNUoS methodology also contains locational charges based on the "Security" and "Economy" criteria in the SQSS. They are based on estimates of the transmission costs incurred to accommodate marginal changes in demand in each part of the system under these backgrounds using the DCLF model.

D-TNUoS charges also contain a non-locational residual charge, set to recover the share of MAR allocated to D-TNUoS charges (see Section 2.3 above).

Table 2
Components of D-TNUoS Charges

Component of Charge	Computation for Charge Half Hourly Metered Customers
Peak Security Demand Charge	£/kW Zonal Charge x Triad Consumption
Year Round Demand Charge	£/kW Zonal Charge x Triad Consumption
Demand Residual	£/kW Charge x Triad Consumption

Source: NERA review of charging arrangements set out in the CUSC

2.5.2. Differences in the calculation of locational components of the D-TNUoS and G-TNUoS charges

Despite several similarities, there are some differences between the locational charges levied on consumers through D-TNUoS charges and the locational charges levied on generators through the G-TNUoS charges:

²⁹ National Grid (2 February 2015), *Forecast TNUoS tariffs from 2016-17 to 2019-20 Tables*.

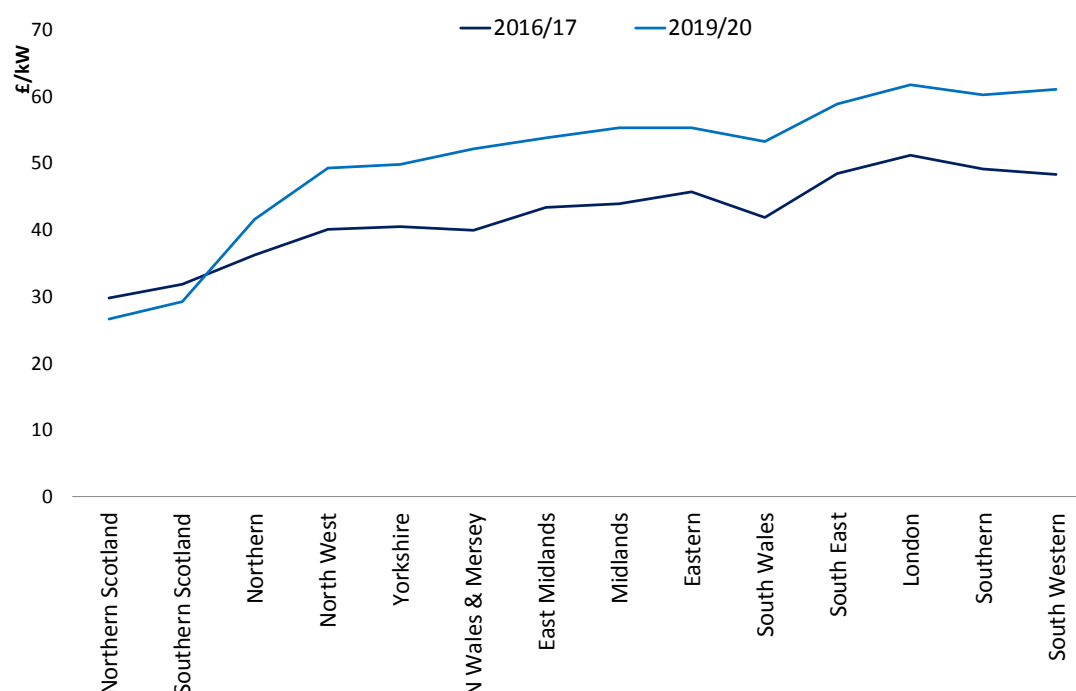
- Consumers' liability to pay the year-round D-TNUoS charge does not depend on their load factor (ie. there is no scaling by ALF as there is in the G-TNUoS charge). The D-TNUoS methodology also has no adjustment for the degree of "sharing" of transmission assets in the year-round charge. In the G-TNUoS methodology, these adjustments seek to reflect differences in the transmission costs caused by different network users, depending on their behaviour at times other than peak (the ALF adjustment) and how the transmission costs they impose vary depending on the types of network users with which they are deemed to share transmission assets; and
- The D-TNUoS methodology sets charges for each of the 14 Grid Supply Point (GSP) zones. By contrast, G-TNUoS charges are set for zones defined by groups of transmission nodes where the marginal cost of accommodating changes in generation is similar.

In addition to these differences in the locational elements of the charge, while generators are charged on the basis of their TEC, half-hourly metered consumers are charged according to the average net demand (kW) they take over the 'triad' periods. Also, unlike the G-TNUoS methodology, D-TNUoS charges have a floor of £0/kW.

2.5.3. Wider D-TNUoS Charges resulting from this methodology

Figure 3 shows National Grid's latest forecasts of the wider D-TNUoS charges by GSP zone. For 2016/17, demand charges are forecast to range from £29.79/ kW in the North to £51.25/kW in the South. By 2019/2020, National Grid forecasts that D-TNUoS tariffs will range from £26.65/kW in the North to £61.83/kW in the South.

Figure 3
Wider D-TNUoS Charges (Half-Hourly Metered Customers) by Demand Zone (£/kW)



Source: NERA analysis of National Grid³⁰ data

2.6. Charges for Smaller Embedded Generation

Embedded generators with a capacity below 100MW do not pay G-TNUoS charges. Instead, their output during triad periods can be used (in settlement) to offset suppliers' demand from half-hourly metered customers that defines their obligation to pay D-TNUoS charges. In effect, therefore, embedded generators receive a payment defined by the negative of the D-TNUoS charge applicable to their location on the grid. This revenue stream is linked to their production during the triad period.

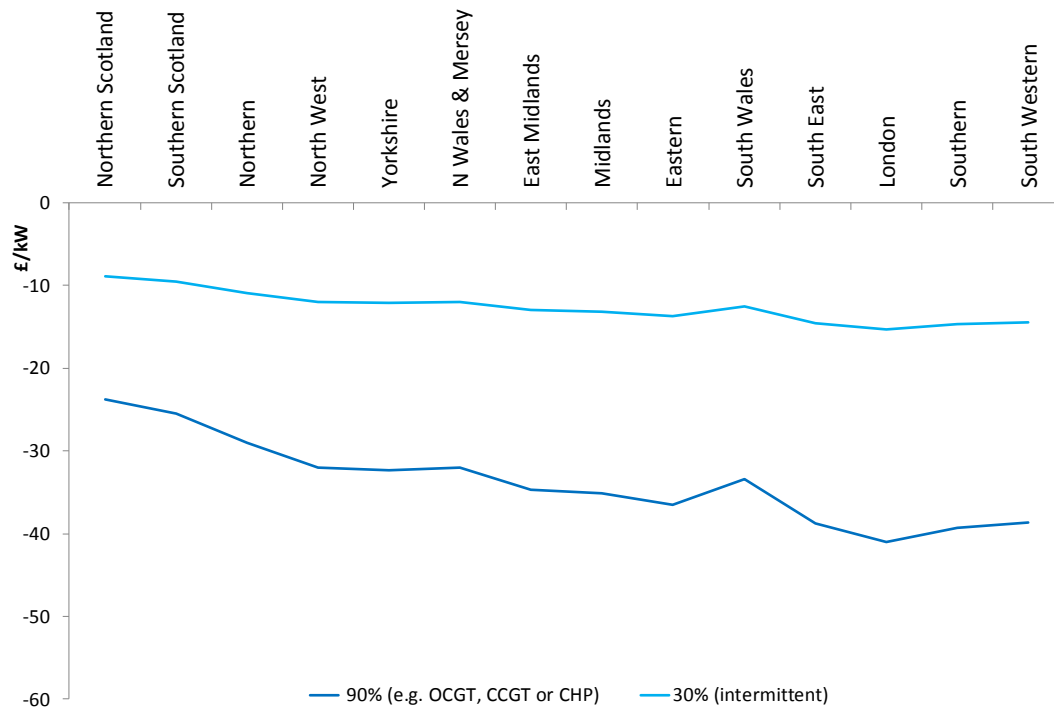
The logic behind this approach to charging is that, if the D-TNUoS tariff is reflective of the costs imposed on the network by more demand, then embedded generators should receive the negative of this D-TNUoS charge to reflect the benefit they offer to the transmission system through reducing demand.

Based on the same projections of D-TNUoS shown in Figure 3 for 2016/17 and 2019/20, Figure 4 and Figure 5 show the negative D-TNUoS charges that generators would face, depending on their assumed production during triad. Specifically, for this illustration we assume thermal plants (eg. CHP and OCGT) would generate at 90% of their capacity during the triad period, and intermittent generators (eg. wind) would generate at 30% of capacity during the triad.

³⁰ National Grid (2 February 2015), *Forecast TNUoS tariffs from 2016-17 to 2019-20 Tables*.

The figures show that, as for G-TNUoS charges, there is some locational variation in charges, with embedded generators in the South facing lower (ie. more negative) TNUoS charges per kW than embedded generators in the North.

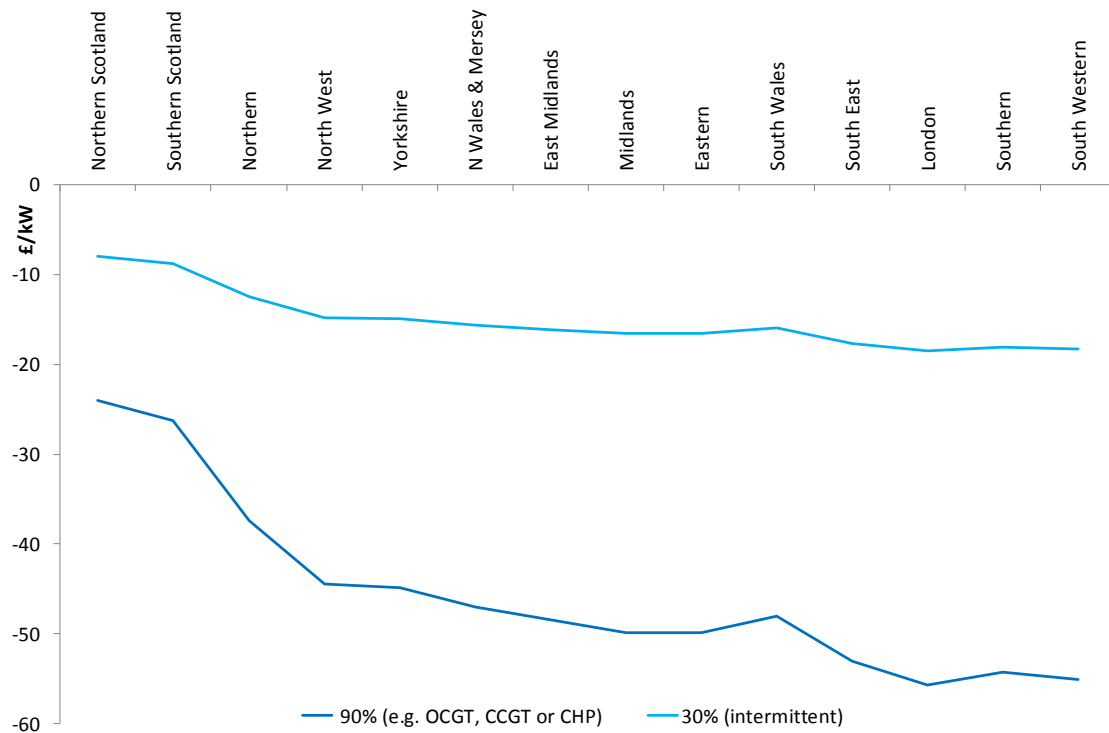
Figure 4
Negative Wider D-TNUoS Charges by Demand Zone and Technology 2016/17 (£/kW)



Source: NERA analysis of National Grid³¹ data

³¹ National Grid (2 February 2015), *Forecast TNUoS tariffs from 2016-17 to 2019-20 Tables*.

Figure 5
Negative Wider D-TNUoS Charges by Demand Zone and Technology 2019/20 (£/kW)



Source: NERA analysis of National Grid³² data.

³² National Grid (2 February 2015), *Forecast TNUoS tariffs from 2016-17 to 2019-20 Tables*.

3. The Purported Distortion and Proposed Remedies

3.1. Purported Distortions in the Current TNUoS Methodology

3.1.1. Purported distortion related to the current method for calculating the D-TNUoS residual charge

As explained above, embedded generators allow suppliers to reduce the load to be served at peak times, and as such allow them to reduce their liability to pay D-TNUoS charges that are linked to net consumption during the peak “triad periods”. If the D-TNUoS tariff is reflective of the costs demand consumers impose on the transmission system, this arrangement ought to produce efficient outcomes. Specifically, it should allow embedded generators to receive the benefit they provide to the transmission system through the avoidance of transmission costs via demand reduction.

However, in its Open Letter, Ofgem asserts that this logic does not hold. The following quotation summarises the core of the problem Ofgem sees within the current methodology:³³

“[Embedded generation] can receive payments for helping suppliers reduce their demand transmission charges including reducing their contributions towards fixed/sunk cost recovery. The connection of an increasing amount of sub-100MW [embedded generation] to the distribution system logically cannot help to avoid sunk/fixed costs of developing and maintaining the transmission network. The payments to EG are an extra cost to suppliers over and above the payment of transmission charges to National Grid, and therefore an additional cost to consumers, to the extent that this cost is passed on to consumers.”

Ofgem seems mainly to be concerned about purported distortions resulting from the residual element of the D-TNUoS charge, and thinks there is a case for a change to the method for computing and allocating the residual:³⁴

“We are particularly concerned about TNUoS demand residual payments which account for the majority of the embedded benefit and are forecast to increase significantly. We think that this element currently may be leading to the biggest distortions and that therefore there may be grounds to make changes to the charging arrangements in this area as a priority. We think that changes to how TNUoS demand residual charges are allocated among suppliers would create a more level playing field between sub-100MW EG and other generation.”

Ofgem suggests that, as a result of these problems, the current TNUoS methodology distorts market outcomes in several ways.³⁵ It considers the current charging method could lead to an inefficient mix of generation by encouraging investment in smaller distribution connected generation over larger transmission connected generators or embedded generators over

³³ Ofgem Open Letter, page 4.

³⁴ Ofgem Open Letter, page 4.

³⁵ Ofgem Open Letter, page 5.

100MW. Ofgem also suggests that larger or transmission connected generators may close earlier than they would in the absence of this purported distortion in the charging methodology, as they struggle to compete with smaller embedded generators. For instance, Ofgem raises the concern that increases in the demand residual payments may be:³⁶

“leading to an inefficient mix of generation by encouraging investment in smaller distribution connected generation (which can take advantage of the embedded benefits revenue stream) over potentially more efficient larger transmission connected generators (TG) or over-100MW EG (which do not have that revenue stream)”.

As a symptom of these effects, to the extent that embedded generators set or influence prices in the Capacity Market, Ofgem argues that clearing prices may be lower than they would be in the absence of the purported distortion. Ofgem raises concerns that the high demand residual payments may be “distorting the outcome of the capacity market (CM) by holding down prices since smaller EG can bid in at significantly lower prices than larger EG and TG”.³⁷ Moreover, innovation would be distorted “towards parties who can best capture this large payment”.³⁸

3.1.2. Other possible distortions that Ofgem identifies related to the current D-TNUoS methodology

Ofgem notes another possible distortion, which results both from its concerns regarding the link between embedded generators’ TNUoS costs and their production during the triad periods. Ofgem states that the process for setting embedded generators’ D-TNUoS costs “dampen[s] prices at peak times when EG dispatch out of merit to generate in the triad periods”.³⁹

Ofgem also identifies a distortion that results from differences in the locational signals sent to network users through the demand and generation locational charges, but leaves this to be discussed in the future.^{40 41}

3.2. Proposed CUSC Modifications Aiming to Alter D-TNUoS

Two industry participants, Scottish Power and EDF, have proposed modifications to the CUSC that they believe address to some extent the purported distortions described in Ofgem’s Open Letter. A working group process is currently considering these proposed

³⁶ Ofgem Open Letter, page 5.

³⁷ Ofgem Open Letter, page 5.

³⁸ Ofgem Open Letter, page 5.

³⁹ Ofgem Open Letter, page 5.

⁴⁰ Ofgem Open Letter, page 6.

⁴¹ Ofgem considers the demand and generation locational charges to be “roughly equivalent” and therefore only has minor concerns regarding distortions resulting from this part of the tariff. However, the differences between the two signals (the TNUoS demand locational signal and the TNUoS generation locational signal) are: (1) the difference in charging bases, triad vs TEC, (2) different treatment of intermittent/non-intermittent, and (3) different zonal differentiation (27 generation zones vs 14 GSP Groups). See Ofgem Open Letter, page 3, Table 1.

modifications, and through this process working group members have been putting forward a range of alternative proposals. We describe the two initial CUSC modification proposals (CMP264 from Scottish Power and CMP265 from EDF) below.

3.2.1. CMP264 sets D-TNUoS revenue to zero for new embedded generators connecting after 2017

Scottish Power submitted CMP264 to the CUSC Modifications Panel for its consideration in May 2016. It argues that due to the increasing volume of embedded generation output and the growth in MAR, the value of the negative D-TNUoS charges received by embedded generators is increasing. Scottish Power suggests that this increasing value of triad avoidance is not cost-reflective in terms of the transmission reinforcement avoided by reducing peak demand.⁴²

CMP264 proposes to stop deducting the output of new embedded generators (defined as those connecting after June 2017) from suppliers' consumption volumes for the purposes of calculating their liability to pay D-TNUoS. That is, it aims to stop new embedded generators from receiving any revenue through negative D-TNUoS charges, setting both the locational and residual elements of the charge to zero for these parties.⁴³

This proposal is intended as a 'stop-gap' solution until Ofgem confirms that it has completed its consideration of the issues (and any review which may ensue) and any resulting changes have been fully implemented.

3.2.2. CMP265 sets the demand residual to zero for any embedded generator with a Capacity Market contract

EDF submitted CMP265 to the CUSC Modifications Panel in May 2016. In an attempt to address the distortion identified in Ofgem's Open Letter on Capacity Market outcomes, CMP265 sets the residual element of the D-TNUoS charge to zero for all embedded generators with a Capacity Market contract.

Hence, in contrast to CMP264, EDF suggests removing only the demand residual payments, not the locational element, and only from the embedded generators with Capacity Market contracts. In contrast to CMP264 which is intended as a temporary measure, EDF suggests CMP265 could be a long-term solution, unless superseded by an implemented outcome of either Ofgem or National Grid following a wider review of charging arrangements that has effect in the same area of the CUSC. However, given Ofgem's Open Letter suggests it is likely to consider longer-term reforms of TNUoS arrangements, this modification also appears (in effect) to be a stop-gap measure.

⁴² National Grid (2 August 2016), Stage 02: Working Group Consultations *CMP264: Embedded Generation Triad Avoidance Standstill and CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market*. Table 1: Comparison of the Original CMP264 and CMP265 proposals.

⁴³ National Grid (2 August 2016), Stage 02: Working Group Consultations *CMP264: Embedded Generation Triad Avoidance Standstill and CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market*. Table 1: Comparison of the Original CMP264 and CMP265 proposals.

3.3. Conclusions

As set out above, Ofgem's main concern seems to be the residual element of the D-TNUoS charge. This position seems to be based on Ofgem's characterisation of the locational element as a "cost-reflective" charge and the residual as a charge to ensure recovery of "fixed/sunk" costs, which the current methodology allows embedded generators to avoid. As this chapter describes, an industry working group is considering two CUSC modifications that the proposers believe address this purported distortion.

The distinction Ofgem makes between the cost-reflective locational element of the charge and the residual that it alleges is not cost reflective is, on the face of it, intuitively appealing. As we explain in the previous chapter, the locational element of the charge emerges from a load flow modelling exercise that seeks to estimate the change in transmission investment costs associated with changes in demand in different parts of the system. Thus, the residual simply shifts these charges up or down to achieve total revenue equal to the share of MAR to be recovered from generation or demand.

However, as we discuss further in the next chapter, this simple characterisation of the two components of the charge is misleading, despite its intuitive appeal. It is wrong simply to describe the locational element as cost reflective, and the residual as being a transfer to recover sunk costs. Any conclusions that Ofgem draws from this simplistic interpretation of locational and residual components of the charge is therefore flawed.

The next chapter also discusses a range of other problems with the proposed modifications currently under consideration by the industry working group.⁴⁴

⁴⁴ The CMP264/5 working group documents make the same mistake of characterising the locational component of TNUoS charges as being reflective of the marginal cost that the additional capacity imposes on the transmission system, and the residual as being related to cost recovery or akin to some form of taxation mechanism. The working group consultation document states that "*The demand residual is [therefore] a non-locational, non-cost reflective balancing item and may be considered equivalent to a form of taxation with the purpose of raising revenue from demand for sunken costs. In this sense, it is not cost reflective although the money raised is used to fund various costs associated with building, maintaining and running the transmission network such as depreciation, return, direct and indirect operating costs or non-avoided costs.*"

See National Grid (2 August 2016), Stage 02: Working Group Consultations *CMP264: Embedded Generation Triad Avoidance Standstill* and *CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market*, para. 3.2.18.

4. Problems with the Proposed Remedies

4.1. The Flawed Characterisation of the Residual Charge

4.1.1. The role of the reference node in setting TNUoS charges

As explained above, the G-TNUoS and D-TNUoS charges consist of locational components and a residual component. The locational components are all computed by estimating the change in transmission costs resulting from marginally increasing power injections at each node of the system (reflecting a marginal increase in generation) and removing this same amount of power from a “reference node” (reflecting the marginal increase in demand):

- Within the generation and demand backgrounds used in National Grid’s load flow model, the prevailing flow of power tends to be from north to south. Hence, increasing generation or reducing demand at nodes to the north of the reference node tends to increase the (modelled) need for transmission to accommodate these north-south flows and hence increases the costs imposed on the system. As such, the locational element of the charge to the north of the reference node tends to be positive for generators and negative for demand.
- The locational charge in zones close to the reference node tends to be close to zero: increasing generation/demand at a node close to the reference node and then making an offsetting reduction in generation/demand at the reference node does not materially affect transmission flows.
- Increasing generation or reducing demand at nodes to the south of the reference node tends to reduce prevailing north to south transmission flows. This reduces the (modelled) need for transmission to accommodate these power flows and hence decreases the costs imposed on the system. As such, the locational element of the charge to the south of the reference node tends to be negative for generators and positive for demand.

Once the locational elements have been computed, the next step in setting both D-TNUoS and G-TNUoS charges is to set the non-locational residual charges such that total revenues recovered precisely match the shares of MAR allocated to demand and generation. As described in Section 2.3 above, the shares are constrained by an EU rule requiring that generators pay no more than €2.50/MWh on average in transmission infrastructure charges.

4.1.2. Illustrating the effect of changing the reference node

Importantly, the choice of reference node under the current methodology, which could in principle be placed anywhere in the system, does not influence the level of D-TNUoS charges (locational plus residual) that consumers face or embedded generators receive as a revenue stream under the current methodology.⁴⁵ This effect is illustrated by the three graphs in Figure 6, which show the effect of placing the reference node at different locations in the system. However, as Figure 6 also shows, while the total D-TNUoS charges are not affected

⁴⁵ The total level of D-TNUoS charges is determined by the level of revenue that must be recovered through D-TNUoS charges, which is essentially total MAR less the share of MAR allocated to generation which is currently constrained to be no higher than €2.50/MWh multiplied by total generation.

by the location of the reference node, the breakdown of the charge between the locational and residual elements *does* depend on the choice of reference node:

- The left graph in Figure 6 shows the current total wider D-TNUoS charges (locational plus residual charge in 2016/17). It also plots the locational element of the charge across the 14 demand zones, and notes that the difference between these two lines is the residual charge. Under the current method for setting the reference node, the locational element of the charge is roughly zero in the Midlands, negative to the north and positive to the south. The non-locational residual charge of £43.61 per kW increases the D-TNUoS charge in all zones such that total D-TNUoS charges range between around £30 per kW in the north to almost £50 per kW in the south west.
- In a transmission system in which the prevailing power flow tends to be from north to south, as is the case at present, placing the reference node in the far north of the system would increase the overall revenue raised by the locational element of the D-TNUoS charge. In all locations to the south of the new reference node, the locational element of the D-TNUoS charge would tend to be positive and higher than at present. As a result, the residual charge would need to decrease to ensure the total share of MAR not paid by generators is recovered. The overall D-TNUoS charge would be the same, because the locational variation in charges would still be determined by the same load flow modelling procedure, and the total amount of revenue recovered through D-TNUoS charges would still be the same.
 - The middle graph in Figure 6 illustrates the impact of moving the location of the reference node to the North of Scotland: a shift of the reference node to the North of Scotland would not change total D-TNUoS charges. They would still be around £30 per kW in Northern Scotland and close to £50 per kW in the South West. However, the composition of the charges would change. The locational charge in Northern Scotland would now be close to zero and positive in the remainder of the country. The demand residual would be lower, only around £30 per kW.
- In a transmission system in which the prevailing power flow tends to be from North to South, as is the case at present, placing the reference node in the south of the system would decrease the locational element of the D-TNUoS charge. In all locations to the north of the new reference node, the locational element of the D-TNUoS charge would tend to be negative and hence lower than at present. As a result, the residual charge would need to increase to ensure the total share of MAR not paid by generators is recovered. The overall D-TNUoS charge would be the same, because the locational variation in charges would still be determined by the same load flow modelling procedure, and the total amount of revenue recovered through D-TNUoS charges would be the same.
 - The right graph in Figure 6 illustrates the impact of moving the location of the reference node to the far south of the system. This would reduce the locational element of the D-TNUoS charge throughout the country. The locational element of the charge would be close to zero in the South, where it is currently positive. Then, in all locations north of this point, the locational element of the D-TNUoS charge would tend to be low or negative. As a result, the residual charge would need to be higher to ensure the total share of MAR not paid by generators is recovered. However, the total D-TNUoS charges would be the same, because the locational variation in charges would still be determined by the same load flow modelling procedure, and the total

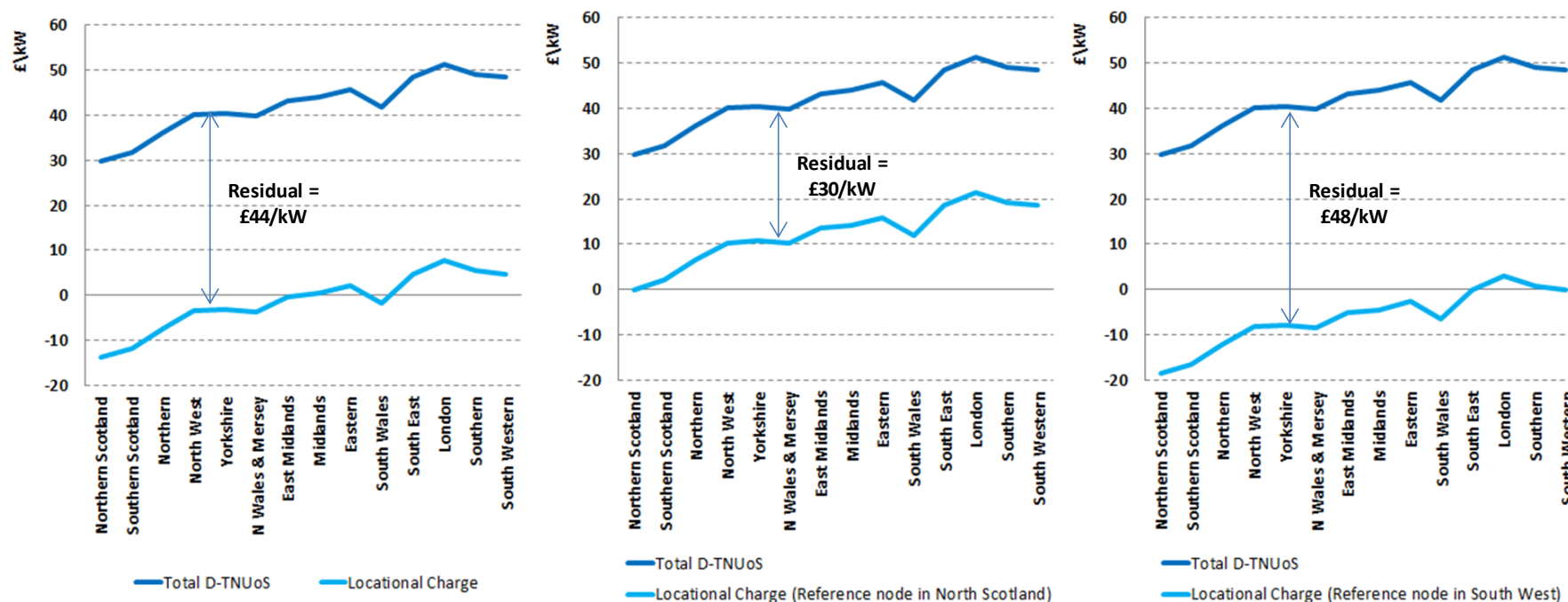
amount of revenue recovered through D-TNUoS would still be the same. The residual would now be around £48 per kW.

As a further illustration of the role of the reference node, consider the current approach used within the TNUoS methodology of using a “distributed reference node”, which distributes the reference node around the system in proportion to the location of demand. Taking this approach to set the reference node, consider the slightly extreme case of where all electricity demand is located at a single node (A), and this node is connected to a second node at which all generation is connected to the system (B).

In this case, marginal increases in peak demand would marginally increase the need for transmission to move power from B to A, and the installation of embedded generation to serve peak demand locally at node A would reduce the need for transmission. However, in this case, the ICRP methodology would set a locational charge for demand at node A equal to zero, because node A would be the reference node and locational charges are zero at the reference node. As such, embedded generation would receive no signal regarding the value they bring to the system in terms of peak demand reduction if they only face the locational element of the charge.

This example and the graphical analysis demonstrate that the locational charge alone does not send cost-reflective signals to network users. Rather, it is intended to signal the variation in costs imposed on the grid by users in different locations, ie. the relative costs of transmission in different locations, not the level of costs.

Figure 6
Total and Locational D-TNUoS Charges by Demand Zone 2016/17 (£/kW):
Actual Charges (left), and Illustrative Effects of Shifting the Reference Node to North Scotland (middle) and the South West (right)



Source: Actual tariffs from National Grid.⁴⁶ We calculate the illustrative change in the locational elements of the charge by preserving the same regional variation in tariffs as in the current D-TNUoS and the same total D-TNUoS charges in each zone, as these would not change if the reference node were altered. We then assume that the locational charge would be exactly zero in the new reference node.

⁴⁶ National Grid (2 February 2015), Forecast TNUoS tariffs from 2016-17 to 2019-20 Tables.

4.1.3. Implications for the proposed reform of D-TNUoS charges

The discussion above illustrates that the ratio between the residual and locational elements of the charge is determined to a large extent by the choice of reference node, and by the total share of transmission revenue that is allocated to demand and generation.⁴⁷ These are parameters set as part of the charging methodology. They are determined through largely arbitrary decisions⁴⁸ that are not part of any assessment of the proportion of transmission revenue required to cover (in Ofgem’s words) the “sunk/fixed costs of developing and maintaining the transmission network”.

It is therefore incorrect to characterise the level of the locational element of the D-TNUoS charge as being cost-reflective and the other element (the residual) as not cost-reflective. In fact, the locational charge, as its name suggests, seeks to send cost-reflective signals regarding how the cost users impose on the transmission system varies across one dimension only, namely across different *locations*. It does this through the degree of variation in charges across the country. By contrast, the *level* of the locational component of the charge is determined by the choice of reference node. And under the current methodology this choice of reference node does not matter, because it does not affect total D-TNUoS charges. As such the choice of reference node and the resulting level of locational charges is essentially arbitrary.

The key implication of this discussion is that the logical foundation for the distortion Ofgem discusses is unsound, because the level of residual and locational charge is arbitrary and bears no relation to the proportions of costs that are “fixed/sunk” and attributable to particular users.⁴⁹ And by the same logic, Ofgem’s apparent suggestion that the distortion can be addressed through an adjustment of the residual charge,⁵⁰ as CMP265 and a range of other variant proposals also suggest, would represent an equally arbitrary change to the current D-TNUoS charging methodology.

⁴⁷ For instance, changes in the amount of revenue allocated to demand and generation would shift the residual (and hence total D-TNUoS in all zones) up or down in all three of the illustrations shown in Figure 6.

⁴⁸ As discussed above, the choice of the (distributed) reference node is an arbitrary decision under the current D-TNUoS methodology, because it does not influence the overall D-TNUoS charges users face. Also, the proportion of MAR allocated to generation and demand is defined by the EU limiting average G-TNUoS to €2.50/MWh, which is not linked to any analysis of the costs of the transmission network.

⁴⁹ The CMP264/5 working group documents also characterise the locational component of the TNUoS charges as being reflective of the marginal cost that the additional capacity imposes on the transmission system, and the residual as being related to cost recovery or akin to some form of taxation mechanism. That is, the residual is to ensure that the allowed revenue (MAR) is recovered. For instance, the working group consultation asserts that: “The demand residual is [therefore] a non-locational, non-cost reflective balancing item and may be considered equivalent to a form of taxation with the purpose of raising revenue from demand for sunken costs. In this sense, it is not cost reflective although the money raised is used to fund various costs associated with building, maintaining and running the transmission network such as depreciation, return, direct and indirect operating costs or non-avoided costs.”

Source: National Grid (2016), Stage 02: *Working Group Consultations CMP264: Embedded Generation Triad Avoidance Standstill and CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market*. Paragraph 3.2.18.

⁵⁰ Ofgem Open Letter, page 4, 5.

4.2. Related Problems with Existing Locational Signals

As we discuss above, the residual charge is used to adjust the TNUoS charges so that wider TNUoS charges (locational plus residual charge) recover the total revenue requirement, with the desired proportions allocated to generation and demand. As such, if there are distortions created by the residual element of the charge, they could result – at least in part – from problems with the design of the locational element of the charge.

In fact, there are a number of possible problems with the locational signals currently conveyed through the TNUoS regime, as we discuss below.

4.2.1. There are a number of limitations in the current methodology for setting locational charges

The current method for setting the locational element of TNUoS charges fails to recognise that two (otherwise identical) generators impose the same cost on the transmission system, irrespective of whether they are embedded within distribution systems or connected to the transmission system. There should also be no difference between the transmission costs imposed on the system (per kW of generation capacity) by embedded generators with capacities above or below 100MW, if they are designed and operated in an identical way in other respects. The current approach of setting different charges for different types of generation depending on whether they are embedded or not and depending on size does not reflect the fact that they impose the same costs on the transmission system.

Another difference between the G-TNUoS and D-TNUoS charging methodologies is that the current D-TNUoS regime fails to account for the different costs that users impose on the system depending on differences in the profile of their consumption/production. The D-TNUoS charge faced by consumers depends on their behaviour during the peak triad periods, but it does not reflect the costs they impose (or help the transmission system to avoid) at other times. In the same way, the locational D-TNUoS charges faced by embedded generators also fail to recognise the impact of their behaviour on transmission system costs.

To explain this discrepancy between the D-TNUoS and G-TNUoS locational charges, consider the following example:

- The economic case for reducing transmission congestion on the England-Scotland border has been used to justify investments in significant reinforcement projects, notably the HVDC bootstrap.
- A key driver of both the congestion on this border and the need reinforcement is the expected growth in wind generation in Scotland. In essence, more transmission capacity is needed to export power from Scotland on windy days, and avoid curtailing generation in Scotland due to transmission congestion.
- Higher demand in Scotland on windy days could help to reduce constraints, in effect absorbing wind output, and thus reduce transmission costs.

The G-TNUoS regime attempts to approximate these effects on transmission costs by incorporating sharing factors into the year-round charge and scaling generators' year-round TNUoS charges by ALF. While these methods for setting locational charges may be

imperfect, the absence of any attempt to control for such effects within the D-TNUoS methodology suggests there is a strong case for a wider reform of the methodology, and not simply for a focused revision to so-called “embedded benefits” and/or the residual element of the D-TNUoS charge.

Additionally, as the modelling presented in Chapter 5 shows, there is some evidence that the current degree of locational variation in TNUoS charges understates the locational variation in the Long-Run Marginal Cost (LRMC) of transmission. This further supports the overarching need to correct the current distortions to locational signals, before implementing changes to the residual charge. In particular, improving the cost-reflectivity of the locational charge could result in more revenue being collected through this element of the charge, and thus reducing the growth in the expected residual charge that Ofgem cites as justifying some reform.⁵¹

4.2.2. The low proportion of revenue collected through the locational charge is symptomatic of flaws in the locational charge

The intention of the current methodology is to recover the costs of transmission from those parties driving the need for this transmission. Through this approach, as Ofgem describes, “cost reflective charging targets the costs of establishing and operating transmission infrastructure on the users of the system who impose those costs”.⁵²

It is therefore rather surprising that, under the current charging methodology, only 10% of total “wider” transmission revenue⁵³ (wider locational charge plus residual charge) comes through the locational elements of the D-TNUoS and G-TNUoS charges, with the majority coming through the residual charges. In fact, as Table 3 shows, the revenue raised through the locational D-TNUoS charge is close to zero. Following the logic set out in the Ofgem Open Letter, that this wider locational component is designed to be cost-reflective, it is surprising that it should recover such a small proportion of total cost.

⁵¹ Ofgem Open Letter, page 4, 5.

⁵² Ofgem (25 July 2014), Project TransmiT: Decision on proposals to change the electricity transmission charging methodology, para 1.4.

⁵³ This 10% refers to the share of the total revenues from the wider locational charges (£247.87 million) in total revenues from TNUoS charges (£2,872.98 million).

Table 3
G/D-TNUoS Revenue Recovery Breakdown (Locational and Residual Charge) (£m)

2016/17	Wider locational charge	Residual charge	Local circuit/ substation tariff	Total
Demand	-6.40	2,282.81	-	2,276.41
Generation	254.27	101.97	240.34	596.57
Total	247.87	2,384.78	240.34	2,872.98

Source: National Grid⁵⁴

As we discuss above, one reason why this locational charge raises a relatively small amount of revenue is the choice of reference node. If the reference node were further north, the locational D-TNUoS charge would tend to recover less revenue and the locational G-TNUoS charge would tend to recover more revenue (and vice versa if it were moved further south).⁵⁵ However, another possible cause of the relatively small amount of revenue collected through the locational element of the charge is that there are further flaws in the locational element of the charge. For example, as the modelling presented in Chapter 5 demonstrates, there is evidence that the locational signals conveyed by current D-TNUoS charges are too “flat” across the country and that the calculation procedure does not accurately reflect the underlying LRMC of transmission, which was the original intent of the ICRP methodology as we discuss further in Section 5.2.

4.2.3. Ofgem should consider reforms to the locational charge before considering “sticking plaster” reforms targeting the residual

While it is beyond the scope of this report to assess the specific flaws in the locational element of the charge and the reforms needed to address them, it is clear from the discussion above that Ofgem should not automatically assume that the level and design of the demand residual charge is at fault. Rather, National Grid’s forecast growth in the demand residual charge may very well be a symptom of other problems with the TNUoS methodology that would be better addressed through different types of modification to the ICRP model, and not a move to gross charging (see below) or a targeted freeze/reduction in the demand residual. Reforms that address the demand residual charge directly, unless they are linked to an assessment of what cost it is appropriate to socialise through this form of charge (see below), would represent “sticking plasters” that do not address wider problems with the methodology, and may create new distortions with unknown consequences as we explain below.

In particular, in considering potential reforms of the TNUoS methodology, Ofgem should consider whether the current locational charges accurately signal the costs that different types

⁵⁴ National Grid (2015), *TNUoS Tariff Forecast from 2016-17 to 2019-20*.

⁵⁵ In the example in Figure 6, shifting the reference node to the far south of the system would reduce the demand residual charge from around £43/kW to around £30/kW. We estimate that shifting the reference node in this way would increase revenues recovered through the locational element of the charge to around 32% of total MAR allocated to D-TNUoS.

of users in different parts of the system impose on the network. A related question is to what extent transmission costs should be targeted on the network users deemed (through the ICRP load flow model) to be driving the need for transmission capacity, and which costs should be socialised on the basis that they are not attributable to any particular network user. For instance, the expansion constant is the parameter of the TNUoS methodology through which transmission costs are targeted on transmission users via the locational charge. As we discuss in Chapter 5, there is an argument that this parameter is currently set at a level that is below the LRMC of transmission expansion.

4.2.4. Reforms of the locational charge should consider what proportion of transmission cost it is efficient to target on network usage

The question of what categories of transmission cost should be imposed on particular users appears not to have been thoroughly addressed by the CMP264/5 working group process. For instance, the following statement in the working group's consultation belies a lack of consideration on which elements of transmission costs are related to the provision of transmission infrastructure and which costs should be socialised because they cannot be attributed to particular users:

“The purpose of the Demand Residual tariff element is not to provide a locational price signal (which is achieved via the locational tariff element), but to recover the bulk of the costs that relate to the existing transmission network such as depreciation, return, direct and indirect operating costs. Some workgroup members believe... It could therefore be described as a form of ‘taxation’ aimed at collecting the revenue required to pay for a ‘public good’ delivered to all consumers (“demand”) as they benefit from the existence of the transmission network”.⁵⁶

In fact, it is economically efficient to allocate the costs of building operating and maintaining transmission assets to the categories of user who create the economic need for them, and thus encourage efficient behaviour. Given that transmission investment costs are recovered through regulatory allowances for depreciation of and a return on historic investment costs, it is misleading to suggest that these categories of transmission costs should be recovered through some form of socialised charge (or “taxation”), and not be imposed on the users that cause these costs. In fact, depreciation and maintenance are an intrinsic part of the costs of developing and operating the transmission system. As such there is a strong economic case for allocating those costs to the parties deemed to have caused them.⁵⁷

On the other hand, there may be some costs that are genuinely impossible to associate with any particular network user, such as those categories of costs that would not change

⁵⁶ National Grid (2016), Stage 02: Working Group Consultations *CMP264: Embedded Generation Triad Avoidance Standstill and CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market*. Paragraph 3.2.24.

⁵⁷ Ofgem's references to “fixed” and “sunk costs” also appear misleading. Transmission network capacity is built to serve network users. Once provided, the costs of providing that transmission are sunk, but at the point of provision the investment was avoidable. Hence, it is economically efficient to signal these costs through TNUoS charges. The vast majority of transmission costs could also be described as “fixed” in the sense that they are capital costs that do not vary with output (eg. MWh transported) and cannot be avoided in the very short-term. However, transmission investment requirements vary with the behaviour of network users, and as such are not fixed in the medium to long-term.

materially as the size of the transmission system changes. These would sometimes be referred to as “common” costs. However, further work would be needed to identify the bases on which it is appropriate to allocate any common costs to network users.

4.3. New Distortions from Proposed TNUoS Modifications

4.3.1. Distortions created by a move to gross charging

A number of the proposals put forward through the working group assessing CMP264 and CMP265 would introduce elements of gross charging, whereby the production from embedded generation is no longer netted off from suppliers’ load for the purposes of calculating their liability to pay D-TNUoS. At the same time, embedded generators will be subject to a different set of charges than those faced by consumers. In effect, the modifications tend to exempt embedded generators from paying (or receiving as a revenue) certain elements of the current D-TNUoS charge.

By setting the D-TNUoS charges embedded generators receive equal to the negative D-TNUoS charges consumers have to pay, the current method of net charging for D-TNUoS recognises that marginal increases in embedded generation imposes the same cost on the transmission system as marginal reductions in net demand through other means, such as demand response or generation behind the meter. A move to gross charging, especially if it introduces large differences between the TNUoS charges associated with these alternative means of reducing net demand, could lead to a range of new distortions.

In particular, small embedded generators subject to D-TNUoS charges (large industrial consumers in particular) would have strong incentives to place generation behind the meter, which could be less efficient than developing embedded generation with their own connections to the distribution system. This would enable them to continue to offset consumers’ liability to pay D-TNUoS for their consumption in the triad. It would also distort competition between embedded generation and demand side response providers, which provide very similar services to the power system in respect of reducing peak demand.

Hence, while a number of proposals have been put forward to change the TNUoS methodology in a way that claims to address a problem with D-TNUoS that distorts competition between large/transmission-connected and small embedded generators, the modifications would create new distortions. The effect of such new distortions needs to be assessed before it is possible to tell whether the proposed modifications are likely to improve efficiency, and thus whether they are in the consumer interest (see Section 4.4 below).

4.3.2. Distortions created by differential treatment of existing and new embedded generation

Some of the proposed modification would result in distorted competition between existing and new embedded generators. In particular, CMP264 would only apply to those connecting to the system after 2017, thus giving owners of existing embedded generation strong incentives to keep these existing plant operating for as long as possible, even where replacement would be more efficient.

Any decision to introduce differential treatment of embedded generators for new and existing plants (as under CMP264, for instance) would therefore need to explain why new distortions it creates are less detrimental to competition and economic welfare than the distortions Ofgem suggests are present in the current model.

4.3.3. Distortions created by the removal of locational signals for some embedded generation

As we discuss in Chapter 2, one of the key roles of TNUoS charges is to send economic signals to network users regarding differences in the transmission system costs they impose, depending on where in the country they are located. Despite this important role of TNUoS charges, a possible distortion arises from the modifications that propose that some or all embedded generators should face locational D-TNUoS charges that are constrained to be zero in circumstances where the load flow modelling suggests locational charges should be positive or negative.⁵⁸

For instance, we understand that CMP264 proposes to set zero locational D-TNUoS charges for all embedded generators. Other modifications would impose a floor on D-TNUoS of zero (to address the problem discussed below in Section 4.3.5 below), thus compressing locational signals in circumstances where the locational charge would otherwise be negative in some parts of the country.

A significant body of work conducted through Ofgem's recent Project TransmiT process identified a significant welfare loss associated with socialised (ie. non-locational) G-TNUoS.⁵⁹ The removal of locational signals from the D-TNUoS charges faced by new embedded plants could also have serious detrimental welfare consequences. Competition between new embedded generation sites could be distorted, through developers ignoring differences in the cost their projects impose on the transmission system depending on where they are located.

4.3.4. Distortions from applying different charges to plants with and without Capacity Market contracts

Some proposed modifications (notably CMP265) link embedded generators' eligibility to receive a revenue stream from negative D-TNUoS (only the residual component) to whether these generators have secured a Capacity Market contract. This aims to address the effect of the purported distortion that current TNUoS arrangements suppress Capacity Market clearing prices, which can be influenced by smaller plants embedded within distribution systems.

However, the approach proposed through CMP265 creates a new distortion in respect of existing embedded generators. Specifically, these generators will factor the opportunity cost of securing a Capacity Market contract into their Capacity Market offer prices. This opportunity cost will include the loss of D-TNUoS revenues.

⁵⁸ Note, a distortion does not necessarily arise from setting the locational element of TNUoS charges close to zero close to the reference node, where the locational charge should be set close to zero by definition.

⁵⁹ For example: Redpoint Energy (December 2011), *Modelling the Impact of Transmission Charging Options*, Table 6.

Consider the following example. Under current arrangements, an embedded generator's Capacity Market offer price will be determined by the difference between its fixed costs and expected earnings. Those include its expected earnings from the energy and ancillary services markets as well as its D-TNUoS revenues. And if the plant is profitable without any additional revenue, it may well be willing to bid (close to) zero in Capacity Market auctions. This situation is illustrated in the right hand column of Table 4.

However, if on securing a Capacity Market contract the generator would lose its D-TNUoS revenue stream (or some share of it), its bid price would be higher. Under this example, the generator would lose a £40/kW cash flow, so its bid into the Capacity Market auction would need to be at least £40/kW.

Table 4:
Illustrative Derivation of an Embedded Generator's Capacity Market Offer Price
Under Current TNUoS Arrangements

Cost / Revenue Stream		Value
Fixed Cost (Capacity and Fixed O&M Costs)	(a)	£20 /kW
D-TNUoS Payments for Embedded Generator	(b)	£40 /kW
Earnings from Energy Market	(c)	£20 /kW
Offer Price to CM	$\text{Max } [0, (a)-(b)-(c)]$	£0 /kW

This approach to charging would distort competition between embedded generators and larger/transmission connected plants which impose the same costs on the transmission system, potentially leading existing embedded plants to close earlier than is economically efficient. It may also artificially inflate the Capacity Market prices paid by consumers. However, further analysis, such as modelling of the energy market and Capacity Market auction outcomes would be required to quantify this effect.

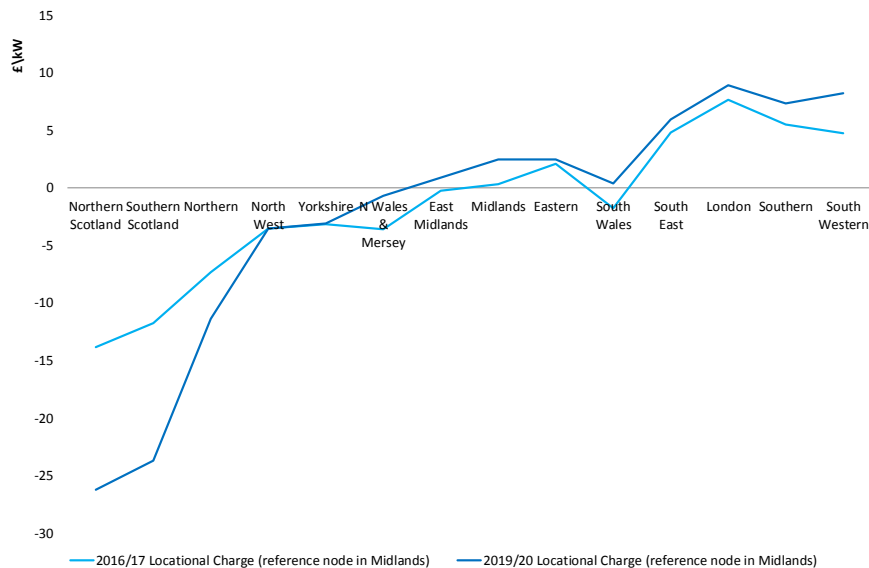
4.3.5. Distortions from removing the residual charge and setting negative D-TNUoS charges

A number of proposed modifications to the D-TNUoS charges (including CMP265 and a number of variants) envisage removing the demand residual element of the charge for embedded generators.

The effect of this change could be for embedded generators in some zones to face negative locational charges, that is embedded generators would need to pay for their generation. For instance, Figure 7 below shows that in some zones (eg. in Northern and Southern Scotland, in the North and North West and also in Yorkshire and North Wales), embedded generators' D-TNUoS charges, without the residual element, would be negative at present. Because these charges would be linked to embedded generators' production during peak periods (defined by the triad – see above), generators in zones with negative D-TNUoS charges would receive a

very strong economic signal not to produce during peak demand periods. Some affected generators would require the energy market price to reach thousands of pounds per MWh before they would be willing to generate and thus incur TNUoS costs.

Figure 7
Locational Charge if Reference Node in the Midlands



Source: National Grid⁶⁰

We understand that certain other variants on the original CMP264/5 modifications propose to address this problem by setting a floor on this element of the charge at zero. However, this approach raises the concern set out in Section 4.3.2 above, that it would weaken locational signals between those TNUoS zones with positive and negative locational charges for embedded generators, and completely remove the locational signal within the zones with zero locational charges.

4.4. The Need for Further Analysis to Assess the Impact of New Distortions

As set out above, many of the proposed revisions to the TNUoS methodology put forward through the CMP264/5 working group process would introduce significant new distortions to competition. Ultimately, such distortions will introduce new sources of inefficiency that act against the customer interest.

Ofgem may consider that there are trade-offs between existing distortions in the current methodology that are addressed by the proposed modifications and any new distortions they introduce. As we describe above, this would be an unsound position to adopt, because the logical basis for the purported distortion in the current methodology is extremely weak. However, at the least, we would expect Ofgem to make some effort to estimate the welfare

⁶⁰ National Grid (2015), *TNUoS Tariff Forecast from 2016-17 to 2019-20*.

consequences associated with the new distortions it would create by accepting the modifications put forward through the working group process. The welfare costs imposed by the new distortions would need to be traded-off against the welfare improvements Ofgem believes the modifications deliver. To date, as far as we are aware, the CMP264/5 working group has not made any assessment of the likely welfare effect of new distortions.

However, we recognise that such an assessment would take some time to complete. As we discuss further below in Section 4.6, the effort required to assess the economic rationale for introducing stop-gap measures could be better directed towards developing a more enduring solution to the range of problems with the current TNUoS methodology, such as those we discuss in Section 4.2.

4.5. Potential for New Sources of Undue Discrimination

As we describe in the previous section, many of the modifications put forward through the working group process introduce new charging structures for embedded generation. These create a range of economic distortions that are likely to detrimentally affect welfare. In addition, for reasons similar to those set out above, the proposed CUSC modifications would also introduce new sources of discrimination between different types of user, despite them imposing the same cost on the system (“undue” discrimination):

- Embedded generators impose the same cost on the transmission system irrespective of whether or not they are behind the meter, and whether or not they connect to the system before or after 2017. Through the introduction of gross charging, some of the proposed modifications appear to introduce a new source of undue discrimination, between those embedded generators which are located “behind the meter” and those which are not.
- Similarly embedded generators impose the same cost on the transmission system through net demand reduction as providers of demand side response. Some proposed modifications therefore introduce undue discrimination between embedded generators and demand side response through the introduction of gross charging and the definition of new charging arrangements specifically targeting embedded generators.
- Whether a generator connects to the system before or after a certain date does not affect the costs it imposes on the transmission system. CMP264 introduces different treatment for embedded generators connecting after a certain date, and hence a new source of undue discrimination between those embedded generators that connect before or after 2017.
- CMP265 differentiates charges according to whether a generator has a Capacity Market contract, which has no effect on the transmission costs they impose on the system. This approach to charging also creates a new source of undue discrimination.
- Those modifications that artificially compress locational signals (eg. through a floor of zero on the D-TNUoS charges that the load flow modelling suggest should be negative) or remove the locational charge altogether also introduce a new source of undue discrimination, by setting the same tariffs for plant in different locations, despite them imposing different costs on the grid.

4.6. The Lack of Rationale for a Stop-Gap Measure

Both CMP264 and CMP265 are designed as “stop-gap” measures which suggest possible corrections to a purported distortion associated with the current D-TNUoS methodology and the residual charge in particular. Even those modifications that purport to be “enduring” solutions have a number of limitations (see our discussion of potential new distortions in Section 4.3 above), and hence would probably need to be reformed subsequently. Therefore, all CUSC modification proposals we have seen to date would in effect constitute stop-gap measures.

As we describe above, the distortion inherent in the current methodology is not as significant as the Ofgem Open Letter and the Working Group consultation seem to suggest. In particular, this is due to the incorrect characterisation of the locational element of the charge as cost-reflective and the residual as a charge designed to cover “fixed/sunk” costs (see Section 4.1). There are also a number of other distortions that could be created by the interventions currently proposed through the proposed modifications which undermine the case for implementing these (or similar) reforms.

However, leaving aside these problems with the proposed modifications, from the evidence in the Open Letter and the Working Group consultation, there seems to be little case for introducing any stop-gap measure. First, the proposed changes could introduce new and serious distortions to market participants’ operational and investment incentives, in order to address an alleged distortion, of which the logical foundations are extremely weak.

Second, the main concern Ofgem expresses in the Open Letter relates to the impact of the D-TNUoS charging methodology on Capacity Market outcomes, and the ability of larger power stations to compete against smaller embedded ones. In particular, we understand that the clearing price in the Capacity Market has been set most recently by relatively small embedded diesel-fired generation units, which may have banked on receiving significant D-TNUoS benefits when selecting their Capacity Market offer prices.

If Ofgem is concerned about similar effects in subsequent Capacity Market auctions, a more proportionate remedy would be for Ofgem to signal promptly its intent to reform the current methodology in a way that corrects the distortion it believes exists, and to put in place a process of reform to identify more cost-reflective charging methodologies with the aim of producing remedies that are less distortionary and discriminatory than those currently proposed. This process of reform could be completed well-ahead of 2020, when the new contracts that are currently being procured through upcoming Capacity Market auctions would begin.

5. Modelling to Assess the Case for Reforming Locational Charges

As set out in Section 4.2, there are a number of problems with the locational element of the current D-TNUoS charge that may be limiting the amount of revenue it recovers from network users. As such, to address any potential problems associated with expected growth in the demand residual charge, it may produce more efficient outcomes and improve cost-reflectivity to modify the locational rather than the residual element of the charge.

To test this hypothesis, we have used Imperial College's Dynamic Transmission Investment Model (DTIM) to estimate the amount of revenue that would be recovered through locational TNUoS charges linked to the Long-Run Marginal Cost (LRMC).

As we discuss further below, the notion that locational TNUoS charges should reflect the LRMC of transmission is entirely consistent with the philosophy of the ICRP methodology. The ICRP methodology is itself an attempt to estimate the LRMC of transmission and to reflect the estimated costs in the charges faced by the different network users.

5.1. Overview of the Methodology

The DTIM model is a load flow model, built to reflect real conditions on the British electricity transmission system.⁶¹ It takes data on the mix and location of generation (capacity, availability, marginal cost of despatch) and on the profile of net demand⁶² on the transmission system. It then optimises the despatch of generation and investment in transmission assets, essentially making a least-cost trade-off between transmission investment and constraint costs. In optimising transmission investment, DTIM examines a range of different levels of demand and wind output, to account for a wide range of different conditions that influence the efficient level of transmission investment.

Once DTIM has optimised the investment in transmission infrastructure, we can use its outputs to estimate the *change* in transmission investment costs that would result from marginally changing the amount of generation installed at different locations, or in the amount of net demand at different locations. The cost of these marginal changes in efficient transmission investments defines the LRMC of transmission associated with marginal changes in generation or demand.

For this assignment, Imperial has taken data on the mix of generation and future demand growth from the database of generation and demand that National Grid used to produce its latest forecasts of TNUoS charges.⁶³ The results presented are for two charging years (2016/17 and 2020/21). More details on the methods and assumptions used in this modelling are presented in Appendix A of this report.

⁶¹ DTIM has been used by Imperial College for a wide range of project assignments, most recently to support the Competition and Market Authority's Energy Market Investigation, and the impact of its remedy to implement zonal transmission loss multipliers.

⁶² Net demand is defined as demand, less output from embedded generation.

⁶³ National Grid (2 February 2015), *Forecast TNUoS tariffs from 2016-17 to 2019-20*, Section 3.3 and 3.6.

5.2. The Concept of LRMC as a Benchmark for Cost Reflective TNUoS Charges

As set out above, one of the key objectives of the TNUoS methodology is to set tariffs that send efficient locational signals to network users. In practice, it seeks to do so by setting TNUoS charges that reflect differences in the LRMC of transmission required to accommodate users of different types at each node on the network.

National Grid recognised the importance of LRMC as a standard for efficient transmission tariff design in its original 1992 review of transmission access charges, noting that “the valuation of long run marginal costs is a natural starting point for tariff design in a capital intensive, regulated industry”.⁶⁴ National Grid therefore developed the original ICRP methodology as a means of broadly approximating the LRMC of transmission,⁶⁵ in part because a methodology that more closely approximated LRMC would have introduced too much complexity into the charging methodology.⁶⁶

However, it is possible, when designing a TNUoS methodology, to estimate how closely the proposed tariffs approximate the LRMC of transmission. For example, in 1992, National Grid estimated LRMCs “properly, by comparing the differences in investment costs between two scenarios and a base case with the differences in revenue yielded by the [ICRP] for transport in the imaginary system”.⁶⁷

Thus, while the current TNUoS methodology is not based on the detailed calculations of LRMC, LRMC is the correct benchmark against which to assess the cost-reflectivity of the transmission charging methodology, as National Grid’s past practice indicates. As such, the Imperial modelling seeks to estimate locational charges that reflect the LRMC of transmission associated with demand in different parts of the system, and to estimate the amount of revenue that these charges would recover.

The procedure for calculating LRMC within DTIM is designed to represent as closely as possible the methods for calculating LRMC built into the “philosophy” of the ICRP methodology. For instance, the calculation of LRMCs is based on an optimally-sized network without regard to the current capacity of the transmission system. Like the ICRP

⁶⁴ National Grid, 30 June 1992, *Transmission Use of system Charges Review*, Proposed Investment Cost Related Pricing for use of System, page 41.

⁶⁵ We conclude that National Grid intended that the ICRP methodology should approximate LRMC because it notes that the optimisation problem required to implement these calculations “solves for the LRMCs of each node”.

Source: National Grid, 30 June 1992, *Transmission Use of system Charges Review*, Proposed Investment Cost Related Pricing for use of System, page 52.

⁶⁶ National Grid considered another LRMC-based charging methodology as part of its 1992 review, referred to as “scenario based LRMC”, which aims to provide a more accurate estimate of LRMC than the ICRP approach by taking into account the likely level and location of demand and generation on the UK transmission network over a thirty year period at three or five year intervals. However, National Grid doubted whether such a method could be accurately applied.

Source: National Grid, 30 June 1992, *Transmission Use of system Charges Review*, Proposed Investment Cost Related Pricing for use of System, page 43

⁶⁷ Ralph Turvey 2000, *What Are Marginal Costs and How to Estimate Them*, page 25.

methodology, it also estimates LRMC by considering small incremental changes in injections in each part of the system.

5.3. Baseline Modelling Results

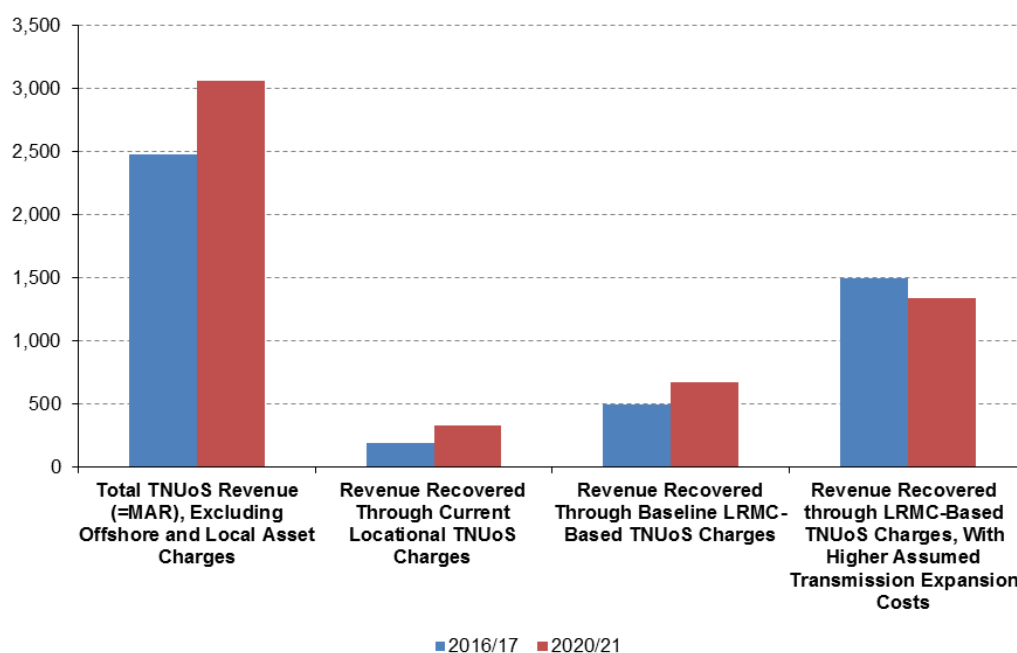
In performing this analysis, we have considered a range of costs associated with providing transmission capacity. In a “baseline” scenario, we assume onshore transmission expansion costs are £60/MW/km/yr, and £160/MW/km/yr for bootstrap investments. Then, in an alternative scenario we increase the cost of onshore reinforcement three-fold to £180/MW/km/yr. There are two key rationales for this scenario:

- First, the cost of expanding transmission capacity assumed in the baseline scenario (£60/MW/km/yr for onshore circuits) is calibrated to the marginal expansion costs implied by estimates put forward through the ENSG process (see Section A.2 in Appendix A). This figure represents the marginal cost of increasing transmission capacity, but it may exclude a range of costs associated with doing so. In particular, the cost of marginally expanding the onshore network to accommodate changes might be higher if expansions in transmission capacity need to be provided with N-2 redundancy, which could effectively triple transmission reinforcement costs. Arguably, all such costs associated with the provision of additional network capacity should be factored into the calculation of LRMC transmission, and the derivation of cost-reflective TNUoS charges.
- Second, as we describe in Section 4.2, the current TNUoS charging methodology recovers only a very small proportion of total MAR through the locational element of the charge. As we discuss above, this calls into question the efficacy of the locational elements of the charge in signalling the impact that network users have on transmission costs. Increasing the assumed cost of expanding transmission capacity when we calculate the LRMC of transmission demonstrates the effect of targeting a greater share of total transmission costs on those network users that drive the need for transmission capacity.

Figure 8 compares the total revenue to be recovered through wider TNUoS charges (the first pair of bars on the left of the figure) against the revenue collected through the locational elements of the charge for 2016/17 and 2020/21 (second pair of bars from the left in the figure). Like Table 3 in Section 4.2.2, this figure illustrates that currently less than 10% of total revenues are collected through the locational element of the charge. As we discuss above, Ofgem asserts that this locational charge, which only recovers 10% of revenue, is the cost-reflective component of the charge.

The figure also shows that setting LRMC-based tariffs using our “baseline” assumptions on transmission costs would result in a moderate increase in revenue collected through the locational element of the charge to around 20% of total (see the third pair of bars). One of the main reasons for this modest effect on total revenue recovery is that the assumed marginal cost of expansion (£60/MW/km/yr) is not dissimilar to the expansion constant used in the current TNUoS methodology. However, when this is increased to £180/MW/km/yr, we see a material increase in the revenue collected through the locational element of the charge to around 60% of the total in 2016/17.

Figure 8:
Revenue Raised Through Alternative Transmission Pricing Methodologies (£m)



Source: Imperial College Modelling

5.4. Implications for the Reform of the TNUoS Methodology

Through the modelling exercise described in this chapter, we have estimated the revenue that would be recovered through the locational element of the charge, if it were set to better reflect the LRMC of transmission. The results demonstrate that this improvement could materially increase the amount of revenue collected through locational charges, and thus reduce the amount that needs to be collected through the residual. Following the discussion in Section 4.2, this modelling therefore provides further evidence that there is a need for some reform of the locational element of the charge, before any reform of the residual.

6. Conclusions

6.1. Conclusions on the Rationale for Reform

Ofgem's recent Open Letter on embedded benefits sets out its apparent belief that the current methodology for setting the TNUoS charges faced by smaller embedded generators is not cost-reflective, and is distorting competition between smaller and larger generators. The root of Ofgem's concern seems to be the demand residual component of the charges, which it characterises as not cost-reflective and designed to recover "fixed/sunk" costs. By contrast, it characterises the locational elements of the wider TNUoS charges as being broadly cost-reflective, albeit recognising some areas for possible improvements in the economic signals they send.

There are a number of problems with Ofgem's critique of the current methodology, and the potential case for reform set out in its Open Letter. In particular, the decomposition of the D-TNUoS charge into a supposedly cost-reflective locational component and a residual that only exists to recover "fixed/sunk" costs is entirely artificial:

- The locational element of D-TNUoS charges is only "cost-reflective" in the sense that it emerges from a load flow modelling exercise that seeks to estimate the degree to which costs *vary* by location. Hence, the locational charge seeks to reflect only the degree of variation in charges across the country.
- The *level* of the locational charge – and by implication the level of the demand residual charge – is in no sense cost-reflective. In fact, it depends on regulatory decisions on the G:D split (currently determined by EU regulations) that have not been justified with reference to cost reflectivity, and on the choice of the reference node within the load flow model.

Ofgem is therefore wrong to characterise the locational element of the D-TNUoS charge as cost-reflective, and to characterise the residual component as not cost-reflective. As such, the logical foundation for Ofgem's critique of the current TNUoS methodology and the reforms it appears to be contemplating are extremely weak.

Rather than there being a problem with the residual charge itself, any problems with the current methodology probably arise mainly from problems with the locational element of the charge. For instance, the D-TNUoS locational charge does not account for differences in the transmission costs that users impose on the system in off-peak conditions, which is an increasingly important driver of transmission investment.

As evidence of this problem with the locational charge, we observe that it recovers only a very small proportion of total transmission costs, leaving a large amount of revenue to be recovered through the residual. This suggests that the locational element of the charge does not target the full costs of providing transmission capacity on the parties that drive transmission costs. Modelling by Imperial College also suggests that if the locational element of the charge were set closer to LRMC, the amount of revenue the locational charge recovers could increase materially. Therefore, flaws with the locational element of the charge mean that Ofgem's concerns about the rising level of the residual could be addressed more effectively through reform of the locational element of the charge.

Moreover, as we discuss in this report, while Ofgem seems to be concerned with potential distortions to competition between large and small generators, the modifications it is currently considering introduce new distortions to competition. In particular, the current approach to net D-TNUoS charging ensures a common treatment for net demand reduction, however it is achieved (eg. demand response, embedded generation, etc). As we discuss below, by introducing gross charging for embedded generation, the modifications Ofgem is considering would create a range of new distortions to competition between alternative means of reducing net demand.

6.2. Flaws in the Proposed Modifications

The Ofgem Open Letter also invites industry participants' views on the remedies that have been put forward to the supposed distortion that Ofgem identifies (CUSC modifications CMP264 and CMP265) as well as variants that we understand have been put forward through an ongoing working group process.

All of these modifications introduce “gross charging”, which means embedded generators' output would cease to be netted off from demand for the purpose of computing suppliers' D-TNUoS charges. Instead, embedded generators' TNUoS costs would be calculated separately (ie. on a gross basis), and we understand that many of these modifications involve materially reducing the extent to which embedded generators receive the negative demand residual as one component of their TNUoS charge (or revenue).

The economic basis for these changes is extremely weak, because it relies on Ofgem's assertion that it is possible to decompose the current charge into some components that are cost-reflective and others that are not. Decomposing the charge in this way is not meaningful, for the reasons described above. As such, the proposed gross charging methodologies that effectively remove the demand residual from embedded generators' TNUoS charges are also unjustified on grounds of cost-reflectivity.

Even if it were meaningful to decompose charges in this way, we have identified a series of potential flaws with these proposed modifications to the charging methodology:

- A number of the proposed modifications introduce elements of “gross charging”, which means charging arrangements will differ for embedded generators and consumers who may have generation capacity “behind the meter”, and for providers of demand side response. Embedded generation, generation located behind the meter and demand response all impose the same cost on the transmission system, which should be reflected in the charges. The proposed change towards gross charging of embedded generators could materially distort competition between distributed energy resources, creating a new source of inefficiency. Neither Ofgem nor the working group have sought to evaluate the effect of such distortions from introducing a new source of undue discrimination into the charging methodology.
- We understand that some modifications, including CMP264, introduce differential treatment for new and existing embedded generators, which will further distort competition between these categories of plant resulting in potentially inefficient closure/investment decisions. This approach also introduces undue discrimination, because whether a generator connects to the system before or after some arbitrary date does not affect the costs they impose on the transmission grid.

- Some modifications, including CMP265, introduce differential treatment for embedded plants, depending on whether they have obtained a Capacity Market contract. This approach will distort existing generators' incentives to bid into the Capacity Market auctions, as they will need to factor in the cost of losing D-TNUoS revenues when setting their bids. This approach also introduces undue discrimination, as whether generators have a Capacity Market contract would not influence the costs they impose on the transmission system.
- CMP265 and some other alternative proposals we understand have been put forward also exempt some embedded generators from receiving the residual component of the D-TNUoS charge. Aside from being unjustified on grounds of cost-reflectivity as we discuss above, this approach would result in some generators facing negative D-TNUoS. Because of the link between D-TNUoS and triad production, this change would provide a material disincentive for some embedded generators to produce during peak periods, which could cause extremely high peak wholesale energy prices, and possibly even hamper security of supply, if the disincentive (per MWh) is close to the effective price cap in the balancing mechanism.
- Those modifications which artificially compress locational signals, such as by setting locational charges to zero in cases when the load flow modelling suggests they should be negative, create a new distortion through the removal or dilution of locational signals. Variation in locational charges across the country is intended to send efficient locational signals to network users. Removing this charge could cause material inefficiency in the locational decisions of new plants, or the closure incentives for existing plant.

As set out above, many of the proposed revisions to the TNUoS methodology put forward through the CMP264/5 working group process would introduce significant new distortions to competition. Ultimately, such distortions will introduce new sources of inefficiency that act against the customer interest.

Ofgem may consider that there are trade-offs between existing distortions in the current methodology that the proposed modifications claim to address and any new distortions they introduce. As we describe above, this would be an unsound position to adopt, because the logical basis for the purported distortion in the current methodology is extremely weak. However, at the least, we would expect Ofgem to make some effort to estimate the welfare costs associated with the new distortions it would create by accepting the modifications put forward through the working group process, and to trade these off against the welfare improvements it believes the modifications deliver. To date, as far as we are aware, the CMP264/5 working group has not made any assessment of the likely welfare effects of new distortions.

6.3. The Lack of Rationale for a Stop-Gap Measure

A further problem with the proposed modifications is that they all represent “stop-gap” measures that either implement reforms that lapse when Ofgem implements more fundamental review of TNUoS pricing, or are in effect stop-gap measures because they fail to comprehensively address the current shortcomings of the D-TNUoS methodology.

In addition to the weaknesses in the logical foundation for the (presumably temporary) changes to TNUoS put forward so far, there is also little rationale for any reform pending more fundamental review by Ofgem.

Specifically, Ofgem's main concern appears to be the distortion to competition between investments in large transmission-connected plant and smaller embedded plant, which affects (amongst other things) the Capacity Market price. Apart from the fact that this distortion is unproven, addressing this concern does not require a change in TNUoS charges today, particularly when the modifications proposed introduce so many new distortions. It would be sufficient for Ofgem to signal its intent to reform TNUoS charges along certain lines in order to guide investors in new embedded plant as to the basis on which they should factor in the D-TNUoS revenue stream into their investment decisions and/or Capacity Market bid prices. Also, any more fundamental review of TNUoS charges could be in place before the start date of the Capacity Market contracts currently being procured through four year-ahead auctions.

6.4. Modelling to Assess the Case for Reforming Locational Charges

As we also discuss in this report, there are a number of problems with the locational element of the current D-TNUoS charge that may be limiting the amount of revenue it recovers from network users. As such, to address any potential problems associated with expected growth in the demand residual charge, it may produce more efficient outcomes and improve cost-reflectivity to modify the locational rather than the residual element of the charge.

To test this hypothesis, we have used Imperial College's DTIM model to estimate the amount of revenue that would be recovered through locational TNUoS charges linked to the Long-Run Marginal Cost (LRMC).

Through this modelling exercise, we have estimated the revenue that would be recovered through the locational element of the charge, if it were set to better reflect the LRMC of transmission. The results demonstrate that this improvement could materially increase the amount of revenue collected through locational charges from around 10% to around 60% of the total revenue recovered through "wider" TNUoS charges, and thus reduce the amount that needs to be collected through the residual. Following the discussion above, this modelling therefore provides further evidence that there is a need for some reform of the locational element of the charge, before any reform of the residual.

6.5. Conclusion

As set out in this report, the logical basis for the changes in the TNUoS methodology that Ofgem's Open Letter seems to be contemplating is extremely weak. In particular, the notion that the D-TNUoS charge can be split into the locational element of the charge that is cost-reflective, and the residual charge that represents a charge to recover the "fixed/sunk" costs of the network is entirely unjustified. The locational element of the charge is only designed to signal differences in the cost demand imposes across different locations, not the absolute level of transmission cost that demand imposes. The ratio between the two depends on regulatory decisions regarding what share of costs generation and demand should bear, and the arbitrary choice of reference node in the charging methodology.

If fact, rather than a problem with the residual charge, there are a range of flaws associated with the locational element of the charge. If these flaws were rectified, the locational element

of the charge would recover a larger amount of revenue, and the expected growth in the demand residual could be moderated.

In fact, the range of reforms to TNUoS arrangements put forward through the CMP264/5 working group process also introduce a range of new distortions that would detrimentally affect welfare. Any new reform aimed at addressing existing distortions would need to examine carefully the trade-off between the new distortions that the modifications would create.

Finally, there is also little rationale for any “stop-gap” reform, pending more fundamental review by Ofgem. If Ofgem’s main concern is the distortion to competition in the Capacity Market, it would be sufficient for Ofgem to signal its intent to reform TNUoS charges along certain lines in order to guide investors in new embedded plant as to the basis on which they should factor in the D-TNUoS revenue stream into their Capacity Market bid prices.

Appendix A. Details of the Imperial College DTIM Modelling

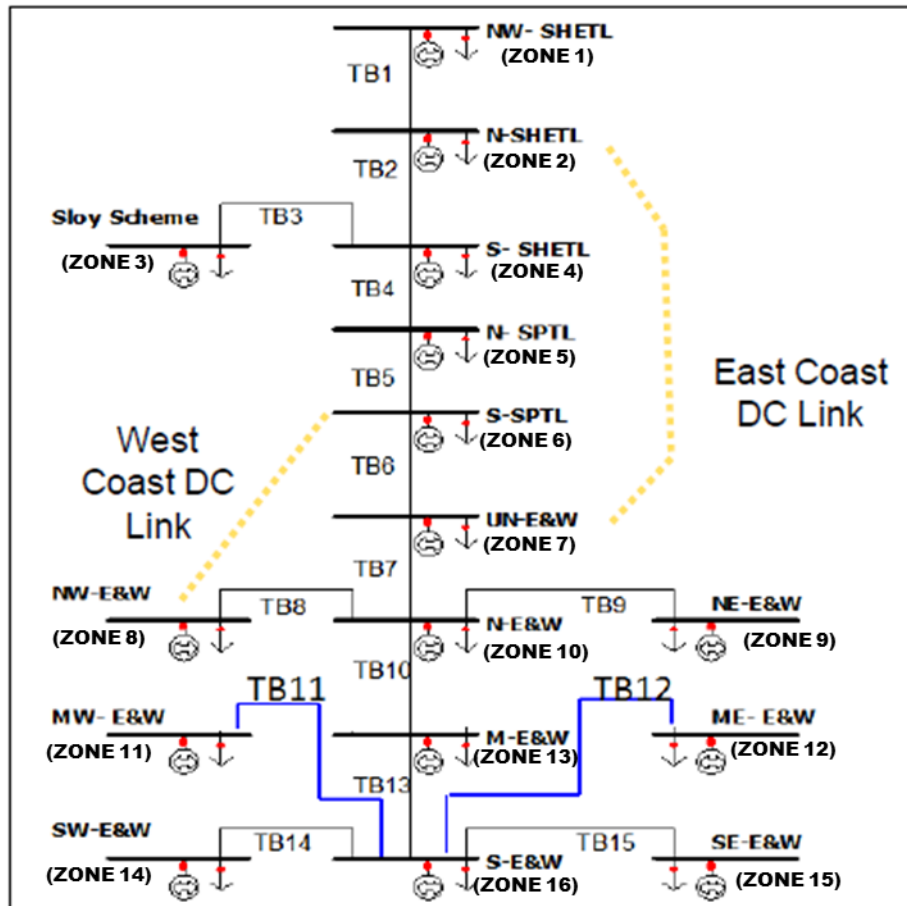
A.1. Overview of DTIM

Imperial's Dynamic Transmission Investment Model (DTIM) represents conditions on the British electricity transmission system. DTIM was developed by Imperial College/SEDG for the purpose of supporting optimal transmission investment decisions on the transmission system in Great Britain. DTIM balances the costs of network constraints against the costs of network reinforcement, minimising the overall cost of power system operation and expansion over a given duration. Throughout the optimization period the model determines when, where and how much to invest in providing transmission capacity using data inputs including a demand forecast, generators' bid/offer prices, evolution of installed generation capacity, the location and quantity of new wind capacity, transmission and generation maintenance plans, etc.

DTIM uses a 16-zone, 15-boundary radial network to represent the GB transmission system, as shown in Figure A.1. Each node represents a part of Great Britain, and each branch represents a boundary.⁶⁸ In order to reflect the need for the HVDC bootstraps, DTIM includes constraints on maximum boundary capacities, the most important of which is the maximum capacity of 4.4GW on the Cheviot boundary (ie., any further increase in Scotland – England transmission capacity can be delivered only through the HVDC links in DTIM).

⁶⁸ The network was developed by Imperial College and has been used extensively in the past for supporting the CMA's Energy Market Investigation, the Transmission Access Review (TAR), the fundamental review of the SQSS, and by National Grid to validate a CBA exercise performed for the ENSG.

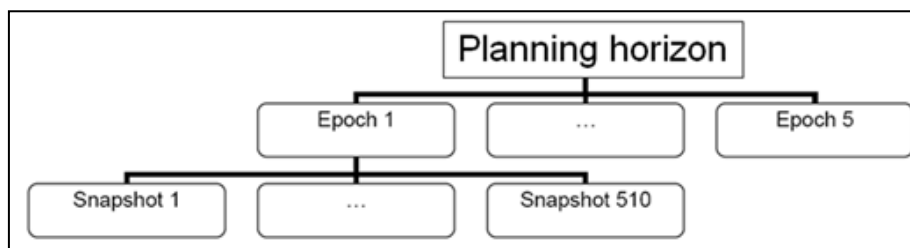
Figure A.1
DTIM Radial Network



Source: Imperial College

We run the DTIM model for the years 2016/17 and 2020/21 (each of which represent a DTIM “epoch”), as described in the body of the report. Then, each year (or epoch) is broken down into 510 representative snapshots (as shown in Figure A.2), designed to represent a range of fundamental demand and supply conditions.

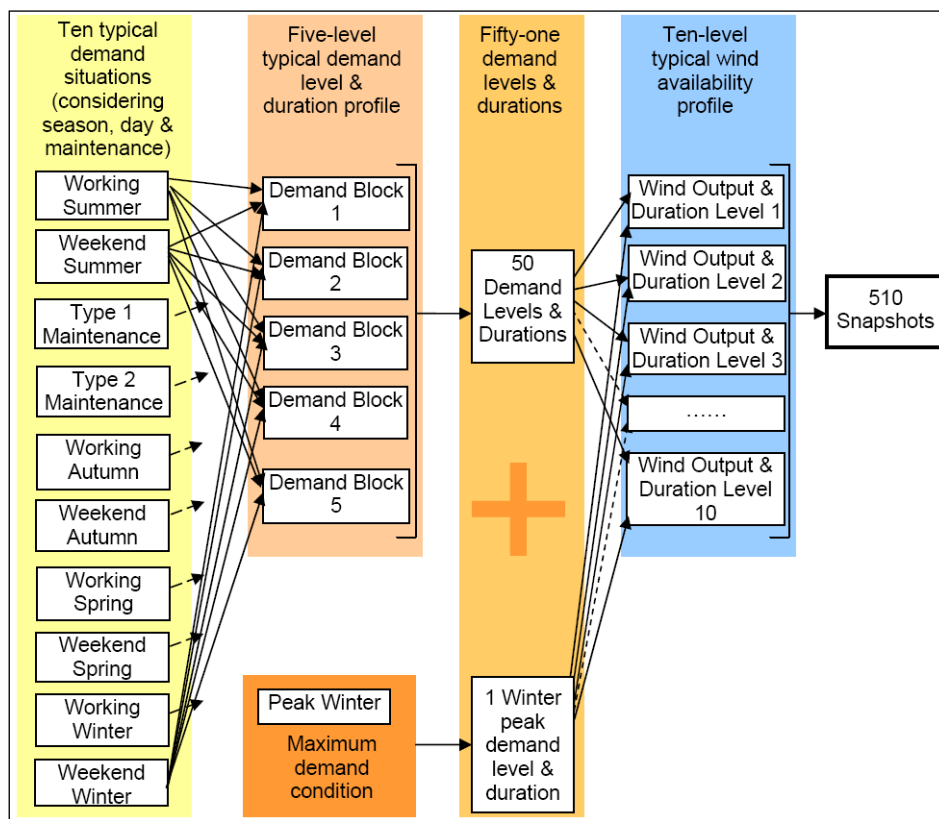
Figure A.2
DTIM Epochs



Source: Imperial College

The 510 snapshots are obtained by combining 51 demand levels with 10 wind output levels. Of the 51 demand levels (each with a duration specified within the model), one of them represents the level of winter peak demand, and the other 50 are derived from 5 daily demand blocks that apply on 10 typical days. The 10 typical days are working days and weekends for winter, spring, summer, autumn and boundary maintenance seasons respectively. The demand levels are adjusted to take into account any intermittent embedded generation including PV and hydro. Figure A.3 summarises this process.

Figure A.3
DTIM Snapshot Definitions



Source: Imperial College

A.2. Key Modelling Assumptions

A key data input assumption required for this study is the generation and demand background. These were taken from the latest TNUoS forecasts produced by National Grid for the years 2016/17 and 2020/21. We then mapped generation capacity DTIM nodes using published information on the location of existing generation or projects in the pipeline (for 2020/21). The generation capacities by technology/zone are shown in Table A.1 and Table A.2. Peak (net) demand in 2016/17 was assumed to be 50,848MW and 52,314MW in 2020/21.

Table A.1
Generation Capacity by Technology/Zone in 2016/17

	2016/17												
DTIM	Interconnectors	Wind Onshore	OCGT	Coal	Hydro	CCGT	Wind Offshore	CHP	Pump Storage	Nuclear	Wave	Tidal	Biomass
1	0	440	0	0	386	0	0	0	300	0	0	0	0
2	0	269	0	0	0	400	0	0	0	0	0	0	0
3	0	106	0	0	80	0	0	0	0	0	0	0	0
4	0	189	0	0	200	0	0	0	0	0	0	0	0
5	0	706	0	0	0	0	0	0	440	0	0	0	0
6	295	1880	0	0	0	0	0	120	0	2289	0	0	0
7	0	284	0	0	0	1522	986	155	0	3640	0	0	0
8	505	0	0	0	0	0	828	0	2004	0	0	0	0
9	0	0	0	0	0	540	609	1218	0	0	0	0	0
10	0	0	0	7348	0	4825	0	0	0	0	0	0	0
11	0	228	0	1735	0	3601	0	0	0	0	0	0	0
12	0	0	0	0	0	806	1449	0	0	1216	0	0	0
13	0	0	0	5001	0	3003	0	0	0	0	0	0	0
14	0	0	140	0	0	905	0	0	0	1261	0	0	0
15	4200	0	0	0	0	3822	930	0	0	1081	0	0	0
16	0	0	0	0	0	6950	816	158	0	0	0	0	0

Table A.2
Generation Capacity by Technology/Zone in 2020/21

	2020/2021												
DTIM	Interconnectors	Wind Onshore	OCGT	Coal	Hydro	CCGT	Wind Offshore	CHP	Pump Storage	Nuclear	Wave	Tidal	Biomass
1	0	1591	0	0	386	0	0	0	300	0	10	0	0
2	0	623	0	0	0	400	1168	0	0	0	0	154	0
3	0	281	0	0	80	0	0	0	0	0	0	0	0
4	0	327	0	0	200	0	0	0	0	0	0	0	0
5	0	1303	0	0	0	0	0	0	440	0	0	0	0
6	375	2694	0	0	0	0	2125	120	0	2289	0	0	0
7	1400	415	0	0	0	1522	1646	155	1500	3640	0	0	285
8	505	0	0	0	0	0	1828	0	2004	0	0	0	0
9	0	220	0	0	0	1855	6809	1218	0	0	0	0	0
10	0	0	0	7348	0	11022	0	0	0	0	0	0	400
11	0	228	299	1735	0	3900	2000	0	0	0	0	320	0
12	0	150	299	0	0	1105	2919	0	0	2886	0	0	0
13	0	0	0	5001	0	3923	900	0	0	0	0	0	0
14	0	0	140	0	0	905	0	0	0	1061	0	0	0
15	6200	0	0	0	0	7902	1666	0	0	1081	0	0	0
16	2900	0	0	0	0	8212	1221	158	0	1600	0	0	0

We used data from the latest National Grid ELSI model to define assumptions on the bid and offer prices (relative to the assumed Short-Run Marginal Cost of despatch) of the different generation technologies, as shown in Table A.3.

Table A.3
Generation Bid/Offer Prices (£/MWh)

Fuel Type	SRMC	Bid	Offer
Hydro	£0.01	-£50.00	£0.00
Offshore Wind	£0.01	-£100.00	£0.00
Onshore Wind	£0.01	-£50.00	£0.00
Wave & Tidal	£0.01	-£50.00	£0.00
Nuclear	£6.50	£0.00	£10.40
Biomass	£25.00	£15.00	£40.00
CHP	£27.71	£16.63	£44.34
CCGT	£45.35	£27.21	£72.56
Interconnection Europe	£44.22	£26.53	£70.75
Coal	£56.05	£33.63	£89.68
Interconnection Ireland	£54.65	£32.79	£87.44
Pumped Storage	£56.61	£33.97	£90.58
Oil	£130.14	£78.08	£208.22
OCGT	£171.17	£102.70	£273.88
Curtail	£4,000.00	£4,000.00	£4,000.00

As discussed in more detail below, calculating the LRMC of transmission involves running the standard transmission investment model of DTIM to build the optimum transmission system, and then re-running the model with fixed transmission to calculate LRMCs. The “baseline” modelling was performed using the standard transmission unit investment cost for the onshore and bootstraps given below.

Given the simplified boundary structure of the model, the cost of reinforcing each boundary depends on the assumed unit cost of transmission (in £/MW/km/yr), which is multiplied by the assumed thickness of each boundary (in km).

We therefore assume a uniform cost of reinforcement across the AC network of £60/MW/km/yr for all onshore circuits. In reality, we recognise that a diverse range of reinforcement options exists (eg. overhead lines vs. underground cables, reinforcements at different voltage levels, building new substations), the cost of which will vary. However, we assumed a uniform reinforcement cost of £60/MW/km/yr on the basis that it is a reasonable approximation of the average cost of adding boundary capacity to the onshore network. This is in line with National Grid estimates, as set out in the recent review into the NETS SQSS, which use three alternative methods to derive a high-level generic cost of reinforcement:⁶⁹

- *‘Ideal’ pricing, based on idealised reinforcements of overhead line.* This method yielded a reinforcement cost of £58/MW/km/yr;
- *Actual pricing, based on actual planned examples of network expansion outlined in a 2009 Electricity Network Strategy Group (ENSG) report.* National Grid converted ENSG

⁶⁹ National Grid April 2011, *NETS SQSS Amendment Report GSR009 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation*, Appendix 5, pages 58-59

estimates of total project costs into £/MW/km/yr reinforcement costs, which ranged from £100 to £240/MW/km/yr; and

- *Average pricing, based on TO revenues and installed capacity.* This method yielded reinforcement prices of £32, £58 and £41/MW/km/yr, for SHETL, SPT and NGET respectively.

In our modelling, the only type of investment to which we apply a different cost assumption is the offshore HVDC bootstraps, on the basis that these technologies are more expensive than conventional AC reinforcements. For the offshore bootstraps, we assume a reinforcement cost of £160/MW/km/yr.

We assume that the potential to expand all the key transmission boundaries in DTIM is not constrained, except for B6, the Cheviot boundary between England and Scotland. We allow DTIM to provide capacity using onshore circuits, up to 4.4GW, with any further capacity provided through bootstrap investments. The optimum boundary capacities selected by the model are shown in Table A.4 and Table A.5 below.

Table A.4
Optimised Boundary Investments in the Baseline in 2016/17

Boundary	Optimum Capacity 2016/2017 [MW]
L1	488.09
L2	624.71
L3	105.73
L4	575.16
L5	1,050.76
L6	2,092.61
L7	4,968.80
L8	2,307.64
L9	2,348.18
L10	7,407.12
L11	3,196.34
L12	2,487.05
L13	4,210.61
L14	844.03
L15	9,675.07

Table A.5
Optimised Boundary Investments in the Baseline in 2020/21

Boundary	Optimum Capacity 2020/2021 [MW]
L1	1,181.93
L2	2,384.22
L3	239.18
L4	2,578.12
L5	2,782.13
L6	6,434.18
L7	10,382.64
L8	1,622.61
L9	8,222.07
L10	13,823.21
L11	3,020.79
L12	4,757.52
L13	6,759.10
L14	1,676.26
L15	11,693.15

A.3. Method for Estimating LRMC

A.3.1. Overview of the methodology

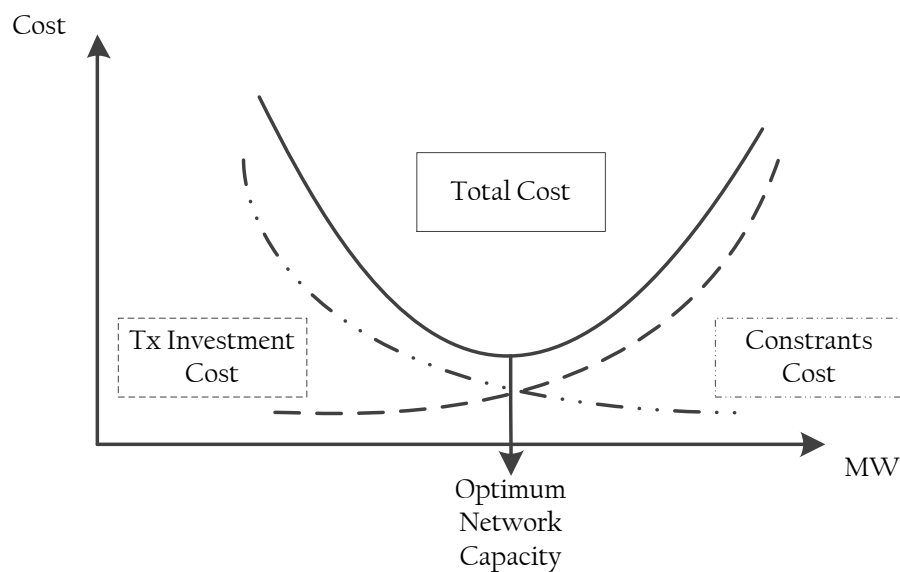
This section sets out in detail the methods we have employed to estimate the LRMC of transmission associated with marginal changes in net demand in each part of the transmission system using DTIM. We use the following approach:

1. We perform one run of DTIM so that, taking the mix of installed generation capacity as given, both generation dispatch and network investment is optimised, making a least-cost trade-off between constraints and investment. We use this run of the model to calculate net power injection at each node (for both generation and demand customers) under an efficient pattern of dispatch and transmission investment; and
2. In a second step, we then perform another run of DTIM, which takes these net injections (across the whole planning horizon) as given. Hence, in this second run, the model does not optimise dispatch, as the net injections already reflect an optimal dispatch. However, we do allow DTIM to build the least-cost transmission network to accommodate these flows. This procedure allows us to obtain the duals on the power flow constraints at each node, for every hour. These duals represent the marginal transmission reinforcement cost that the model incurs if demand at a particular node increases slightly. By aggregating these duals across the year we can identify the extent to which changes in demand at a particular node change total transmission costs, and thus impute the LRMC of transmission investment triggered by a marginal increase in demand at each node.

A.3.2. Step 1: optimising transmission network investment

As described above, we applied the DTIM model, which performs a Cost-Benefit Analysis (CBA) to balance the cost of network constraints against and the cost of network reinforcement to determine the optimal network investment strategy in each of the two years we model. The modelled patterns of investment minimise total systems costs, including generation operation costs and network expansion costs, as presented in Figure A.4.

Figure A.4
Illustration of DTIM Cost-Benefit Analysis Framework



Key input data in this optimisation include network topology, the demand profile forecast for each zone (node), current and future fuel costs, bid and offer prices, the assumed evolution of installed generation capacity, the location and quantity of new wind capacity and transmission and generation maintenance plans. We describe our assumptions on these key variables above. Throughout the optimization period considered the model determines when, where and how much to invest in network reinforcements.

In its simplest form, the model is formulated as a linear programming problem that minimises the sum of the Net Present Values (NPVs) of transmission investment cost and the cost of congestion in the system across a given multi-year period. As described above, DTIM divides the whole time horizon of the study into a number of stages (time blocks), referred to as “epochs” in the model. Yearly variations in operating scenario (conditions) driven by seasonal and daily changes in demand and wind, including consideration of transmission maintenance windows, are represented by 550 operating scenarios. These scenarios include one with no (or very low) wind output during peak demand, which is used to reflect the fact that wind has low capacity value and hence cannot displace network assets.

In a simplified form, the objective function of the network planning problem in DTIM is formulated as follows:

$$\min \sum_{t=1}^T \sum_{l=1}^{Nl} (k_{l,t} \cdot F_{l,t}^{inv}) + \sum_{t=1}^T \sum_{s=1}^{Ns} \sum_{g=1}^{Ng} (dur_{s,t} \cdot c_{g,t} \cdot P_{g,s,t}) \quad (1)$$

Where:

- t denotes each of the T time blocks in the modelling horizon;
- l denotes each of the Nl transmission boundaries represented in the model;
- $k_{l,t}$ is the unit cost of transmission investment for boundary l at time t ;
- $F_{l,t}^{inv}$ is the additional transfer capacity for boundary l proposed to be implemented in epoch t , which is selected endogenously by the model;
- s represents each of the Ns operating scenarios within a year;
- g represents each of the Ng generators on the system;
- $dur_{s,t}$ is the duration (in hours) of operating scenario s at each epoch t ;
- $c_{g,t}$ represents the marginal generation cost of unit g at each epoch t ; and
- $P_{g,s,t}$ is the production (in MW) of generator g , in operating scenario s at each epoch t , which is selected endogenously by the model.

The optimization is also subject to several constraints, as summarised below.

First, supply and demand must be balanced at all times (for all operating scenarios in all epochs):

$$\sum_g^{Ng} P_{g,s,t} - \sum_d^{Nd} P_{d,s,t} = 0 \quad \forall (s, t) \quad (2)$$

Where $P_{d,s,t}$ is demand at node d in operating scenario s in epoch t .

Second, power flows must respect transfer capacity of each transmission boundary, after accounting for the model's decisions to expand transmission capacity, at the assumed costs that feature in the objective function. The following equation (3) demonstrates that the capacity of transmission boundary l in epoch t is the total of existing maximum capacity and all investment selected by the model for boundary l up to epoch t .

$$|F_{l,s,t}(\mathbf{P}_{g,s,t}, \mathbf{P}_{d,s,t}, \mathbf{Y})| \leq \bar{F}_l + \sum_{p=1}^t F_{l,p}^{inv} \quad \forall (l, s, t) \quad (3)$$

Where:

- $F_{l,s,t}$ is the power flows across transmission boundary l in operating scenario s in epoch t ;
- $F_{l,s,t}$ is a function of all power injections, $\mathbf{P}_{g,s,t}$ (supply) and $\mathbf{P}_{d,s,t}$ (demand), and $\mathbf{Y}$ the “network admittance” matrix in the respective operating scenario; and
- $\bar{F}_l$ is the existing maximum transfer capacity of transmission boundary l .

Additionally, we constrain all generation and transmission capacity to operate within feasible and stable operating regions.

A.3.3. Step 2: estimating LRMCs

Although step one allows us to optimise generation dispatch and transmission investment, it does not provide the outputs required to calculate the LRMC of transmission investment imposed by changes in demand at different points on the grid. We require a second run of DTIM to calculate LRMCs.

Specifically, from the first run we take optimised net injections (optimised generation despatch, less assumed demand) at each node, and impose the constraint on DTIM that net injections at each node (and hence transmission flows) in the second run are precisely equal to the optimised level from the first run. We then let DTIM build the least-cost transmission network required to accommodate these net injections. The resulting transmission build patterns from this run are (by definition) identical to the result from the first run. The only difference is that, by imposing a pattern of nodal net injections on the model as a constraint, we can calculate the shadow cost of marginally tightening these constraints (ie. the “dual” on the constraint) on total transmission reinforcement costs.

From the shadow prices on the constraints on net injections by node, DTIM epoch and DTIM operating scenario, we can compute the LRMC of transmission expansion caused by marginal changes in demand, and analyse how these LRMCs vary over time and by node. The following detailed formulae describe precisely how we calculate the LRMCs of transmission infrastructure associated with different types of generation at different points on the system.

First, we formulate and solve an optimisation problem with the objective to minimise only the cost of transmission investment, with power injections across the system being fixed according to the results from the first step. The problem is formulated as a linear optimisation model with the following objective function:

$$\text{Min } CF_{l,s} = \sum_{s=1}^{Ns} F_{l,s} * k_l * d_l * c_{l,s} \quad (4)$$

Where:

- $CF_{l,s}$ is the power flow cost for boundary l in operating scenario s (in £);
- $F_{l,s}$ is the power flow of boundary l in scenario s (in MW);
- k_l is the unit transmission investment cost of boundary l (in £/MW), which (in broad terms) represents the annualised upfront development cost of transmission expansion, multiplied by the length of boundary l ;
- $c_{l,s}$ is a constraint flag for boundary l in scenario s , which is equal to one if the boundary is constrained in a particular operating scenario and zero if not;
- d_l is defined as follows, and is intended to represent the inverse proportion of the year that boundary l is constrained; and

$$d_l = 1 / \{ [\sum_{s=1}^{Ns} (c_{l,s} * dur_s)] / \sum_{s=1}^{Ns} dur_s \} \quad (5)$$

- dur_s is the duration of a particular scenario in hours.

Hence, the objective function in equation (4) is effectively defined such that the total capital cost of transmission infrastructure on a particular boundary in a particular hour is obtained by multiplying the unit cost of reinforcing that boundary, by the flow on that boundary, but only if that boundary is constrained during the hour in question. The equation also spreads the costs of reinforcing the boundary uniformly across those hours in the year when the boundary is constrained.

In addition to the constraint that the net injections at each node are identical to those emerging from step one, the constraints of this problem are the same as those applied in the first run (given by equations 2 and 3). As noted above, the results from this run produce exactly the same results in terms of transmission investment patterns as the run performed at the first stage. However, optimisation problem (4) enables us to calculate the Lagrange multipliers associated with nodal power balance equations, which measure the marginal impact of each power injection at each node and each scenario on network investment costs.

From these Lagrange multipliers, we can compute an annual transmission “Access Charge” for demand at each node that reflects the LRMC of transmission investment that would be marginal (eg. 1kW) changes in demand. The Annual Access Charge (for demand d at node n , in £ per annum) that reflects the LRMC of transmission investment is equal to:

$$Annual\ Access\ Charge_{d \in n} = [\sum_{s=1}^{Ns} (L_{ref,s} - L_{n,s}) * D_{n,s} * dur_s] / \sum_{s=1}^{Ns} dur_s \quad (6)$$

Where:

- $L_{n,s}$ represents the Lagrange Multiplier on the constraint on power injections at node n in operating scenario s ;
- Node ref is the reference node and corresponds to DTIM node 10;⁷⁰ and
- $D_{n,s}$ is the demand in node n in scenario s .

Note that equation (6) uses the difference between the Lagrange Multipliers at a given node (n) as compared to those at a reference node. The final step is to convert this annual access charge, which reflects LRMC, into a charge per kW of demand during the triad. This ensures comparability with current and forecast TNUoS tariffs:

⁷⁰ The definition of the reference node was selected to be consistent with the WACM 2 and status quo charging models. Selecting a different reference node would shift estimated LRMCs and transmission tariffs under both methodologies up or down, but would not change the regional spread in tariffs (e.g. the delta between Scottish and English/Welsh tariffs).

$$\text{Annual Transmission Tariff} \left(\frac{\pounds}{\text{kW}} \text{ p. a.} \right) = \text{LRMC}_d = \text{Annual Access Charge}_{d \in n} / \text{Peak}_n \quad (7)$$

Where Peak_n is the Peak demand on node n .

The final step is to compute the revenue that these charges would raise, by multiplying the Access Charges by the total charging base assumed to be present in the generation/demand background (eg. the volume of demand present on the system at a given node).

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