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Ofgem Targeted Charging Review: a consultation - RWE Response

Dear Judith,

RWE welcomes the opportunity to respond to the Ofgem consultation on a "Targeted Charging Review" (the Consultation Document published on 13th March 2017. We are responding on behalf of RWE Supply and Trading GmbH and RWE Generation plc. This is a non-confidential response.

Our detailed comments on the questions in the Consultation Document are included in Annex 1.

As you may be aware RWE raised CUSC Modification 271 (CMP271) to consider the cost reflectivity of demand transmission charges. This modification was designed to examine the wider issues associated with transmission demand charging including the demand residual and build on work undertaken on CUSC Modifications CMP264 and CMP265. CMP271 has been progressing through the CUSC process. RWE has submitted papers to support the development of CMP271. Copies of these papers are included in Annexes (2, 3 and 4) to this document.

We are disappointed that Ofgem has not recognised the work undertaken in the CMP271 workgroup in the Consultation Document. Given the scale and scope of the work envisaged in the Consultation Document, we believe that the Targeted Charging Review will cut across the CMP271 work. In the light of this, we are uncertain as to how CMP271 will progress through the CUSC process. We are concerned that work undertaken in the workgroup could prove abortive.

We believe that CMP271 provides a vehicle for the early implementation of the enduring solution that is fully compatible with the Targeted Charging Review. Therefore our preference is for CMP271 to be fully integrated into the review. We would welcome clarity from Ofgem on the way forward for CMP271 which overlap with the Targeted Charging Review.

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If you have any comments or wish to discuss the issues raised in this letter then please do not hesitate to contact me.

Yours faithfully

By email

Bill Reed
Market Development Manager.

Annex 1: RWE Response to the Consultation Document questions

Chapter 2

Question 1: Do you agree that the potential for residual charges to fall increasingly on groups of consumers who are less able to take action than others who are connected to the system, is something we should address?

We agree that the current treatment of cost recovery through residual adjustments to tariffs does impact on groups of customers less able to take action. Therefore it is appropriate that this issue should from part of the justification for undertaking a review.

Question 2: If so, why do you think, or do not think, action is needed?

We believe that action is required as a result of the significant and material increases in transmission residual charges and the distortions that they currently cause to the capacity and energy markets. We note that the impact assessment undertaken for CUSC modifications CMP264 and CMP265 illustrates the scale and extent of the potential impact in current transmission demand charges.

Question 3: We are proposing to look at residual charges in a Significant Code Review. Are there any elements of residual charges that you think should be addressed more urgently? Please say why.

While we welcome Ofgem's initiative to provide a framework for a wide ranging review of both transmission and demand charging arrangements, we are concerned that it could take some time to act on any findings. We note that as far as transmission demand charging is concerned, there are a number of CUSC modifications in progress that are considering similar areas identified in the scope of the charging review. We believe that these modifications should progress in order to provide early delivery of potential solutions to the issues raised in the review.

Chapter 4

Question 4: Are there elements of the approaches in other countries that you think could be appropriate for GB residual charges?

We believe that it is helpful to review the approach adopted in different countries to the issues associated with GB residual charges. However, the potential solutions are relatively straightforward and, based on the academic literature should be founded on a set of clear principles that are derived from non-distortive Ramsey pricing principles. The application of the resultant tariffs should be subject to appropriate safeguards for vulnerable customers.

Question 5: Are there other approaches that you know about from other jurisdictions, that you think offer relevant lessons for GB?

In developing potential solutions, Ofgem should consider the effects of adopting particular approaches to network charging on cross border trade. In particular, it seems appropriate to ensure that costs are recovered through demand charges while providing appropriate cost reflective and non-discriminatory locational signals for network users.

Chapter 5

Question 6: Do you agree that our proposed principles for assessing options for residual charges are the right ones? Please suggest any specific changes, or new principles that you think should apply.

We agree that the principles for assessing option for residual charges as set out in the Consultation Document are the right ones as a starting point for the consideration of residual tariffs.. We note in our paper on residual charges (see Annex 4) that there are a number of criteria that could be used for assessment, for example:

> "*Professor James C. Bonbright is the most widely quoted expert on the subject. In his text on public utility tariffs (Bonbright, 1961[1] and 1988[2]), he lays out ten principles for tariff design. These do not specifically focus on the pricing of distribution network services because when he was writing all utilities were vertically-integrated and distribution network services were not unbundled. Nevertheless, the ten principles noted below provide a framework within which distribution tariffs should be evaluated:*
>
> 1. *Effectiveness in yielding total revenue requirements, without encouraging undesirable over-investment or discouraging reliability and safety.*
> 2. *Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to the utility companies.*
> 3. *Stability and predictability of the tariffs themselves, with a minimum of unexpected changes that are seriously adverse to utility customers.*
> 4. *Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use.*
> 5. *Reflection of all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities).*
> 6. *Fairness in the allocation of costs among customers so that equals are treated equally.*
> 7. *Avoidance of undue discrimination so as to avoid subsidising particular customer groups.*
> 8. *Dynamic efficiency in promoting innovation and responding to changing supply–demand patterns.*
> 9. *Simplicity, certainty, convenience of payment, economy in collection, comprehensibility, public acceptability, and feasibility of application.*
> 10. *Freedom from controversies as to proper interpretation".*

Chapter 6

Question 7: In future, which of these parties should pay the transmission residual charges: generators (transmission- or distribution-connected), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

We believe that this question is not framed appropriately. The residual charge only exists to adjust marginal locational charges to ensure cost recovery. Rather we should consider first the appropriate charging base for the recovery of network owner costs. In this context the principles that underpin Ramsey pricing are important.

[1] Bonbright, James C. Principles of Public Utility Rates, Columbia University Press, 1961.
[2] Bonbright, James C., Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Second Edition, Public Utilities Reports, Inc., 1988

Ramsey pricing is based on "*charging different prices to different customer groups (or, in the case of multi-product or multi-service firms, charging different mark-ups over marginal cost on different products or services). Customers who are price inelastic are charged a higher price than those who are price elastic, and thus more of the residual costs are recovered from customers who are price inelastic than from the customers with elastic demand. This has come to be known as the inverse elasticity rule"*[3].

In considering Question 7 the key issue is whether the respective categories of user should form part of the relevant charging base for the recovery of network costs. In this context it would seem that the recovery transmission network costs should be some form of charge levied in a non-distortive manner on demand customers who will ultimately pay for the provision of a safe and secure network.

Question 8: In future, which of these parties should pay the distribution residual charges: generators (transmission- or distribution-connected.), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

The principles underpinning the recovery of transmission network costs should apply to the recovery of distribution network charges. As noted above this should be based on Ramsey pricing. Therefore it would seem that the starting point for the recovery of distribution network costs should be some form of charge levied in a non-distortive manner on demand customers who will ultimately pay for the provision of a safe and secure network.

Question 9: Do you support any of the five options we have set out for residual charges below, and why?

There are obviously several different ways of recovering network costs including capacity and commodity charges. These should be evaluated carefully as part of the review both in terms of the impact on customers and the relevant incentive properties that they create. In addition, the relative practicality of the approach should be considered carefully including the costs and timing of implementation. It would seem appropriate to consider some form of fixed price charge levied on a per meter or connection basis as a starting point for the non-distortive recovery of costs. Such charges cannot be avoided by "behind the meter" generation unless of course parties wish to no longer have a connection to the network.

Question 10: Are there other options for residual charges that you think we should consider, and why?

We do not believe that there are other options for residual charges. However, we note that we would be concerned if the cost recovery charges created incentives on parties to avoid costs or indeed to change behaviour significantly in the energy or capacity markets. This is particular concern for cost recovery charges that include commoditised elements in the tariff.

Question 11: Are there any options that you think we should rule out now? Please say why.

We do not believe that any options should be ruled out at this stage. However, we believe that the relative merits of various approaches should be assessed against clearly defined criteria.

[3] Brown T. and Faruqui A. (2014) "Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs", Report prepared by the Brattle Group for the Australian Energy Market Commission, August 2014. A link to the report can be found at http://www.brattle.com/news-and-knowledge/news/brattle-experts-prepare-report-for-the-australian-energy-market-commission-on-recovering-residual-costs-from-electricity-distribution-network-tariffs

Chapter 7

Question 12: Do you think we should do further work to analyse the potential effects of the charging arrangements for smaller EG (called 'embedded benefits')?

It is essential that the charging arrangements provide the appropriate cost reflective economic signals to users of the networks. Therefore the potential effects of the charging arrangements for smaller embedded generation, demand side activity, storage and transmission connected generation should be within scope. This should focus on ensuring that there is a level playing field for all market participants.

Question 13: Do you think changes are needed to the current charging arrangements for smaller EG, and when should any such changes be implemented?

We welcome Ofgem's decision to implement changes to the charging regime under CMP264 and CMP265. However, we note that these modification do not impact on incentives for "behind the meter" generation. We believe that it is essential that there are appropriate cost reflective incentives on all market participants and that any market distortions that arise as a consequence of network charging should be addressed as soon as practicable. This will ensure that the costs to the consumer of any market distortions are minimised.

Question 14: Of the embedded benefits listed in our table, do you think that any should be a higher or lower priority?

We believe that all of the embedded benefits listed in Table 2 should be addressed as soon as practicable. However, we note that the scale and extent of the TNUoS demand residual is such that this should clearly be a priority in terms of developing an appropriate solution.

Question 15: Do you think there are other aspects of transmission or distribution network charging which put smaller EG, or any other forms of generation or demand, at a material disadvantage?

We believe that the starting point for any consideration of the network charging regime should be the arrangements that impact exports on to the total system and imports from the total system. These exports and imports should be the basis of cost reflective charges. As far a cost recovery is concerned this should be based on Ramsey pricing.

Chapter 8

Question 16: Do you agree with our view that storage should not pay the current demand residual charge, at either transmission or distribution level?

We agree that if classed as "generation" then storage should not be double charged for use of the network. However, we think such a principle should also apply to all users classed as "generation". This would mean, for example, that power stations that are importing during triad periods are not subject to the demand residual. Such an approach would ensure that there is a level playing field for all users classed as "generation". Note that cost reflective demand charges should continue to apply for such users.

Question 17: Do you agree with our view that storage should not pay BSUoS on both demand and generation?

We agree that there is a case that if classed as “generation” then storage should not be charged for BSUoS on demand.

Question 18: Which of the BSUoS approaches describe is more likely to achieve a level playing field for storage?

We believe that if storage is classed as “generation” then it should not be subject to demand BSUoS charges.

Question 19: Do you think the changes in this chapter should be made ahead of any wider changes to residual charging that may happen in future? Do you agree with our view that these changes should be implemented by industry through the standard code change process?

We believe that any changes should apply to all market participants and should take place as soon as practicable in order to minimise customer detriment. We do not support piecemeal changes or early implementation where this does not form part of the overall enduring regime for network charges. We also believe that any change should be non-discriminatory and ensure that there is a level playing field for all network users

Chapter 9

Question 20: We would welcome your thoughts on the potential make-up of a CCG. Please refer to the potential role, structure, prioritisation criteria and assessment criteria.

We support the efficient delivery of the Target Charging Review. In this context a Charging Coordination Group could be beneficial ain ensuring effective management of the review. In particular the Group could ensure that all stakeholders are involved in the review process. The Group could also take a strategic overview so that all aspects of residual charging across different network activities (operational, transmission and distribution) are taken in to account. However, the Group would need a clear terms of reference and deliverables.

Question 21: Do you agree with our proposed delivery model, including its scope?

We are concerned that the Consultation Document does not acknowledge the modifications that are currently under consideration in CUSC Workgroups. We believe that these are an important element of the Targeted Charging Review and may facilitate industry discussion and early implementation of enduring solutions. Therefore these CUSC modifications should be incorporated into the delivery model.

Question 22: Do you agree that our proposed SCR process is most appropriate for taking forward the residual charging and other arrangements for smaller EG discussed in this document?

While we believe that it is important that there are overarching guiding principles are developed to determine the way that the network charging should develop as part of the SCR. These can then be delivered through changes to the relevant charging regimes. We are concerned that an SCR may delay rather than expedite changes. We believe that the existing CUSC modifications should be fully incorporated in the review and provide an opportunity for early implementation of solutions.

Annex 2: Paper prepared on Cost Reflectivity of Transmission Charges by RWE for discussion at the CMP271 Modification Workgroup

CMP271 – Initial thoughts on Cost Reflectivity of GB Demand Transmission Charges

Executive Summary

i. This paper considers the issues associated with the cost reflectivity of the locational tariffs derived from the CUSC charging arrangements using the Investment Cost Related Pricing Methodology (ICRP) methodology. This methodology provides relative marginal cost signals in locational demand tariffs, but by the very nature of the model these tariffs are not designed to recover transmission owner (TO) revenues.

ii. Locational tariffs could be adjusted to ensure efficient recovery of certain elements of transmission owner locational costs while overall TO cost recovery could be addressed through separate tariff arrangements (a completely separate residual tariff). Locational tariff adjustments to reflect notional locational transmission costs from the Transport Model are illustrated.

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1. Introduction

1.1. This paper provides initial thoughts on the nature of cost reflective demand transmission charges in the GB electricity market. In particular it considers the methodology for setting marginal transmission charges in Section 2, the interaction between locational tariffs and cost recovery in Section 3 and possible additional tariff components to reflect locational cost recovery in Section 4. Section 5 concludes.

1.2. These are initial thoughts on the potential issues associated with the cost reflectivity of locational transmission tariffs for the purpose of discussion at the CMP271 Working Group.

2. **Background**

2.1. The principles establishing the basis for setting GB electricity transmission tariffs are set out in Section 14 of the Connection and Use of System Code (CUSC). Tariffs are derived from a DC Load Flow model (the Transport Model) which implements the Investment Cost Related Pricing Methodology (ICRP) first introduced by National Grid in 1993/94. ICRP:

"*calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system*"[4].

2.2. The Transport Model does not recover costs from users. Rather it seeks to reflect a marginal incremental cost signal on users. The marginal locational signals that emerge from the ICRP Model provide the relative incremental costs associated with the transmission system based on the underlying simplifying assumptions (such as linear investment and standard expansion

[4] CUSC Section 14, paragraph 14.15.4

constants for build rates with outputs measured in MWkm). Annex 1 presents the process by which the 2017/18 demand transmission tariffs are derived from the model.

2.3. The basis for setting the actual transmission tariffs is set out in the CUSC as follows:

"*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. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy*."[5]

2.4. To ensure the required recovery of Transmission Owner costs the locational tariffs are adjusted. This achieved through a "residual" component of the transmission tariff. The underlying rationale for the residual is stated in the CUSC as follows:

"*In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected*"[6].

2.5. There is a body of academic literature associated with electricity transmission cost recovery which considers the issue of marginal pricing and cost recovery for transmission charging regimes. This recognises the fact that marginal cost signals from network simulation models do not recover the actual costs of owning and operating an electricity network (actual investment costs and maintenance of the transmission system). For example Perez-Arriaga et al (1995)[7] state that

"*Strict marginal network revenues (here renamed as variable charges) are clearly insufficient in practice to recover the network costs*"; and

"*In actual systems a mismatch exists between marginal network revenues and total costs, because of a number of reasons"…."They include discrepancies between static and dynamic optimal expansion plans, planning deviations and errors, the strongly discrete nature of investments, economies of scale, reliability constraints, other constrains on network investments*"

2.6. Perez-Arriaga et al (1995) conclude that

"*Experience of the authors with actual networks, including full size versions of the transmission grids of Argentina, Central America, Chile, Spain and England and Wales have shown that the percentage of cost recovery to be expected from network variable charges (i.e. strict network*

[5] Connection and Use of System Code (CUSC) Section 14, paragraph 14.14.6
[6] CUSC Section 15, paragraph 14.15.131
[7] Perez-Arriaga I.J., Rubio F.J, Puerta J.F, Arceluz J. and Marin J, "Marginal pricing of transmission services: An analysis of cost recovery", IEEE Transactions on Power Systems, Vol.10 No1, February 1995 (Perez-Arriaga et al, (1995)).

marginal revenues) does not exceed 30%. Reports from similar studies in New Zealand and South Africa appear to confirm these results"[8]

2.7. A useful summary of the issues associated with marginal pricing and cost recovery of electricity network costs is provided by Brown and Faruqui (2014) in a report prepared by the Brattle Group for the Australian Energy Market Commission[9]. This report notes that:

"While there is general agreement that marginal cost pricing works in theory, especially when it is applied to the pricing of electricity generation, there are differences of opinion about how marginal costs should be measured, how "long" is long, and how big should be the increment of demand over which the computations are carried out. The differences of opinion are particularly noticeable when it comes to the measurement of network costs, and these details become particularly important when demand is falling"[10].

2.8. Bushnell (2014) also recognised that "*allocative inefficiencies can arise when transmission prices differ substantially from the marginal costs or providing the transmission services*"[11]. In addition, Baldick et al (2011) recognised that the

"*MWkm methodology and subsequent adjustments used to obtain TNUoS charges are unlikely to bear more than the roughest relationship to incremental transmission and congestion costs resulting from a siting decision. The parameters and modelling assumptions affect the outcomes but are only indirectly connected to transmission planning*"[12].

2.9. The fact that marginal cost models (or incremental costs models) applied to electricity networks do not recover actual locational costs is hardly surprising given the nature of the charging models. This is explicitly recognised in the Transport Model since it deals with the marginal signals associated with increments of capacity at nodes on the transmission system. However, the Transport Model does identify the relative marginal costs for users in zones which are associated with investment in the transmission system.

2.10. If we recognise that the Transport Model and the associated tariffs do not in practice recovery the costs of the transmission system but provide simplified relative locational signals then we need to consider the appropriate and fair method for ensuring that the transmission owners can recover their allowed revenue. These issues are considered in the following section.

3. **GB demand transmission tariffs and cost recovery**.

3.1. This section considers the nature of GB demand tariffs in the context of the marginal cost signals and the cost recovery associated with these tariffs. As noted in Annex 1, the tariffs reflect the marginal signals on revenue recovery but do not recover the allowed revenue. These underlying revenue effects are illustrated in Table 1 for 2016/17 demand tariffs.

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[8] Perez-Arriaga I.J., Rubio F.J, Puerta J.F, Arceluz J. and Marin J, "Marginal pricing of transmission services: An analysis of cost recovery", IEEE Transactions on Power Systems, Vol.10 No1, February 1995 (Perez-Arriaga et al, (1995)).

[9] Brown T. and Faruqui A. (2014) "Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs", Report prepared by the Brattle Group for the Australian Energy Market Commission, August 2014. A link to the report can be found at http://www.brattle.com/news-and-knowledge/news/brattle-experts-prepare-report-for-the-australian-energy-market-commission-on-recovering-residual-costs-from-electricity-distribution-network-tariffs

[10] Brown and Faruqui (2014), page 4

[11] Bushnell, J. (2014), "Efficiency and Cost Recovery for Transmission network Investments" at https://www.ea.govt.nz/dmsdocument/17782

[12] Baldick, R, Bushnell J, Hobbs, B. F. and Wolak F.A., (2011), "Optimal charging arrangements for Energy Transmission: Final Report", Report prepared for and commissioned by Project Transmit, Great Britain Office of Gas and Electricity Markets.

Table 1: GB Demand Tariffs and Revenue recovery based on underlying capacity.

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Revenue (£m)	Year Round Transport Zonal Revenue (£m)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	0.923	1.73	-18.57	-16.84
2	Southern Scotland	3.109	0.07	-53.96	-53.89
3	Northern	2.267	-6.06	-13.42	-19.47
4	North West	3.854	-2.75	-7.15	-9.90
5	Yorkshire	3.566	-9.19	-0.96	-10.15
6	N Wales & Mersey	2.350	-4.27	1.87	-2.40
7	East Midlands	4.360	-9.29	9.62	0.33
8	Midlands	4.125	-5.82	12.60	6.78
9	Eastern	6.036	6.29	4.60	10.89
10	South Wales	1.657	-10.25	6.50	-3.75
11	South East	3.711	14.32	3.22	17.53
12	London	4.112	20.74	8.68	29.43
13	Southern	5.179	8.70	20.27	28.97
14	South Western	2.436	-2.27	12.37	10.09
		47.684	**1.96**	**-14.33**	**-12.37**

3.2. The locational elements of the GB demand tariffs are adjusted by a residual component to ensure that the GB transmission owners' recovery the revenue allowed under the price control regime. This is achieved by adding the locational components of the tariff together and then adding a residual component to ensure cost recovery across the relevant charging base.

3.3. While the current approach preserves the relative locational signals (based on the incremental MW) the additional of the residual has a material impact on the absolute locational signals. This effect is illustrated in Table 2 for half hourly tariffs.

Table 2: Effect of the residual on the locational signals for 2017/18 demand half-hourly tariffs

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Final Locational Tariff (£/kW)	Residual Tariff (£/kW)	Final Zonal Tariff (£/kW)
1	Northern Scotland	923.39	-18.24	47.98	29.75
2	Southern Scotland	3,109.18	-17.33	47.98	30.65
3	Northern	2,266.99	-8.59	47.98	39.39
4	North West	3,853.96	-2.57	47.98	45.42
5	Yorkshire	3,565.78	-2.85	47.98	45.14
6	N Wales & Mersey	2,349.89	-1.02	47.98	46.96
7	East Midlands	4,360.13	0.08	47.98	48.06
8	Midlands	4,124.58	1.64	47.98	49.63
9	Eastern	6,035.90	1.80	47.98	49.79
10	South Wales	1,656.54	-2.26	47.98	45.72
11	South East	3,711.20	4.72	47.98	52.71
12	London	4,111.70	7.16	47.98	55.14
13	Southern	5,179.46	5.59	47.98	53.58
14	South Western	2,435.66	4.14	47.98	52.13
		47,684.35			

3.4. As is clear from Table 2 the addition of the residual to the locational tariffs has a significant and material impact on the locational signals in the final tariffs. For example, the negative marginal signal in Northern Scotland is replaced by a positive signal. In other words the raw output from the Transport Model and the locational tariff suggests that the marginal costs of an increment of demand in Northern Scotland is to reduce investment in the transmission system (i.e. it is a benefit to the increment of demand). However the final tariff could be interpreted as increasing transmission investment (i.e. it is a cost levied on the increment of demand).

3.5. The non-half hourly charging base has a further effect on the efficiency of the locational signals. For example, the locational tariff suggests that a decrease in demand in Northern Scotland would increase transmission investment (based on the marginal investment signals as a negative embedded benefit). However, the final tariffs could be interpreted as reducing transmission investment (since the final tariff is positive rather than negative and a positive embedded benefit).

3.6. CUSC Modification Proposal CMP271 seeks to address the effects of the residual on the locational marginal signals by considering the cost reflective elements of the GB demand tariffs separately from the cost recovery elements. In particular it is designed to address the effects of inefficient incentives created as a result of the Triad charges arrangements whereby certain users can avoid paying for any costs associated with the transmission system (including locational, fixed and capital costs).

3.7. However, when considering the locational component of the tariff it is worth examining whether there are some elements of cost recovery that should be applied to the locational tariffs. In essence this requires the application of an additional charge similar to the residual adjustment to the locational component of the tariff.

3.8. There have been a number of suggestions that could form the basis for determining adjustments to the locational charge. The CUSC Section 14.14.6 refers to the relevant costs as

"*These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy*"

3.9. There are a number of alternative approaches towards determining the “relevant costs” of the transmission system. These include:

- The costs associated with the underlying MWkm in the Transport Models for each background (peak and year round); or
- The avoidable costs of the transmission system (locational, fixed and capital costs) as implied under the current Triad methodology for half hourly customers (maintain the status quo); or
- Some element of avoidable long run costs as suggested by Cornwall Consulting; or
- Avoidable connection costs as suggested in some of the alternative proposals under CMP264 and CMP265 (see for example the Uniper mods); or
- Some element of “locational costs” associated with transmission system costs (as seems to be implied by the Ofgem review of fixed and sunk cost recovery separately from locational cost recovery)

3.10. There are also suggestions elsewhere that transmission prices should be based on some form of “*beneficiaries pay*” option, perhaps reflecting somewhat “deeper” charges for wider system investment (this is the basis for the review of the New Zealand electricity transmission charging methodologies”[13]) or some form of “*locational marginal pricing”* (see for example Baldick et al (2011)[14]). However, such an approach would be a radical departure from the existing charging methodology and beyond the scope of CMP271. Therefore these approaches are not considered further here.

3.11. Clearly the underlying ICRP model provides marginal cost signals and any additional charge should seek to minimise potential distortions. The following section considers the potential “avoidable” costs that could be used as a basis for adjusting the locational component of the tariff.

4. “Avoidable costs” and locational transmission tariffs

4.1. The overriding issues associated with any adjustment to the marginal cost signal associated with the locational tariffs derived from the Transport Model is the minimisation of any potential distortions which may occur. Any adjustment must:

- Preserve the relative locational effects of the tariffs in the zones;
- Provide fair, equitable and efficient locational signals; and
- Relate to underlying costs with a clear rationale for levying the costs.

4.2. A tariff adjustment identified essentially requires an additional tariff component to be added as a uniform adjustment to the locational tariff.

4.3. A starting point for such an adjustment could be the assumption that some elements of transmission costs are locational and some that are non-locational. For example “fixed” or “sunk” costs could be considered non locational. This category could include costs such as pensions, financing costs and administrative costs. Locational costs could include those elements of transmission costs that are determined by the location of generation and demand.

[13] Electricity Authority (2014), Transmission pricing methodology review: beneficiary pays options working paper”, prepared by the New Zealand Electricity Authority, at *https://www.ea.govt.nz/dmsdocument/17782*
[14] Baldick, R, Bushnell J, Hobbs, B. F. and Wolak F.A., (2011), “Optimal charging arrangements for Energy Transmission: Final Report”, Report prepared for and commissioned by Project Transmit, Great Britain Office of Gas and Electricity Markets.

This category could include the costs associated with the towers, cables and substations. It should be noted that the charging methodology already recognises some costs as "connection costs" and "local" costs. Such local costs are not considered further in this paper.

4.4. The current ICRP Transport Model allows a notional level of underlying locational costs to be identified. This is in the form of the transmission circuits that are designated as either peak security or rear round depending upon the background resulting in the highest flow. The Transport Model calculates the resultant total peak security MWkm and total year round MWkm using the relevant circuit expansion factors as appropriate[15]. This is the baseline network for calculating the incremental load flows.

4.5. On the basis of the total peak security MWkm and total year sound MWkm we can apply the Transport Model expansion factor and the security factor in order to estimate the notional value of the total system. This is illustrated in Table 3.

Table 3: National value of the Total System in 2017/18 based on the Transport Model and net MWkm

Background	Background Cost (MWkm)	Background Cost %	Expansion Constant (£/MWkm)	Locational Security Factor	Background Cost (£m)
Peak Security	5,340,068	47.52%	13.575354	1.80	130.488
Year Round	5,897,125	52.48%	13.575354	1.80	144.100
	11,237,193.00				**274.59**

	Peak Security Unadjusted Net Zonal Wtd Marginal (km)	Year Round Unadjusted Net Zonal Wtd Marginal (km)	Total Unadjusted Net Zonal Wtd Marginal (km)	Peak Security Unadjusted Net Zonal Wtd Marginal (%)	Year Round Unadjusted Net Zonal Wtd Marginal (k%)
Demand	201.27	932.92	1,134.19	1.5%	7.1%
Generation	1,362.79	10,704.63	12,067.42	10.3%	81.1%
	1,564.06	11,637.55	13,201.61	11.8%	88.2%

4.6. There are a number of ways of assigning the notional cost of the transmission system into locational charges. This could be on a zonal basis using the weighting for generation and demand, a split between generation and demand (27:73 for example), weighted by MWkm (see Table 3 above) or 100% to demand.

4.7. For the purpose of this analysis it is assumed that the notional transmission cost is assigned in proportion to the MWkm in each background (Peak Security: 47.52%; Year Round: 52.48%) and divided on a 27/73 basis to generation and demand (Table 4). This provides the basis for an adjustment to the locational demand tariffs.

Table 4. Notional Cost recovery of background costs

Background	Background Cost %	Background Cost (£m)	Generation Proportion (%)	Demand Proportion (%)	Generation Background Cost (£m)	Demand Background Cost (£m)
Peak Security	47.52%	130.488	27%	73%	35.232	95.256
Year Round	52.48%	144.100	27%	73%	38.907	105.193
		274.59			**74.14**	**200.45**

[15] CUSC Section 14 paragraph 14.15.25

4.8. Applying the background costs to the total demand capacity leads to a uniform adjustment to the locational tariffs in each zone as illustrated in Table 5.

Table 5: Locational Tariffs adjusted to reflect the uniform adjustment

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Tariff (£/kW)	Zonal Tariff Adjuster (£/kW)	Adjusted Zonal Revenue (£m)	Effective Peak Security Zonal Tariff (£/kW)
1	Northern Scotland	0.923	1.87	2.00	1.84	3.87
2	Southern Scotland	3.109	0.02	2.00	6.21	2.02
3	Northern	2.267	-2.67	2.00	4.53	-0.67
4	North West	3.854	-0.71	2.00	7.70	1.28
5	Yorkshire	3.566	-2.58	2.00	7.12	-0.58
6	N Wales & Mersey	2.350	-1.82	2.00	4.69	0.18
7	East Midlands	4.360	-2.13	2.00	8.71	-0.13
8	Midlands	4.125	-1.41	2.00	8.24	0.59
9	Eastern	6.036	1.04	2.00	12.06	3.04
10	South Wales	1.657	-6.19	2.00	3.31	-4.19
11	South East	3.711	3.86	2.00	7.41	5.86
12	London	4.112	5.05	2.00	8.21	7.04
13	Southern	5.179	1.68	2.00	10.35	3.68
14	South Western	2.436	-0.93	2.00	4.87	1.06
		47.684			95.256	
Zone	**Zone Name**	**Total Demand Charge Base: Triad Demand (GW)**	**Year Round Transport Zonal Tariff (£/kW)**	**Zonal Tariff Adjuster (£/kW)**	**Adjusted Zonal Revenue (£m)**	**Effective Year Round Zonal Tariff (£/kW)**
1	Northern Scotland	0.923	-20.11	2.21	2.04	-17.90
2	Southern Scotland	3.109	-17.36	2.21	6.86	-15.15
3	Northern	2.267	-5.92	2.21	5.00	-3.71
4	North West	3.854	-1.85	2.21	8.50	0.35
5	Yorkshire	3.566	-0.27	2.21	7.87	1.94
6	N Wales & Mersey	2.350	0.79	2.21	5.18	3.00
7	East Midlands	4.360	2.21	2.21	9.62	4.41
8	Midlands	4.125	3.05	2.21	9.10	5.26
9	Eastern	6.036	0.76	2.21	13.32	2.97
10	South Wales	1.657	3.92	2.21	3.65	6.13
11	South East	3.711	0.87	2.21	8.19	3.07
12	London	4.112	2.11	2.21	9.07	4.32
13	Southern	5.179	3.91	2.21	11.43	6.12
14	South Western	2.436	5.08	2.21	5.37	7.28
		47.684			105.193	

4.9. The effect of notional locational transmission cost recovery in the locational zonal tariffs is to uplift Peak Security tariffs by £2/kW and Year Round Tariffs by £2.21. Note that the actual recovery of costs is also influenced by the charging base to which the demand tariffs are applied (currently the half hourly Triad capacity (£/kW) and non-half hourly consumption in the 16.00 to 19.00 periods across the year (in £/kWh) which is not assessed here.

4.10. This section has provided an example of a possible adjustment to the zonal tariffs to reflect notional locational revenue cost recovery. The approach identified here could form the basis of any tariff adjustment to reflect recovery of "locational revenue". As noted above there may be alternative approaches to calculating the avoidable costs as noted above (e.g. avoidable connection costs) but the tariff adjustment approach represents a practical means for incorporating cost recovery alongside locational marginal tariffs.

5. Negative and Positive Marginal MWkm and Locational tariffs

5.1. As has been noted elsewhere[16] the negative and positive marginal MWkm are simply an artefact of the Transport Model and assumptions about the load flow on the transmission system. In particular the assumed nature of the slack node influences whether the marginal MWkm are negative or positive. The current assumption in the transport model is that an injective of 1MW at a generation node is absorbed at all demand nodes on the transmission system. This result in a set of outputs that reflect the relative impact of incremental MWkm for zones across the GB transmission system.

5.2. Since the Transport Model outputs provide both negative and positive marginal signals in terms of the MWkm. When the expansion factor and the security factor are applied to these tariffs, the resultant locational tariffs are both positive and negative. With regard to the demand tariffs this creates the following locational signals in the demand tariffs in relation to the Transport Model:

- Negative locational peak tariffs could create an incentive to increase demand at the peak periods (increase peak capacity);
- Positive locational peak tariffs could create an incentive to reduce demand at the peak (decrease peak capacity);
- Negative year round signals could create an incentive to increase demand year round (increase year round capacity)
- Positive year round signals could create an incentive to decrease demand year round (decrease year round capacity).

5.3. The key question for the cost reflectivity of the locational signals is whether it is appropriate to create and apply the locational signals in the tariffs as described above. Given the incentive properties, it is appropriate to consider whether ii is a correct incentive to increase or reduce demand in certain zones during peak periods or year round given the wider impact of such incentives on for example, transmission investment, generation investment and security of supply from short term operation effects.

5.4. In addition, the nature of locational signals from the Transport Model is influenced by the charging base. Currently the half hour/non half hourly split creates different signals in relation to different users on the transmission system. These issues should be considered further under the cost recovery work stream under CMP271.

5.5. However, it is important to preserve the **relative** locational signals derived from the MWkm rather than the **absolute** level of these signals (which simply reflect model assumptions). Consequently if it were determined that it is inappropriate to provide negative peak demand signals in the locational tariffs then the resultant tariffs should be adjusted so that the lowest zonal tariff was set to zero and the relative marginal signals preserved. This is illustrated in Table 6 and Table 7.

[16] See for example the work by NERA for the ADE as presented at the CMP271 workgroup

Table 6: Peak Security Tariffs for 2017/18 rebased to avoid negative charges

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Tariff (£/kW)	Peak Security Tariff Adjuster £/KW	Effective Peak Security Zonal Tariff (£/kW)	Adjusted Zonal Revenue (£m)
1	Northern Scotland	0.923	1.87	-6.19	8.06	7.44
2	Southern Scotland	3.109	0.02	-6.19	6.21	19.30
3	Northern	2.267	-2.67	-6.19	3.51	7.97
4	North West	3.854	-0.71	-6.19	5.47	21.09
5	Yorkshire	3.566	-2.58	-6.19	3.61	12.87
6	N Wales & Mersey	2.350	-1.82	-6.19	4.37	10.27
7	East Midlands	4.360	-2.13	-6.19	4.06	17.68
8	Midlands	4.125	-1.41	-6.19	4.78	19.70
9	Eastern	6.036	1.04	-6.19	7.23	43.62
10	South Wales	1.657	-6.19	-6.19	0.00	0.00
11	South East	3.711	3.86	-6.19	10.04	37.27
12	London	4.112	5.05	-6.19	11.23	46.18
13	Southern	5.179	1.68	-6.19	7.87	40.74
14	South Western	2.436	-0.93	-6.19	5.25	12.79
		47.684				296.912

Table 7: Peak Security Tariffs for 2017/18 rebased to avoid negative charges

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Year Round Transport Zonal Tariff (£/kW)	Year Round Tariff Adjuster £/KW	Effective Year Round Zonal Tariff (£/kW)	Adjusted Zonal Revenue (£m)
1	Northern Scotland	0.923	-20.11	-20.11	0.00	0.00
2	Southern Scotland	3.109	-17.36	-20.11	2.75	8.56
3	Northern	2.267	-5.92	-20.11	14.19	32.17
4	North West	3.854	-1.85	-20.11	18.26	70.36
5	Yorkshire	3.566	-0.27	-20.11	19.84	70.74
6	N Wales & Mersey	2.350	0.79	-20.11	20.90	49.12
7	East Midlands	4.360	2.21	-20.11	22.32	97.30
8	Midlands	4.125	3.05	-20.11	23.16	95.54
9	Eastern	6.036	0.76	-20.11	20.87	125.98
10	South Wales	1.657	3.92	-20.11	24.03	39.81
11	South East	3.711	0.87	-20.11	20.98	77.85
12	London	4.112	2.11	-20.11	22.22	91.37
13	Southern	5.179	3.91	-20.11	24.02	124.42
14	South Western	2.436	5.08	-20.11	25.19	61.34
		47.684				944.565

5.6. It should be noted that any rebasing of the demand locational tariffs to avoid negative charges and preserve relative locational signals has implications for cost recovery as illustrated in Table 6 and 7 Note that the data in Tables 6 and 7 is based on a capacity charging base in each charging zone (consistent with the Transport Model inputs).

6. Conclusions

6.1. This paper has considered the issues associated with the cost reflectivity of the locational tariffs derived from the ICRP methodology and the CUSC charging arrangements. It is clear that the methodology provides important relative marginal cost signals in the locational tariffs, but by the very nature of the model these tariffs are not designed to recover transmission owner revenues.

6.2. Locational tariffs could be adjusted to ensure efficient recovery of certain elements of transmission owner locational costs. This is illustrated through tariff adjustments to reflect notional locational transmission costs from the Transport Model.

6.3. Demand locational tariffs derived from the model are impacted by the current methodology used to ensure transmission owner cost recovery. This has a significant and material impact on locational signals. Treating the residual component of the tariff as a separate charge ensures that efficient locational signals can be considered separately from cost recovery of transmission owner allowed revenues.

6.4. Further work is clearly required to consider the nature of the elements of transmission owner costs that should be incorporated into the locational tariffs. This should consider the effects of such adjustments on the locational signals provided to users connected to the transmission system

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Annex A: Investment Cost Related Pricing (ICRP) methodology and demand tariffs

Introduction

A.1. The Investment Cost Related Pricing (ICRP) methodology introduced in 1993/94 is used to calculate transmission charges in Great Britain (GB). The charges are based on deriving the marginal investment cost of additional demand or generation using a DC Load Flow model (the Transport Model).

The Transport Model

A.2. The ICRP methodology considers the effects of an incremental MW at each node on the transmission system. This is achieved through increasing generation and demand at each node and identifying the incremental effects. The impact of the marginal MW is measured in "MWkm" (which can be positive and negative) for each node the Transport Model.

A.3. The marginal effects are categorised as related to either a "Peak Security" or a "Year Round" background, which reflect drivers for investment in transmission assets as set out in the National Electricity Transmission System (NETS) System Quality and Security Standard (SQSS).

A.4. The SQSS makes certain assumptions about the generation and demand capacity of each node on the system which are used in the Transport Model:

- The Peak Security scales "conventional generation" to meet ACS (average cold spell) peak demand (there is no contribution from "intermittent" generation capacity"); and
- The Year Round background assumes fixed scaling factors for "intermittent" generation and scales conventional generation to meet ensure that ACS peak demand is satisfied.

Transport Model Outputs

A.5. The output from the Transport Model is marginal MWkm grouped together into GSP Groups for demand and generation Zones for each background weighted by the relevant demand or generation capacity. Generation zones are based on grouping nodes that are electrically and geographically proximate using a fixed differential (+/-1.00kW) for the wider marginal costs.

A.6. The zonal tariffs are derived by multiplying the marginal MWkm by an "expansion constant" which reflects the assumed incremental costs per MW of transmission investment and a "security factor" that reflects the requirement network resilience (using the N-1 standard). The incremental MW and the derived £/kW tariffs for demand in 2017/18 are illustrated in Table A1.

Table A1: Demand tariffs in 2017/18[17]

Derivation of Zonal Demand HH Tariffs			Peak Security			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Peak Security Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	-76.64	-1,040.45	-1,872.81	1.87
2	Southern Scotland	3.109	-0.92	-12.52	-22.54	0.02
3	Northern	2.267	109.32	1,484.00	2,671.21	-2.67
4	North West	3.854	29.20	396.42	713.56	-0.71
5	Yorkshire	3.566	105.43	1,431.27	2,576.29	-2.58
6	N Wales & Mersey	2.350	74.35	1,009.29	1,816.72	-1.82
7	East Midlands	4.360	87.18	1,183.56	2,130.41	-2.13
8	Midlands	4.125	57.72	783.51	1,410.31	-1.41
9	Eastern	6.036	-42.63	-578.77	-1,041.79	1.04
10	South Wales	1.657	253.13	3,436.39	6,185.50	-6.19
11	South East	3.711	-157.88	-2,143.29	-3,857.92	3.86
12	London	4.112	-206.46	-2,802.83	-5,045.10	5.05
13	Southern	5.179	-68.74	-933.11	-1,679.61	1.68
14	South Western	2.436	38.22	518.83	933.90	-0.93
		47.684				

Derivation of Zonal Demand HH Tariffs			Year Round			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Year Round Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Year Round Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	822.95	11,171.82	20,109.28	-20.11
2	Southern Scotland	3.109	710.26	9,642.03	17,355.65	-17.36
3	Northern	2.267	242.23	3,288.41	5,919.15	-5.92
4	North West	3.854	75.87	1,029.97	1,853.94	-1.85
5	Yorkshire	3.566	11.04	149.88	269.78	-0.27
6	N Wales & Mersey	2.350	-32.53	-441.54	-794.77	0.79
7	East Midlands	4.360	-90.30	-1,225.84	-2,206.52	2.21
8	Midlands	4.125	-125.02	-1,697.14	-3,054.86	3.05
9	Eastern	6.036	-31.20	-423.55	-762.40	0.76
10	South Wales	1.657	-160.60	-2,180.14	-3,924.24	3.92
11	South East	3.711	-35.48	-481.64	-866.95	0.87
12	London	4.112	-86.43	-1,173.33	-2,112.00	2.11
13	Southern	5.179	-160.13	-2,173.79	-3,912.82	3.91
14	South Western	2.436	-207.76	-2,820.41	-5,076.74	5.08
		47.684	932.92			

A.7. Based on the demand capacity and the transport tariffs an initial estimate of the revenue recovery through the locational tariffs can be derived from the model for each background. This is illustrated in Table A2 for the 2017/18 Demand Tariffs.

[17] The "Total Demand Charge Base: Triad Demand" is the peak demand on the transmission system for the purpose of setting tariffs

Table A2: Notional revenue recovery from demand locational tariffs using demand capacities

Derivation of Zonal Demand HH Tariffs				
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Revenue (£m)	Year Round Transport Zonal Revenue (£m)
1	Northern Scotland	0.923	1.73	-18.57
2	Southern Scotland	3.109	0.07	-53.96
3	Northern	2.267	-6.06	-13.42
4	North West	3.854	-2.75	-7.15
5	Yorkshire	3.566	-9.19	-0.96
6	N Wales & Mersey	2.350	-4.27	1.87
7	East Midlands	4.360	-9.29	9.62
8	Midlands	4.125	-5.82	12.60
9	Eastern	6.036	6.29	4.60
10	South Wales	1.657	-10.25	6.50
11	South East	3.711	14.32	3.22
12	London	4.112	20.74	8.68
13	Southern	5.179	8.70	20.27
14	South Western	2.436	-2.27	12.37
		47.684	**1.96**	**-14.33**

Charging Methodology

A.8. For the purpose of applying the tariffs to Supplier demand in the charging methodology under the CUSC, the zonal demand locational tariffs in the model are combined for each zone (peak and year round locational tariffs are added together). The effect of the combined locational tariff using the demand capacity methodology on revenue recovery is illustrated in Table A3.

Table A3: Notional zonal demand revenue recovery in 2017/18 (excluding the residual component of the tariff and based on the current charging methodology)

Derivation of Capped Zonal Demand NHH Tariffs			Final HH Demand Tariffs	
Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	923.39	-18.24	-16.84
2	Southern Scotlan	3,109.18	-17.33	-53.89
3	Northern	2,266.99	-8.59	-19.47
4	North West	3,853.96	-2.57	-9.90
5	Yorkshire	3,565.78	-2.85	-10.15
6	N Wales & Merse	2,349.89	-1.02	-2.40
7	East Midlands	4,360.13	0.08	0.33
8	Midlands	4,124.58	1.64	6.78
9	Eastern	6,035.90	1.80	10.89
10	South Wales	1,656.54	-2.26	-3.75
11	South East	3,711.20	4.72	17.53
12	London	4,111.70	7.16	29.43
13	Southern	5,179.46	5.59	28.97
14	South Western	2,435.66	4.14	10.09
		47,684.35		**-12.37**

A.9. The final stage in the charging methodology is to adjust the locational charges to ensure overall cost recovery. This is through a “residual” adjustment to the tariffs (Table A4).

Table A4: Demand locational Tariffs and Residual Adjustment

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Final Zonal Revenue Recovery (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)	Final Zonal Tariff (£/kW)
1	Northern Scotla	0.923	- 18.24	47.98	44.31	29.75
2	Southern Scotla	3.109	- 17.33	47.98	149.19	30.65
3	Northern	2.267	- 8.59	47.98	108.78	39.39
4	North West	3.854	- 2.57	47.98	184.93	45.42
5	Yorkshire	3.566	- 2.85	47.98	171.10	45.14
6	N Wales & Mer	2.350	- 1.02	47.98	112.76	46.96
7	East Midlands	4.360	0.08	47.98	209.22	48.06
8	Midlands	4.125	1.64	47.98	197.92	49.63
9	Eastern	6.036	1.80	47.98	289.63	49.79
10	South Wales	1.657	- 2.26	47.98	79.49	45.72
11	South East	3.711	4.72	47.98	178.08	52.71
12	London	4.112	7.16	47.98	197.30	55.14
13	Southern	5.179	5.59	47.98	248.53	53.58
14	South Western	2.436	4.14	47.98	116.87	52.13
		47.684			**2,288.12**	

A.10. The tariffs are then applied to half hourly demand based on a "half hourly" p/kW tariff applied to system peak demand capacity measured across the three half hours in the winter separated by 10 days (the Triad demand) and a "non-half hour" p/KWh tariff based on supplier demand from 16:00 to 19:00 hrs every day over the financial year. (Table A5).

Table A5: Demand tariffs and revenue recovery 2017/18.

Derivation of Capped Zonal Demand NHH Tariffs

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Chargeable HH Zonal Triad Demand (MW)	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share (%)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	923.39	- 668.025	-19.87	1,591.42	47.34	0.752253	3%	6.29
2	Southern Scotland	3,109.18	641.726	19.67	2,467.45	75.63	1.763499	7%	4.29
3	Northern	2,266.99	314.289	12.38	1,952.71	76.93	1.286790	5%	5.98
4	North West	3,853.96	1,174.622	53.35	2,679.33	121.69	2.063560	8%	5.90
5	Yorkshire	3,565.78	1,106.638	49.95	2,459.14	111.00	1.850096	7%	6.00
6	N Wales & Mersey	2,349.89	519.724	24.41	1,830.17	85.95	1.295523	5%	6.63
7	East Midlands	4,360.13	1,456.313	69.99	2,903.82	139.56	2.226530	9%	6.27
8	Midlands	4,124.58	1,400.271	69.49	2,724.31	135.21	2.097776	8%	6.45
9	Eastern	6,035.90	1,472.861	73.33	4,563.04	227.19	3.189258	13%	7.12
10	South Wales	1,656.54	554.199	25.34	1,102.34	50.40	0.870233	3%	5.79
11	South East	3,711.20	870.404	45.88	2,840.79	149.74	1.995657	8%	7.50
12	London	4,111.70	2,194.260	121.00	1,917.44	105.73	1.927899	8%	5.48
13	Southern	5,179.46	1,649.598	88.38	3,529.86	189.12	2.675603	11%	7.07
14	South Western	2,435.66	540.175	28.16	1,895.49	98.81	1.318527	5%	7.49
		47,684.35	**13,227.05**	**661.46**	**34,457.30**	**1,614.29**	**25.313203**		

Annex 3: Paper prepared on Cost Recovery of Transmission Charges by RWE for discussion at the CMP271 Modification Workgroup

CMP271 – Initial thoughts on Cost Recovery of GB Demand Transmission Charges

Executive Summary

I. This paper provides initial thoughts on the relevant charging base for the cost recovery associated with locational GB demand tariffs. The Transport Model enables peak and year round tariffs to be derived from ACS Peak Demand (expressed in £/kW). This should be the starting point for consideration of the charging base since a capacity based charge will most closely represent the Transport Model, which in itself reflects the Security Standard.

II. The peak background in the Security Standard is designed to represent investment in the transmission system that arise as a result of peak conditions on the transmission system while the year round background is designed to represent investment in the transmission system that arises as a result of year round conditions on the transmission system. In this context it seems sensible for cost recovery under the Peak Tariff to be based on a "peak" charging base using the current Triad arrangements (in £/kW).

III. However, there are a number of options for the year round charging base including supplier consumption across the year (expressed in £/kWh tariffs, the P271 proposal) or a variant of the current charging base such as 1600 to 19:00 Supplier demand (expressed in £/kWh) or the current non half hourly demand charging base expressed in £/kWh). However, it does not seem appropriate for locational tariffs to be based on an arbitrary split between half-hour and non-half hour metering (the current arrangements)

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1. Introduction

1.1. This paper provides initial thoughts on the relevant charging base for the cost recovery associated with locational GB demand tariffs for the purpose of discussion at the CMP271 Working Group.

1.2. Section 2 presents the background to the current charging base and Section 3 considers the effects of the charging base on the peak and year round locational tariffs. Section 4 presents alternative options for the approach towards an enduring charging base for the locational tariffs. Section 5 concludes.

2. Background

2.1. The principles establishing GB electricity demand transmission tariffs are set out in Section 14 of the Connection and Use of System Code (CUSC) (see Annex 1). Tariffs are derived from a DC load flow model (Transport Model) based on the capacity in each zone. The rationale for setting the transmission tariffs is set out in CUSC Section 14.14.6 which states that:

"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. These costs are primarily

defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy".

2.2. Section 14.17.9 sets out the basis for demand charges. It applies a combined (peak and year round) locational tariff and the demand residual to the relevant charging base, which in the case of suppliers is either half hourly or non-half hourly demand. The arrangement is explained as follows:

14.17.9 A Supplier BM Unit charges will be the sum of its energy and demand liabilities where:

- *The Chargeable Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered demand during the Triad (and the £/kW tariff), and*

- *The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).*

2.3. In addition to supplier charges, the CUSC explains that certain users (exemptible generators with BMUs and BEGAs) are also liable for demand charges. This class of user can therefore receive Triad benefits directly if they reduce overall demand in the Triad period in the relevant GSP Group.

2.4. There are a number of observations about the current charging methodology in relation to cost recovery:

- The Transport Model is based on the ACS peak demand at each node translated to a zonal capacity for each GSP group. However the CUSC introduces an arbitrary split for supplier demand based on half-hourly and non-half hourly meters;,
- The charging methodology introduces a distinction between capacity charges for half hourly customers and energy charges for non-half hourly customers;
- The differentiation between half hourly and non-half hourly consumption; classes does not reflect the underlying investment conditions in the Security Standard; and
- Demand locational tariffs are combined by adding together the peak and year round locational tariffs and adjusted by the residual to ensure overall Transmission Owner revenue recovery. Although the tariffs preserve relative locational signals there are issues associated with the absolute level of the tariffs, particularly in relation to the avoidable cost signals for distribution connected generators.

2.5. The CUSC sets out the underlying "further" objectives for charging as follows:

"14.14.11 *In setting and reviewing these charges The Company has a number of further objectives. These are to:*

- *offer clarity of principles and transparency of the methodology;*
- *inform existing Users and potential new entrants with accurate and stable cost messages;*
- *charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and*
- *be implementable within practical cost parameters and time-scales*".

2.6. The current basis of Supplier charges must be assessed in the context of these criteria. While the current charges are transparent, and practical to implement the key issue is whether they provide ”*accurate and stable cost messages*” or whether they “*promote the optimal use of and investment in the transmission system”.*

2.7. This paper considers the effects of the demand charging base on the locational elements of the tariff. The issues associated with the residual and its effects on demand charges are considered elsewhere (see CMP271 work stream 3).

3. The effect of the demand charging base on locational tariffs

3.1. The underlying Transport Model is based on ACS peak demand for each node under the peak security and the year round backgrounds. However, the locational tariffs are currently combined to form the locational tariff and a residual component is added to ensure revenue recovery. This tariff is then then applied to half hour peak demand capacity measured at the Triad and supplier demand in the 16:00 -19:00 period across the year.

3.2. The demand charging base in the charging methodology is significantly different to basis on which the locational tariffs are derived under the Transport Model. This impacts on the absolute level of the marginal signals derived from the transport model. It addition the final tariff arrangements create differential incentives in relation to certain classes of consumer. This section considers that effects in relation to half hour and non-half our demand

Half Hourly demand

3.3. The Triad arrangements for half hourly demand are consistent with the use of the ACS peak demand background in the Transport Model. However its application to half hour demand exclusively is not.

3.4. The rationale for the current approach towards half-hourly charging is not set out in the current charging methodology. However, there may be a number of reasons for the use of a half-hourly demand charging base:

- It may reflect the assumption that half hourly customers can respond to a peak related charge, and thereby reduce peak related transmission investment; or
- It may be related to legacy arrangements that allowed certain large industrial customers metered on a half hourly basis relief from certain transmission charges; or
- It may be based on some historic assessment of avoidable transmission cost for half hourly customers.

3.5. Whatever the rationale for the half-hourly charging base, it is clear the scale and extent of the avoidable costs in the current tariffs for this class of customer is significant and material. Furthermore, transmission charge forecasts suggest that in the absence of any regulatory intervention that the level of forecast avoidable costs is set to grow significantly. This growth has the potential to distort both the energy and capacity market by creating what may be described as excessive incentives to connect to distribution networks.

Non Half Hourly demand

3.6. The rationale for the non-half hourly charging base it not set out in the CUSC. The methodology is weighted to the relatively higher demand periods across the year (16:00 – 19:00). This may well reflect that it is appropriate to levy these tariffs from some notion of within day peak demand.

3.7. It is also worth noting that the non-half hourly tariff is a commodity based charge (p/kWh) and is only indirectly related to the capacity based locational tariff. IN other words the final tariff is in the form of an energy charge related to consumption (£/kWh) rather than a capacity charge.

The impact of the Demand Charging base

3.8. The effect of the charging base on user incentives should not be under estimated. It has the following effects:

- It provides a strong incentive for certain half hour users to avoid demand transmission charges at the peak;
- It recovers mush of the cost from inflexible half hourly and non-half hour users that are unable to respond to the signals;
- The transfer of customers from non-half hourly to half hourly impacts on cost recovery as in practice only half hourly customers are capable of avoiding the costs (the 16:00 to 19:00 charging base provides a weak signal to avoid costs); and
- The Triad approach may overly reward peak avoidance, resulting in flattening of peak demand and enhancing unpredictability of demand.

3.9. This section has attempted to clarify the basis for the current charging base with respect to locational tariffs. Staring from the current capacity based locational tariffs, the charging methodology translates the actual tariffs into separate charging bases for half hourly and non-half hourly. The following section considers potential alternative approaches to the charging base for demand locational tariffs and associated cost recovery.

4. The basis for the charging base for demand transmission tariffs

4.1. This section considers potential approaches towards the demand charging base for the locational tariffs and any associated cost recovery under modification proposal CMP271. It is not intended to provide a definitive approach by considers a number of potential options.

4.2. However, it does not include the current charging arrangements (combined locational tariffs and distinct half hour and non-half hour charging base) as a sustainable approach. There are a number of reasons for this:

- There is no clear rationale for combining locational charges and dividing the charging base into half hourly or no half hourly charges except for administrative simplicity;
- The use of half hourly and non-half hourly charging bases has incentive properties that may be inefficient in terms of transmission investment; and
- The arrangements are unsustainable as customers migrate from non-half hour to half hourly through the introduction of smart meters.

4.3. The following sections discuss potential options for the charging base. These build on the assumption that there will be two locational tariffs (peak and year round) and some element of cost recovery associated with them. Therefore the charging base for each tariff may be different.

4.4. **Option 1: Base the Tariff charging base on the demand capacity in the Transport Model for both peak and year round locational tariffs.**

4.4.1. This option utilises the current capacity based methodology that underpins the Transport Model. Consequently Supplier charges for both peak and year round would be based on the underlying assumptions regarding ACS peak demand. Charges would be set accordingly and levied on supplier forecast demand. These charges could be reconciled to actual annual demand to ensure consistent cost recovery. Therefore the charging base would be:

- **Peak Security Locational Tariff**: Forecast supplier ACS Peak Demand adjusted for actual demand outcome (£/kW); and
- **Year Round Locational Tariff:** Forecast supplier ACS Peak Demand adjusted for actual demand outcome (£/kW).

4.4.2. The benefits of this approach are that the locational charging arrangements are directly related to the capacity-based assumptions in the Transport Model. On this basis the charges could be considered to be more cost reflective than the current arrangements.

4.4.3. The drawback with this approach is that it would provide incentives to avoid charges for **both** the peak and year round charges. This would appear to undermine the principle in relation to promoting optimal use of the transmission system, since it would create a “peak” incentive in relation to “year round charges”.

4.5. Option 2: Supplier capacity-based peak tariffs and a year round supplier commodity tariff for year round tariffs (the CMP271 Proposal)

4.5.1. This option would use the existing locational tariffs derived from capacity but address the charging base differently. The peak charges would be based on supplier forecast demand at the Triad (with no differentiation between half hour and non-half hour consumption.). The year round tariff would be converted into a year round commodity tariff for each supplier (again with no differentiation between half hour and non-half hour consumption). Therefore the charging base would be:

- **Peak Security Locational Tariff**: Forecast supplier ACS Peak Demand adjusted for actual demand outcome (£/kW); and
- **Year Round Locational Tariff:** Forecast supplier ACS Peak Demand converted into a commoditised tariff based of forecast supplier consumption across the year and adjusted for actual demand outcome (£/kWh).

4.5.2. The benefits of this approach are that the locational charging arrangements for the peak tariff are directly related to the capacity-based assumptions in the Transport Model while the commodity tariff is more closely related to the assumptions that reflect the year round conditions on the system. Clearly the peak tariff would retain some element of the Triad base charges. This approach would complement the wider charging objectives in relation to stable cost messages and be implementable.

4.5.3. The main drawback of this approach is that the year round tariff no longer directly relates to the capacity based approach in the Transport Model. The key question is whether a commodity based charge is a better proxy for the security standard when compared to the current basis of charging.

4.6. Option 3: Supplier capacity-based peak tariffs and a supplier commodity tariff for Year Round tariffs based on 16:00 – 19:00 supplier forecast demand

4.6.1. This option would use the current charging arrangements for the Triad but the charging base for base peak tariffs would be supplier peak demand (no distinction between half-hour and non-half hour) and base the year round tariff on supplier forecast consumption between 16:00 and 19:00. Therefore the charging base would be:

- **Peak Security Locational Tariff**: Forecast supplier ACS Peak Demand adjusted for actual demand outcome (£/kW); and
- **Year Round Locational Tariff:** Forecast supplier ACS Peak Demand in the 16:00 – 19:00 periods converted into a commoditised tariff based on supplier consumption across the year and adjusted for actual demand outcome (£/kWh).

4.6.2. The benefits of this approach are that resembles the current charging regime, notably the Triad based charging for the peak tariff and the 16:00 to 19:00 charging period for the year round element. Therefore there are benefits in terms of simplicity of implementation. However it is based on total supplier demand rather than a distinction between half hourly and non-half hourly demand.

4.6.3. Clearly this approach moves away from the underlying capacity based charge that forms the basis of charging in the transport model. Again, the key question is whether a commodity based charge is a better proxy for the security standard when compared to the current basis of charging.

4.7. Option 4: Supplier capacity based peak tariffs for half-hourly demand and a supplier commodity tariff for year round tariffs based on 16:00 – 19:00 supplier non half hourly demand

4.7.1. This option would use the current charging arrangements for the Triad for peak tariffs which would be applied half hourly demand. The year round tariff would be applied to the non-half hour demand charging base. Therefore the charging base would be:

- **Peak Security Locational Tariff**: Forecast supplier half hourly ACS Peak Demand adjusted for actual demand outcome (£/kW); and
- **Year Round Locational Tariff:** Forecast supplier non half hourly ACS Peak Demand in the 16:00 – 19:00 periods converted into a commoditised tariff based on supplier consumption across the year and adjusted for actual demand outcome (£/kWh).

4.7.2. This approach maintains the distinction between half hourly and non-half hourly charging bases with respect to the two locational tariffs. Therefore it maintains key elements of the current charging regime, and would be simple to implement. .

4.7.3. The main drawback of this approach is the use of half hourly and non-half hourly demand as a basis of charge. There is no clear rationale for this in terms of the cost reflectivity in terms of the application of charges (as noted above). Furthermore, as the introduction of smart meters will further complicate the incentive properties associated with the locational tariffs.

5. Negative and Positive Marginal MWkm and Cost Recovery

5.1. One of the key questions for the cost reflectivity of the locational signals is whether it is appropriate to create and apply the negative and positive locational signals in the tariffs. Given the incentive properties, it is appropriate to consider whether ii is a correct incentive to increase or reduce demand in certain zones during peak periods or year round given the wider impact of such incentives on for example, transmission investment, generation investment and security of supply from short term operation effects.

5.2. However, it is important to preserve the **relative** locational signals derived from the MWkm rather than the **absolute** level of these signals (which simply reflect model assumptions). Consequently if it were determined that it is inappropriate to provide negative peak demand signals in the locational tariffs then the resultant tariffs should be adjusted so that the lowest zonal tariff was set to zero and the relative marginal signals preserved. This is illustrated in Table 1 and Table 2.

Table 1: Peak Tariffs for 2017/18 rebased to avoid negative charges

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Tariff (£/kW)	Peak Security Tariff Adjuster £/KW	Effective Peak Security Zonal Tariff (£/kW)	Adjusted Zonal Revenue (£m)
1	Northern Scotland	0.923	1.87	-6.19	8.06	7.44
2	Southern Scotland	3.109	0.02	-6.19	6.21	19.30
3	Northern	2.267	-2.67	-6.19	3.51	7.97
4	North West	3.854	-0.71	-6.19	5.47	21.09
5	Yorkshire	3.566	-2.58	-6.19	3.61	12.87
6	N Wales & Mersey	2.350	-1.82	-6.19	4.37	10.27
7	East Midlands	4.360	-2.13	-6.19	4.06	17.68
8	Midlands	4.125	-1.41	-6.19	4.78	19.70
9	Eastern	6.036	1.04	-6.19	7.23	43.62
10	South Wales	1.657	-6.19	-6.19	0.00	0.00
11	South East	3.711	3.86	-6.19	10.04	37.27
12	London	4.112	5.05	-6.19	11.23	46.18
13	Southern	5.179	1.68	-6.19	7.87	40.74
14	South Western	2.436	-0.93	-6.19	5.25	12.79
		47.684				296.912

Table 2: Year Round Tariffs for 2017/18 rebased to avoid negative charges

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Year Round Transport Zonal Tariff (£/kW)	Year Round Tariff Adjuster £/KW	Effective Year Round Zonal Tariff (£/kW)	Adjusted Zonal Revenue (£m)
1	Northern Scotland	0.923	-20.11	-20.11	0.00	0.00
2	Southern Scotland	3.109	-17.36	-20.11	2.75	8.56
3	Northern	2.267	-5.92	-20.11	14.19	32.17
4	North West	3.854	-1.85	-20.11	18.26	70.36
5	Yorkshire	3.566	-0.27	-20.11	19.84	70.74
6	N Wales & Mersey	2.350	0.79	-20.11	20.90	49.12
7	East Midlands	4.360	2.21	-20.11	22.32	97.30
8	Midlands	4.125	3.05	-20.11	23.16	95.54
9	Eastern	6.036	0.76	-20.11	20.87	125.98
10	South Wales	1.657	3.92	-20.11	24.03	39.81
11	South East	3.711	0.87	-20.11	20.98	77.85
12	London	4.112	2.11	-20.11	22.22	91.37
13	Southern	5.179	3.91	-20.11	24.02	124.42
14	South Western	2.436	5.08	-20.11	25.19	61.34
		47.684				944.565

5.3. It should be noted that any rebasing of the demand locational tariffs to avoid negative charges and preserve relative locational signals has implications for cost recovery as illustrated in Table 1 and 2. Note that the data in Tables 1 and 2 is based on a capacity charging base in each charging zone (consistent with the Transport Model inputs).

5.4. The nature of locational signals from the Transport Model is influenced by the charging base. Currently the half hour/non half hourly split creates different signals in relation to different users on the transmission system. These issues should be considered further under the cost recovery work stream under CMP271. Further consideration of the appropriate charging base and its effects on locational signals is required if it is determined that it is inappropriate to maintain negative locational demand tariffs.

6. Conclusions

6.1. This paper has considered the issues associated with the cost recovery associated with the locational peak and year round tariffs and their application to an appropriate charging base. The current basis of charging, which combines the locational tariff and applies it to either half hourly demand capacity or non-half hourly consumption may be unsustainable. Indeed the underlying rationale for such an approach in terms of efficient locational signals may be questionable while such an approach appears incompatible with the underlying charging objectives set out in the CUSC.

6.2. There are a number of options available for applying the peak and year round tariffs to differing charging bases ranging from capacity based tariffs to some form of capacity/commodity split. The capacity approach is most closely aligned with the underlying assumptions of the Transport Model which is based on capacity. However, a split based on a peak capacity base for the peak tariff and a commodity base for the year round tariff may have favourable incentives, particularly in relation to the underlying rationale for the "year round" element of the Transport Model (as representing year round conditions on the transmission system)

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Annex A: Investment Cost Related Pricing (ICRP) methodology and demand tariffs

Introduction

A.1. The Investment Cost Related Pricing (ICRP) methodology introduced in 1993/94 is used to calculate transmission charges in Great Britain (GB). The charges are based on deriving the marginal investment cost of additional demand or generation using a DC Load Flow model (the Transport Model).

The Transport Model

A.2. The ICRP methodology considers the effects of an incremental MW at each node on the transmission system. This is achieved through increasing generation and demand at each node and identifying the incremental effects. The impact of the marginal MW is measured in "MWkm" (which can be positive and negative) for each node the Transport Model.

A.3. The marginal effects are categorised as related to either a "Peak Security" or a "Year Round" background, which reflect drivers for investment in transmission assets as set out in the National Electricity Transmission System (NETS) System Quality and Security Standard (SQSS).

A.4. The SQSS makes certain assumptions about the generation and demand capacity of each node on the system which are used in the Transport Model:

- The Peak Security scales "conventional generation" to meet ACS (average cold spell) peak demand (there is no contribution from "intermittent" generation capacity"); and
- The Year Round background assumes fixed scaling factors for "intermittent" generation and scales conventional generation to meet ensure that ACS peak demand is satisfied.

Transport Model Outputs

A.5. The output from the Transport Model is marginal MWkm grouped together into GSP Groups for demand and generation zones for each background weighted by the relevant demand or generation capacity. Generation zones are based on grouping nodes that are electrically and geographically proximate using a fixed differential (+/-1.00kW) for the wider marginal costs.

A.6. The zonal tariffs are derived by multiplying the marginal MWkm by an "expansion constant" which reflects the assumed incremental costs per MW of transmission investment and a "security factor" that reflects the requirement network resilience (using the N-1 standard). The incremental MW and the derived £/kW tariffs for demand in 2017/18 are illustrated in Table A1.

Table A1: Demand tariffs in 2017/18[18]

Derivation of Zonal Demand HH Tariffs			Peak Security			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Peak Security Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	-76.64	-1,040.45	-1,872.81	1.87
2	Southern Scotland	3.109	-0.92	-12.52	-22.54	0.02
3	Northern	2.267	109.32	1,484.00	2,671.21	-2.67
4	North West	3.854	29.20	396.42	713.56	-0.71
5	Yorkshire	3.566	105.43	1,431.27	2,576.29	-2.58
6	N Wales & Mersey	2.350	74.35	1,009.29	1,816.72	-1.82
7	East Midlands	4.360	87.18	1,183.56	2,130.41	-2.13
8	Midlands	4.125	57.72	783.51	1,410.31	-1.41
9	Eastern	6.036	-42.63	-578.77	-1,041.79	1.04
10	South Wales	1.657	253.13	3,436.39	6,185.50	-6.19
11	South East	3.711	-157.88	-2,143.29	-3,857.92	3.86
12	London	4.112	-206.46	-2,802.83	-5,045.10	5.05
13	Southern	5.179	-68.74	-933.11	-1,679.61	1.68
14	South Western	2.436	38.22	518.83	933.90	-0.93
		47.684				

Derivation of Zonal Demand HH Tariffs			Year Round			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Year Round Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Year Round Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	822.95	11,171.82	20,109.28	-20.11
2	Southern Scotland	3.109	710.26	9,642.03	17,355.65	-17.36
3	Northern	2.267	242.23	3,288.41	5,919.15	-5.92
4	North West	3.854	75.87	1,029.97	1,853.94	-1.85
5	Yorkshire	3.566	11.04	149.88	269.78	-0.27
6	N Wales & Mersey	2.350	-32.53	-441.54	-794.77	0.79
7	East Midlands	4.360	-90.30	-1,225.84	-2,206.52	2.21
8	Midlands	4.125	-125.02	-1,697.14	-3,054.86	3.05
9	Eastern	6.036	-31.20	-423.55	-762.40	0.76
10	South Wales	1.657	-160.60	-2,180.14	-3,924.24	3.92
11	South East	3.711	-35.48	-481.64	-866.95	0.87
12	London	4.112	-86.43	-1,173.33	-2,112.00	2.11
13	Southern	5.179	-160.13	-2,173.79	-3,912.82	3.91
14	South Western	2.436	-207.76	-2,820.41	-5,076.74	5.08
		47.684	932.92			

A.7. Based on the demand capacity and the transport tariffs an initial estimate of the revenue recovery through the locational tariffs can be derived from the model for each background. This is illustrated in Table A2 for the 2017/18 Demand Tariffs.

[18] The "Total Demand Charge Base: Triad Demand" is the peak demand on the transmission system for the purpose of setting tariffs

Table A2: Notional revenue recovery from demand locational tariffs using demand capacities

Derivation of Zonal Demand HH Tariffs				
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Revenue (£m)	Year Round Transport Zonal Revenue (£m)
1	Northern Scotland	0.923	1.73	-18.57
2	Southern Scotland	3.109	0.07	-53.96
3	Northern	2.267	-6.06	-13.42
4	North West	3.854	-2.75	-7.15
5	Yorkshire	3.566	-9.19	-0.96
6	N Wales & Mersey	2.350	-4.27	1.87
7	East Midlands	4.360	-9.29	9.62
8	Midlands	4.125	-5.82	12.60
9	Eastern	6.036	6.29	4.60
10	South Wales	1.657	-10.25	6.50
11	South East	3.711	14.32	3.22
12	London	4.112	20.74	8.68
13	Southern	5.179	8.70	20.27
14	South Western	2.436	-2.27	12.37
		47.684	**1.96**	**-14.33**

Charging Methodology

A.8. For the purpose of applying the tariffs to Supplier demand in the charging methodology under the CUSC, the zonal demand locational tariffs in the model are combined for each zone (peak and year round locational tariffs are added together). The effect of the combined locational tariff using the demand capacity methodology on revenue recovery is illustrated in Table A3.

Table A3: Notional zonal demand revenue recovery from combined locational tariffs in 2017/18 (excluding the residual component of the tariff and based on the current charging methodology)

Derivation of Capped Zonal Demand NHH Tariffs			Final HH Demand Tariffs	
Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	923.39	-18.24	-16.84
2	Southern Scotlan	3,109.18	-17.33	-53.89
3	Northern	2,266.99	-8.59	-19.47
4	North West	3,853.96	-2.57	-9.90
5	Yorkshire	3,565.78	-2.85	-10.15
6	N Wales & Merse	2,349.89	-1.02	-2.40
7	East Midlands	4,360.13	0.08	0.33
8	Midlands	4,124.58	1.64	6.78
9	Eastern	6,035.90	1.80	10.89
10	South Wales	1,656.54	-2.26	-3.75
11	South East	3,711.20	4.72	17.53
12	London	4,111.70	7.16	29.43
13	Southern	5,179.46	5.59	28.97
14	South Western	2,435.66	4.14	10.09
		47,684.35		**-12.37**

A.9. The final stage in the charging methodology is to adjust the locational charges to ensure overall cost recovery. This is through a “residual” adjustment to the tariffs (Table A4).

Table A4: Combined locational demand tariffs and residual adjustment

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Final Locational Tariff (£/kW)	Residual Tariff (£/kW)	Final Zonal Tariff (£/kW)
1	Northern Scotland	923.39	-18.24	47.98	29.75
2	Southern Scotland	3,109.18	-17.33	47.98	30.65
3	Northern	2,266.99	-8.59	47.98	39.39
4	North West	3,853.96	-2.57	47.98	45.42
5	Yorkshire	3,565.78	-2.85	47.98	45.14
6	N Wales & Mersey	2,349.89	-1.02	47.98	46.96
7	East Midlands	4,360.13	0.08	47.98	48.06
8	Midlands	4,124.58	1.64	47.98	49.63
9	Eastern	6,035.90	1.80	47.98	49.79
10	South Wales	1,656.54	-2.26	47.98	45.72
11	South East	3,711.20	4.72	47.98	52.71
12	London	4,111.70	7.16	47.98	55.14
13	Southern	5,179.46	5.59	47.98	53.58
14	South Western	2,435.66	4.14	47.98	52.13
		47,684.35			

A.10. Tariffs are applied to half hourly demand base on a "half hourly" p/kW tariff applied to system peak demand capacity measured across the three half hours in the winter separated by 10 days (the Triad demand) (Table A5).

Table A5: Half hour demand tariffs and revenue recovery 2017/18.

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Final Zonal Tariff (£/kW)	Chargeable HH Zonal Triad Demand (MW)	HH Zonal Triad Demand Revenue Recovery (£m)
1	Northern Scotland	923.39	-18.24	- 668.025	-19.87
2	Southern Scotland	3,109.18	-17.33	641.726	19.67
3	Northern	2,266.99	-8.59	314.289	12.38
4	North West	3,853.96	-2.57	1,174.622	53.35
5	Yorkshire	3,565.78	-2.85	1,106.638	49.95
6	N Wales & Mersey	2,349.89	-1.02	519.724	24.41
7	East Midlands	4,360.13	0.08	1,456.313	69.99
8	Midlands	4,124.58	1.64	1,400.271	69.49
9	Eastern	6,035.90	1.80	1,472.861	73.33
10	South Wales	1,656.54	-2.26	554.199	25.34
11	South East	3,711.20	4.72	870.404	45.88
12	London	4,111.70	7.16	2,194.260	121.00
13	Southern	5,179.46	5.59	1,649.598	88.38
14	South Western	2,435.66	4.14	540.175	28.16
		47,684.35		**13,227.05**	**661.46**

A.11. Tariffs are applied to the "non-half hour" charging base through a p/KWh tariff based on supplier demand from 16:00 to 19:00 hrs every day over the financial year. (Table A6).

Table A6: Locational Non half hour demand tariffs adjusted for the residual and revenue recovery 2017/18.

Derivation of Capped Zonal Demand NHH Tariffs

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Chargeable HH Zonal Triad Demand (MW)	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share (%)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	923.39	- 668.025	-19.87	1,591.42	47.34	0.752253	3%	6.29
2	Southern Scotland	3,109.18	641.726	19.67	2,467.45	75.63	1.763499	7%	4.29
3	Northern	2,266.99	314.289	12.38	1,952.71	76.93	1.286790	5%	5.98
4	North West	3,853.96	1,174.622	53.35	2,679.33	121.69	2.063560	8%	5.90
5	Yorkshire	3,565.78	1,106.638	49.95	2,459.14	111.00	1.850096	7%	6.00
6	N Wales & Mersey	2,349.89	519.724	24.41	1,830.17	85.95	1.295523	5%	6.63
7	East Midlands	4,360.13	1,456.313	69.99	2,903.82	139.56	2.226530	9%	6.27
8	Midlands	4,124.58	1,400.271	69.49	2,724.31	135.21	2.097776	8%	6.45
9	Eastern	6,035.90	1,472.861	73.33	4,563.04	227.19	3.189258	13%	7.12
10	South Wales	1,656.54	554.199	25.34	1,102.34	50.40	0.870233	3%	5.79
11	South East	3,711.20	870.404	45.88	2,840.79	149.74	1.995657	8%	7.50
12	London	4,111.70	2,194.260	121.00	1,917.44	105.73	1.927899	8%	5.48
13	Southern	5,179.46	1,649.598	88.38	3,529.86	189.12	2.675603	11%	7.07
14	South Western	2,435.66	540.175	28.16	1,895.49	98.81	1.318527	5%	7.49
		47,684.35	**13,227.05**	**661.46**	**34,457.30**	**1,614.29**	**25.313203**		

Annex 4: Paper prepared on <u>residual cost recovery</u> by RWE for discussion at the CMP271 Modification Workgroup

CMP271 – Initial thoughts on residual cost recovery in a GB Demand Transmission Charge

Executive Summary

i. This paper considers the issues associated with the recovery of the allowed revenue for Transmission Owners through a GB demand transmission charge. Currently cost recovery is ensured through the addition of a residual component to the locational tariffs. This residual is material and increasingly significant in demand charges. Ofgem have highlighted that the residual may distort the electricity and capacity markets by creating excessive incentives to avoid costs for embedded generation and demand side response.

ii. In developing alternative approaches it is essential that they meet objective criteria for assessment. This paper reviews some of the work associated with tariff evaluation and suggests criteria that could be used for assessment. Alternative cost recovery charging arrangements including supplier capacity charges and supplier meter charges are assessed using these criteria. Further issues associated with the treatment of vulnerable customers, implementation timescales and the relevant charging entities are discussed.

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1. Introduction

1.1. This paper provides initial thoughts on the nature of recovery of allowed transmission revenue through a GB demand transmission charge. In particular it considers the current methodology for cost recovery in Section 2 and the interaction between cost recovery and locational tariffs in Section 3. Possible additional tariff components to ensure transmission owner cost recovery are discussed in Section 4. Section 5 presents alternative approaches to ensure cost recovery and Section 6 considers the wider implications of these approaches. Section 7 concludes.

1.2. These are initial thoughts on the potential issues associated with the cost recovery of transmission owner revenues for the purpose of discussion at the CMP271 Working Group. The paper considers the residual component of the tariff separately from the locational component of the tariffs (see the CMP271 work streams A and B).

2. Background

2.1. The principles establishing the basis for ensuring that the GB Transmission owners recover the allowed revenue in GB electricity transmission tariffs are set out in Section 14 of the Connection and Use of System Code (CUSC). Locational tariffs are derived from a DC Load Flow model (the Transport Model) which implements the Investment Cost Related Pricing Methodology (ICRP) first introduced by National Grid in 1993/94. Recovery of the required revenue is part of the charging methodology and requires uplift of the locational tariffs.

2.2. The rationale for revenue recovery is expressed as follows in the CUSC:

"*14.15.130 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges (TRRt) is set after adjusting for any under or over recovery for and including, the small generators discount*".

2.3. The locational tariffs derived from Transport Model do not recover costs from users. Rather they reflect a marginal incremental cost signal on users. The CUSC recognises this and states that:

"*14.15.131 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs [ITT] will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected*".

2.4. To ensure cost recovery of the allowed revenue a residual component is added to the initial transport tariffs. This is stated in the CUSC as follows:

*"14.15.132 …in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved".*

2.5. The addition of the residual to the locational tariffs allows the "effective" final tariffs to be calculated for both generation and demand. This calculation is expressed in the CUSC Section 14.15.133 as follows:

14.15.133 The effective Transmission Network Use of System tariff (TNUoS) can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$ and

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

ET=Effective TNUoS Tariff expressed in £/kW (ET_{Gi} would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances ITT_{GiPS}, ITT_{GiYRNS} and ITT_{GiYRS} will be applied using Power Station specific data)

For the purposes of the annual Statement of Use of System Charges ET_{Gi} will be published as ITT_{GiPS}; ITT_{GiYRNS}, ITT_{GiYRS}, RT_G and LT_{Gi}

2.6. In this formula the following definitions are used:

- ITT means Initial Transport Tariff;
- RT_G means Residual Tariff for Generation
- GiPS means Generation Peak Security
- GiYRNS means Generation Year Round not-shared
- GiYRS means Generation Year Round Shared
- LT_{GI} means Local Tariff Generation

- DiPS means Demand Peak Security
- DiYR means Demand Year Round; and
- RT_D means the Residual Tariff for Demand

2.7. The residual tariff is adjusted to ensure the 27%:73% allocation of cost recovery to generation and demand, and to respect the 2.5euros cap on allowed cost recovery for Generation tariffs (this is a binding constraint for cost recovery from generation tariffs). The effective generation/demand split for cost recovery in 2017/18 (Dec forecast) is 14.6% from generation and 85.4% from demand.

3. The impact of the residual on demand locational charges

3.1. The demand residual has a material and significant effect on demand locational tariffs. This can be illustrated by reference to the 2017/18 tariffs (Table 1).

Table 1: Locational demand tariffs for 2017/18 – Dec Forecast

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Peak Security Transport Zonal Tariff (£/kW)	Year Round Unadjusted Zonal Wtd Marginal (km)	Year Round Transport Zonal Tariff (£/kW)	Residual Tariff (£/kW)	Final Zonal HH Tariff (£/kW)
1	Northern Scotla	0.923	-76.64	1.87	822.95	-20.11	47.98	29.75
2	Southern Scotla	3.109	-0.92	0.02	710.26	-17.36	47.98	30.65
3	Northern	2.267	109.32	-2.67	242.23	-5.92	47.98	39.39
4	North West	3.854	29.20	-0.71	75.87	-1.85	47.98	45.42
5	Yorkshire	3.566	105.43	-2.58	11.04	-0.27	47.98	45.14
6	N Wales & Mer	2.350	74.35	-1.82	-32.53	0.79	47.98	46.96
7	East Midlands	4.360	87.18	-2.13	-90.30	2.21	47.98	48.06
8	Midlands	4.125	57.72	-1.41	-125.02	3.05	47.98	49.63
9	Eastern	6.036	-42.63	1.04	-31.20	0.76	47.98	49.79
10	South Wales	1.657	253.13	-6.19	-160.60	3.92	47.98	45.72
11	South East	3.711	-157.88	3.86	-35.48	0.87	47.98	52.71
12	London	4.112	-206.46	5.05	-86.43	2.11	47.98	55.14
13	Southern	5.179	-68.74	1.68	-160.13	3.91	47.98	53.58
14	South Western	2.436	38.22	-0.93	-207.76	5.08	47.98	52.13
		47.684	201.27		932.92			

3.2. The data in Table 1 indicates that the residual component of the tariff has a key impact on the incentive properties of the locational tariff for users. For example, users benefit most from avoidance of the tariff by locating in southern Britain. However, the uniform application of the residual uplift ensures that the relative locational signals are preserved.

3.3. The application of the locational tariffs to the half hour/non-half hour supplier charging base, together with the adjustment for the small generation discount determines the actual final tariffs and associated incentives including tariff avoidance (Table 2).

Table 2: Final Half hour and Non half hour tariffs for 2017/18

Demand		Dec forecast	
Zone No.	Zone Name	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	30.395559	6.381455
2	Southern Scotland	31.298919	4.376830
3	Northern	40.041679	6.066212
4	North West	46.064536	5.985106
5	Yorkshire	45.785960	6.087929
6	N Wales & Mersey	47.610087	6.722479
7	East Midlands	48.708140	6.356156
8	Midlands	50.276580	6.533291
9	Eastern	50.436217	7.211672
10	South Wales	46.370777	5.879999
11	South East	53.356908	7.591258
12	London	55.789133	5.572371
13	Southern	54.224465	7.156419
14	South Western	52.774877	7.581867
	Tariffs include small gen tariff of:	0.647411	0.088128

3.4. Ofgem have noted[19] that the residual component of the tariff may result in distortions to the electricity market. Ofgem have highlighted that:

"With the increase in overall TNUoS charges and the rapid increase in the volume of EG [Embedded Generation], the size of TNUoS demand residual payments has grown as has the number of parties receiving them. This creates a large benefit to connecting to the distribution network rather than the transmission network".

3.5. Ofgem have indicated that:

"We are concerned that the size and increase of the TNUoS demand residual payments may now be distorting the market by:

- *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);*
- *leading to TG exiting because it cannot compete;*
- *distorting dispatch by dampening prices at peak times when EG dispatch out of merit to generate in the triad periods;*
- *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; and*
- *distorting innovation in the market towards parties who can best capture this large payment".*

4. Recovering transmission owner costs

4.1. While the current methodology ensures that the transmission owners recover their allowed revenue, it has a material impact on the incentive properties of the tariffs (as noted by Ofgem[20]). The key question for this section is: What the appropriate methodology for ensuring that the

[19] For example see the Ofgem open letter on "Charging arrangements for embedded generation", 29th July 2016 at https://www.ofgem.gov.uk/publications-and-updates/open-letter-charging-arrangements-embedded-generation
[20] Ofgem Open Letter, op cit

transmission companies achieve their allowed revenue while ensuring the any associated market distortions are minimised.

4.2. There is a body of academic literature associated with electricity network cost recovery. This recognises the fact that marginal cost signals from network simulation models do not recover the actual costs of owning and operating an electricity network (actual investment costs and maintenance of the system). For example Perez-Arriaga et al (1995)[21] state that

"*Strict marginal network revenues (here renamed as variable charges) are clearly insufficient in practice to recover the network costs*"; and

"*In actual systems a mismatch exists between marginal network revenues and total costs, because of a number of reasons"…."They include discrepancies between static and dynamic optimal expansion plans, planning deviations and errors, the strongly discrete nature of investments, economies of scale, reliability constraints, other constrains on network investments*"

4.3. A useful summary of the issues associated with cost recovery of electricity network costs is provided by Brown and Faruqui (2014) in a report prepared by the Brattle Group for the Australian Energy Market Commission[22].

4.4. Brown and Faruqui (2014) identify a number of criteria that could be used to assess the effectiveness of the approach towards the recovery of network owners' costs. They cite the following:

"*Professor James C. Bonbright is the most widely quoted expert on the subject. In his text on public utility tariffs (Bonbright, 1961[23] and 1988[24]), he lays out ten principles for tariff design. These do not specifically focus on the pricing of distribution network services because when he was writing all utilities were vertically-integrated and distribution network services were not unbundled. Nevertheless, the ten principles noted below provide a framework within which distribution tariffs should be evaluated:*

1. *Effectiveness in yielding total revenue requirements, without encouraging undesirable over-investment or discouraging reliability and safety.*
2. *Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to the utility companies.*
3. *Stability and predictability of the tariffs themselves, with a minimum of unexpected changes that are seriously adverse to utility customers.*
4. *Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use.*
5. *Reflection of all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities).*
6. *Fairness in the allocation of costs among customers so that equals are treated equally.*
7. *Avoidance of undue discrimination so as to avoid subsidising particular customer groups.*

[21] Perez-Arriaga I.J., Rubio F.J, Puerta J.F, Arceluz J. and Marin J, "Marginal pricing of transmission services: An analysis of cost recovery", IEEE Transactions on Power Systems, Vol.10 No1, February 1995 (Perez-Arriaga et al, (1995)).

[22] Brown T. and Faruqui A. (2014) "Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs", Report prepared by the Brattle Group for the Australian Energy Market Commission, August 2014. A link to the report can be found at http://www.brattle.com/news-and-knowledge/news/brattle-experts-prepare-report-for-the-australian-energy-market-commission-on-recovering-residual-costs-from-electricity-distribution-network-tariffs

[23] Bonbright, James C. Principles of Public Utility Rates, Columbia University Press, 1961.

[24] Bonbright, James C., Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Second Edition, Public Utilities Reports, Inc., 1988

8. *Dynamic efficiency in promoting innovation and responding to changing supply–demand patterns.*
9. *Simplicity, certainty, convenience of payment, economy in collection, comprehensibility, public acceptability, and feasibility of application.*
10. *Freedom from controversies as to proper interpretation".*

4.5. Brown and Faruqui (2014) conclude that in considering cost recovery the issues are as follows:

"We found the following principles to be relevant for structuring tariffs to recover residual costs.

- *The guiding principle in the academic literature is Ramsey pricing, or the "inverse elasticity" rule. Residual costs should be recovered from the various services provided by the firm and the various groups of customers served in inverse proportion to the respective price elasticity of demand. The intuition behind this rule is that the broader goal is to have efficient tariffs based on LRMC, and that departures from LRMC induce inefficiencies. The magnitude of the inefficiencies is minimized if the movement in prices away from LRMC is concentrated on those tariffs or parts of the tariff which have the smallest elasticities.*

- *In practice, utilities and regulatory authorities place significant weight on equity or "fairness" considerations. We found that the "fairness principle" is subject to multiple interpretations when it comes to tariff design. In one interpretation, fairness means that tariffs should not be changed so drastically that certain customers experience large bill increases in a short period of time while others experience large bill decreases. In a second interpretation, it means that a change in tariff design should not result in a significant change in the revenue recovered from any one class. And in a third interpretation, it means that all customers in a class should pay the same average tariff expressed in cents per kWh, $ per kW, or some combination thereof. Finally, there is the idealized theory of fairness and justice propounded by the late Harvard professor, John Rawls, regarded by many as the most significant philosopher of the twentieth century. One of the key elements of the theory is the Rawlsian concept of the "Difference Principle." Rawls argued that the greatest benefit should be accorded to the most disadvantaged members of society[25]. Those who advocate lower tariffs for vulnerable customers are knowingly or unknowingly citing the ideas of Rawls.*

- *Finally, the principle of "gradualism" suggests that tariffs should change gradually to reflect the long-term nature of investment in end-use electrical equipment, and the fact that such investment was made based on reasonable expectations about future tariffs. Gradualism avoids shocking and inconveniencing customers with sudden bill increases and simultaneously benefiting others with sudden bill decreases*".

4.6. Brown and Faruqui (2014) consider a number of different approaches towards cost recovery based on some form of either:

- "**Ramsey" pricing**: based on "*charging different prices to different customer groups (or, in the case of multi-product or multi-service firms, charging different mark-ups over marginal cost on different products or services). Customers who are price inelastic are charged a higher price than those who are price elastic, and thus more of the residual costs are*

[25] http://www.crf-usa.org/bill-of-rights-in-action/bria-23-3-c-justice-as-fairness-john-rawls-andhistheory-of-justice. Also see: http://plato.stanford.edu/entries/rawls/.

recovered from customers who are price inelastic than from the customers with elastic demand. This has come to be known as the inverse elasticity rule"; or

- **Non-linear pricing:** based on "*a fixed charge and a volumetric charge which could be flat or have a block tariff structure (inclining or declining). The fixed charge would be designed to recover the fixed costs of generation, transmission and distribution while the volumetric charge would be designed to recover the variable costs of generation, mostly fuel, and possibly variable transmission and distribution costs (losses). If the appropriate metering infrastructure is in place, the volumetric charge could have a time-varying character which could either be static (e.g., two or three period time-of-use tariffs) or dynamic (e.g., critical peak pricing or real time pricing").*

4.7. The following section considers potential options for the recovery of GB transmission owner costs.

5. **Alternative approaches towards transmission cost recovery**.

5.1. This section considers possible approaches towards to recovery of the transmission allowed revenue in demand transmission charges. The starting point for this discussion is the proposal in CMP271 that the cost recovery element of the tariff is explicitly decoupled from the locational part of the tariff. Therefore this section only considers the revenue required to meet the "target revenue figure" for the transmission owners.

Option 1: Half hour charges for net supplier capacity and net non-half hour charges for supplier energy (using the 16:00-19:00 periods)

5.2. This option is based on the current approach towards the charging base which separates out the half hour and non-half hour charges. It is envisages that suppliers would be liable for a charge based on their half hour consumption at the peak (as a triad-based capacity charge) and a commodity charge based on supplier consumption in the 16:00 – 19:00 periods.

5.3. The principle drawback associated with this approach is the incentive properties created to avoid the charge for half hourly customers. Essentially the option replicates the problems associated with the current residual. Over rewarding peak embedded generation or demand reduction carries the risk of inefficient investment in the transmission system and distorts the electricity and capacity markets. In addition, the incentive properties are enhanced as customers transfer from non-half hour meters to half hourly meters, and the option does not address issues associated with "behind the meter" generation.

Variant 1a: Half hour charges for gross supplier capacity and gross non half hour charges for supplier energy (using the 16:00-19:00 periods)

5.4. This option is also based on the current approach towards the charging base but is based on **gross** half hour capacity and **gross** non half hour charges. It is envisages that suppliers would be liable for a charge based on their gross half hour capacity at the peak (as a triad-based capacity charge) and a gross commodity charge based on supplier consumption in the 16:00 – 19:00 periods.

5.5. The principle drawback associated with this approach remains the incentive properties created to avoid the charge particularly in this case for customers "behind the meter". Essentially this approach will still over reward certain peak embedded generation or demand reduction which carries the risk of inefficient investment in the transmission system and distortion in the electricity and capacity markets.

Option 2: Supplier charges based on annual energy consumption (The P271 proposal)

5.6. For simplicity the CMP271 proposal includes a potential approach towards cost recovery based on supplier consumption throughout the year. Essentially the approach would commoditise the residual as a £/kWh tariff. This approach is analogous to the approach adopted for Balancing Services Use of System (BSUoS) charges and would be relatively simple to implement using existing processes and systems.

5.7. The principal benefit of the BSUoS-type approach is that is significantly dilutes the embedded benefit by smearing the costs across all settlement periods in the year. However, this may over reward high load factor embedded which may have a significant cost advantage over transmission connected generation (there is an avoidable cost benefit). Nevertheless this approach may be better than the current baseline, which significantly over rewards embedded peak generation.

5.8. The potential issues associated with BSUoS charges have been highlighted by Ofgem in their open letter which stated that

"We have concerns that the BSUoS embedded benefit is likely to distort operational decisions (i.e. dispatch), by bringing some generators into merit at times when they should be out of merit (i.e. rendering it profitable for them to generate at times when otherwise it would not be profitable for them to generate)".

5.9. Ofgem have also noted the following with regard to the current BSUoS arrangements:

"However whilst we think there is a rationale for changing these charging arrangements, we do not currently think the BSUoS embedded benefit is a matter of similar priority to the TNUoS demand residual element of embedded benefit for the following reasons:

- *the BSUoS embedded benefit is smaller and hence causes less distortion to dispatch;*
- *it likely has a lower overall cost to consumers; and*
- *there are significant interactions with possible future development of local balancing which Ofgem is considering through our work on issues relating to Flexibility. We consider that these need to be thought through carefully and future work in this area scoped alongside other changes"*.

Option 3: Supplier capacity charge

5.10. Under this approach suppliers would be subject to annual charges based on their year round capacity. Essentially annual consumption would be converted to a £/kW charge for suppliers. The actual tariff recovery would be subject to annual reconciliation.

5.11. This approach significantly dilutes any embedded benefits and is simple to implement. However it maintains the level embedded benefits based on avoided capacity charges, which may distort the wider electricity and capacity market. Over rewarding embedded generation and demand reduction may result in inefficient investment and issues associated with cross subsidy

Option 4: Supplier consumption class metering systems and consumption charge

5.12. This approach is based on the consumption class of supplier demand and the number of meters in a consumption class for each supplier. A fixed charge per meter for each supplier can be calculated

5.13. The approach can be illustrated by considering data[26] on the annual consumption of domestic and non-domestic customers in GB and the number of meters in each category (Table 3).

Table 3: Domestic and Non Domestic Consumption in GB

	Total Cosumption	Total Domestic Meters	Average Consumption per meter
2014 Figures	GWh	Thousands	kWh
Domestic	109,170	27,611	3,954
Non Domestic	186,150	2,436	76,402

5.14. Based on the data in Table 3 a charge per meter can be calculated by apportioning the total cost to be recovered by consumption class (in this case domestic/non domestic) and dividing the cost by the number of meters in each class (Table 4).

Table 4: Domestic/Non Domestic cost recovery through a meter charge for 2017/18 required revenue

2017/18	Required Residual Revenue (£m)	Apportionment based on consumption £m	Charge Per Meter £
Demand Cost Recovery	**2,288.12**		
Domestic		845.8	30.63
Non Domestic		1442.3	592.07

5.15. The Option 4 approach is illustrated by reference to domestic and non-domestic consumption classes. Clearly in calculating a Supplier's liability the approach could use the actual consumption classes used in settlement, the number of meters allocated to each consumption class and an adjustment to reflect outturn supplier demand. The approach could also provide adjustments to Supplier liabilities for customers that switch suppliers during a charging year. In addition suppliers could be billed daily for their liabilities and invoiced monthly in arrears.

5.16. The Option 4 approach has the benefit of relative simplicity in its application. In deriving a fixed charge per meter it removes any incentive properties associated with avoidance of the charge and better meets the principles of Ramsey pricing.

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[26] "Sub-national electricity and gas consumption statistics", Department of Energy and Climate Change, 22 December 2015 at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/527628/Sub-national_electricity_and_gas_consumption_summary_report_2014.pdf

Merits of charging options

5.17. The relative merits of the charging options can be illustrated by reference to the Bonbright principles identified above. An evaluation for each option is illustrated in Table 5.

Table 5: Initial evaluation of Cost Recovery options by reference to the Bonbright (1961, 1988)[27] principles

Bonbright Criteria		Option1 Based on Current	Option 2 P271 - commodity	Option 3 Supplier Capacity	Option 4 Meters and consumption	Comments
1	Effective recovery					*Options 1-3 create incentives to avoid costs and over reward embedded*
2	Revenue Recovery					*All options are designed to ensure revenue recovery*
3	Stability, predictability					*All rely of some form of ex post adjustment for supplier volumes*
4	Static efficiency					*Option 4 is closest to Ramsey Pricing, all others createincentives to avoid costs*
5	Inernalise externalities					*Recovery of all transmission costs is ensured*
6	Fairness					*Option 1-3 may over reqard tarnsmission chagre avoidance (not cost reflective)*
7	No undue discrmination					*Certain customers can avoid costs under options 1-3, with cross subsidies*
8	Dynamic Effciency					*Option 4 is closest to Ramsey Pricing, all others createincentives to avoid costs*
9	Simplicity					*Option 2-4 are relatively simple but HH/NHH is more comlex*
10	Understandable					*Relatively simple and rules are clear for all options*

Fails to meet criteria	
Partially meets criteria	
Meets criteria	

5.18. Brown and Faruqui (2014)[28] suggest that the key tests for any change relate to Ramsey pricing; fairness and the nature of any implementation approach.

5.19. The following section considers further issues that may be taken into account in evaluating options for cost recovery under CMP271.

[27] Bonbright (1961) (1988) *op cit*

[28] Brown and Faruqui (2014), *op cit*

6. Further issues for cost recovery

6.1. This section considers further issues for cost recovery that arise as a result of CMP271 but which may be beyond the scope of the modification proposal and the CUSC.

Vulnerable Customers

6.2. As noted by Brown and Faruqui (2014), the recovery of transmission owner allowed revenue should be subject to a test of fairness in its application. In this context, the application of the cost recovery charge to certain classes of customer including vulnerable customers is relevant.

6.3. Given the impact of an additional charge on, for example, low income households, it may be considered appropriate to provide some form of relief for this class of customer. However, any relief from the supplier charge for vulnerable customers must be considered carefully since it would result in discriminatory treatment and some form of cross subsidy. The key question in the design of such arrangements is whether the discrimination can be justified (due discrimination).

6.4. The CUSC arrangements themselves are probably not the place to consider in detail the potential design of arrangements for the treatment of different classes of customers differently. The charging arrangements essentially relate to charges for suppliers without any differentiation or discrimination. In addition, the way that suppliers charge their customers is a matter for suppliers. However, it may be considered appropriate to develop some sort of arrangements for vulnerable customers under the terms of the supply licence. This is beyond the scope of this modification and is a matter for Ofgem and suppliers.

Implementation: cliff edge, delayed or gradual implementation

6.5. As noted by Brown and Faruqui (2014)[29] the approach towards implementation can be a significant consideration in the acceptability of any potential change in the tariff arrangements. There are a number of issues:

- A **cliff edge** approach may create issues for legitimate expectations associated with current approach towards tariffs and creates a risk of stranded assets. However, if the defect in the charging arrangement is material then it is imperative that the customer harm is addressed as soon as practicable;
- **Delayed Implementation** may allow users to adapt to a prospective change. The key issue for his approach is the duration of the delay and the potential customer harm that could occur as a result. It should be noted that it has been argued that there may be a requirement for some form of delay to allow users to adapt commercial arrangements and implement required system changes; and
- **Gradual implementation** implies some form of phased approach towards the change which could involve a hybrid approach towards the arrangements (part existing/part changed). Again the issue here is the duration of any phasing and the potential for customer harm arising from maintenance of the existing arrangements. A gradual approach could have a longer duration than a delayed implementation. However, phasing over a considerable time period would have the potential for a transition period that is unjustified (perpetual transition). In addition, the nature of any phasing arrangement would require careful consideration (how would the current arrangements exist alongside the new arrangements) and certainly carries the risk of increasing the complexity of the charging methodology.

[29] Brown and Faruqui (2014), op cit

6.6. The approach towards implementation is an integral part of the CUSC modification process and will require careful consideration on the context of CMP271.

Supplier charges or Distribution charges?

6.7. The CUSC arrangements relate to the recovery of costs from suppliers. However, it may be appropriate to consider whether suppliers are the appropriate vehicle for the recovery of transmission costs. In this context, an alternative approach would be to recover the costs from Distribution Network Owners (DNOs) rather than suppliers. In turn DNOs could recover the costs from customers through the DNO charging arrangements.

6.8. Clearly and proposal for the recovery of transmission costs through DNO charges would require careful design in the DNO charging methodology. The considerations outlined elsewhere in this paper would come into play. At the moment DNO charges include fixed charged (standing charges) and some variable charges (time of use or commodity charges). The design of distribution tariffs to recover an additional £2-3bn of transmission costs is beyond the scope of the CUSC modification proposal (and this paper).

7. **Conclusions**

7.1. This paper has examined the issues associated with the recovery of transmission owner allowed revenues. The current approach associated with a residual uplift is unsustainable given the potential for distortion arising in the electricity and capacity market. However, the design of an alternative approach requires careful thought and a trade-off between simplicity of implementation and the risks of creating other potentially detrimental effects.

7.2. CMP271 has proposed that cost recovery should be achieved through a year round supplier commodity charge, reflecting the current BSUoS approach. While simple to implement this approach may create an unjustified incentive for cost avoidance. Alternative approaches based on supplier capacity may also have detrimental incentive properties. An alternative has been outlined based on a fixed per meter charge, and this may have some merits.

7.3. Further work is clearly required to consider the nature of the cost recovery arrangement for transmission owner costs. This should consider the effects of such arrangements on the incentive properties for cost avoidance provided to users connected to the transmission system

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Annex A: Investment Cost Related Pricing (ICRP) methodology and demand tariffs

Introduction

A.1. The Investment Cost Related Pricing (ICRP) methodology introduced in 1993/94 is used to calculate transmission charges in Great Britain (GB). The charges are based on deriving the marginal investment cost of additional demand or generation using a DC Load Flow model (the Transport Model).

The Transport Model

A.2. The ICRP methodology considers the effects of an incremental MW at each node on the transmission system. This is achieved through increasing generation and demand at each node and identifying the incremental effects. The impact of the marginal MW is measured in "MWkm" (which can be positive and negative) for each node the Transport Model.

A.3. The marginal effects are categorised as related to either a "Peak Security" or a "Year Round" background, which reflect drivers for investment in transmission assets as set out in the National Electricity Transmission System (NETS) System Quality and Security Standard (SQSS).

A.4. The SQSS makes certain assumptions about the generation and demand capacity of each node on the system which are used in the Transport Model:

- The Peak Security scales "conventional generation" to meet ACS (average cold spell) peak demand (there is no contribution from "intermittent" generation capacity"); and
- The Year Round background assumes fixed scaling factors for "intermittent" generation and scales conventional generation to meet ensure that ACS peak demand is satisfied.

Transport Model Outputs

A.5. The output from the Transport Model is marginal MWkm grouped together into GSP Groups for demand and generation Zones for each background weighted by the relevant demand or generation capacity. Generation zones are based on grouping nodes that are electrically and geographically proximate using a fixed differential (+/-1.00kW) for the wider marginal costs.

A.6. The zonal tariffs are derived by multiplying the marginal MWkm by an "expansion constant" which reflects the assumed incremental costs per MW of transmission investment and a "security factor" that reflects the requirement network resilience (using the N-1 standard). The incremental MW and the derived £/kW tariffs for demand in 2017/18 are illustrated in Table A1.

Table A1: Demand tariffs in 2017/18[30]

Derivation of Zonal Demand HH Tariffs			Peak Security			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Peak Security Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	-76.64	-1,040.45	-1,872.81	1.87
2	Southern Scotland	3.109	-0.92	-12.52	-22.54	0.02
3	Northern	2.267	109.32	1,484.00	2,671.21	-2.67
4	North West	3.854	29.20	396.42	713.56	-0.71
5	Yorkshire	3.566	105.43	1,431.27	2,576.29	-2.58
6	N Wales & Mersey	2.350	74.35	1,009.29	1,816.72	-1.82
7	East Midlands	4.360	87.18	1,183.56	2,130.41	-2.13
8	Midlands	4.125	57.72	783.51	1,410.31	-1.41
9	Eastern	6.036	-42.63	-578.77	-1,041.79	1.04
10	South Wales	1.657	253.13	3,436.39	6,185.50	-6.19
11	South East	3.711	-157.88	-2,143.29	-3,857.92	3.86
12	London	4.112	-206.46	-2,802.83	-5,045.10	5.05
13	Southern	5.179	-68.74	-933.11	-1,679.61	1.68
14	South Western	2.436	38.22	518.83	933.90	-0.93
		47.684				

Derivation of Zonal Demand HH Tariffs			Year Round			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Year Round Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Year Round Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	822.95	11,171.82	20,109.28	-20.11
2	Southern Scotland	3.109	710.26	9,642.03	17,355.65	-17.36
3	Northern	2.267	242.23	3,288.41	5,919.15	-5.92
4	North West	3.854	75.87	1,029.97	1,853.94	-1.85
5	Yorkshire	3.566	11.04	149.88	269.78	-0.27
6	N Wales & Mersey	2.350	-32.53	-441.54	-794.77	0.79
7	East Midlands	4.360	-90.30	-1,225.84	-2,206.52	2.21
8	Midlands	4.125	-125.02	-1,697.14	-3,054.86	3.05
9	Eastern	6.036	-31.20	-423.55	-762.40	0.76
10	South Wales	1.657	-160.60	-2,180.14	-3,924.24	3.92
11	South East	3.711	-35.48	-481.64	-866.95	0.87
12	London	4.112	-86.43	-1,173.33	-2,112.00	2.11
13	Southern	5.179	-160.13	-2,173.79	-3,912.82	3.91
14	South Western	2.436	-207.76	-2,820.41	-5,076.74	5.08
		47.684	932.92			

A.7. Based on the demand capacity and the transport tariffs an initial estimate of the revenue recovery through the locational tariffs can be derived from the model for each background. This is illustrated in Table A2 for the 2017/18 Demand Tariffs.

[30] The "Total Demand Charge Base: Triad Demand" is the peak demand on the transmission system for the purpose of setting tariffs

Table A2: Notional revenue recovery from demand locational tariffs using demand capacities

Derivation of Zonal Demand HH Tariffs				
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Revenue (£m)	Year Round Transport Zonal Revenue (£m)
1	Northern Scotland	0.923	1.73	-18.57
2	Southern Scotland	3.109	0.07	-53.96
3	Northern	2.267	-6.06	-13.42
4	North West	3.854	-2.75	-7.15
5	Yorkshire	3.566	-9.19	-0.96
6	N Wales & Mersey	2.350	-4.27	1.87
7	East Midlands	4.360	-9.29	9.62
8	Midlands	4.125	-5.82	12.60
9	Eastern	6.036	6.29	4.60
10	South Wales	1.657	-10.25	6.50
11	South East	3.711	14.32	3.22
12	London	4.112	20.74	8.68
13	Southern	5.179	8.70	20.27
14	South Western	2.436	-2.27	12.37
		47.684	**1.96**	**-14.33**

Charging Methodology

A.8. For the purpose of applying the tariffs to Supplier demand in the charging methodology under the CUSC, the zonal demand locational tariffs in the model are combined for each zone (peak and year round locational tariffs are added together). The effect of the combined locational tariff using the demand capacity methodology on revenue recovery is illustrated in Table A3.

Table A3: Notional zonal demand revenue recovery in 2017/18 (excluding the residual component of the tariff and based on the current charging methodology)

Derivation of Capped Zonal Demand NHH Tariffs			Final HH Demand Tariffs	
Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	923.39	-18.24	-16.84
2	Southern Scotlan	3,109.18	-17.33	-53.89
3	Northern	2,266.99	-8.59	-19.47
4	North West	3,853.96	-2.57	-9.90
5	Yorkshire	3,565.78	-2.85	-10.15
6	N Wales & Merse	2,349.89	-1.02	-2.40
7	East Midlands	4,360.13	0.08	0.33
8	Midlands	4,124.58	1.64	6.78
9	Eastern	6,035.90	1.80	10.89
10	South Wales	1,656.54	-2.26	-3.75
11	South East	3,711.20	4.72	17.53
12	London	4,111.70	7.16	29.43
13	Southern	5,179.46	5.59	28.97
14	South Western	2,435.66	4.14	10.09
		47,684.35		**-12.37**

A.9. The final stage in the charging methodology is to adjust the locational charges to ensure overall cost recovery. This is through a "residual" adjustment to the tariffs (Table A4).

Table A4: Demand locational Tariffs and Residual Adjustment

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Final Zonal Revenue Recovery (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)	Final Zonal Tariff (£/kW)
1	Northern Scotla	0.923	- 18.24	47.98	44.31	29.75
2	Southern Scotla	3.109	- 17.33	47.98	149.19	30.65
3	Northern	2.267	- 8.59	47.98	108.78	39.39
4	North West	3.854	- 2.57	47.98	184.93	45.42
5	Yorkshire	3.566	- 2.85	47.98	171.10	45.14
6	N Wales & Mer	2.350	- 1.02	47.98	112.76	46.96
7	East Midlands	4.360	0.08	47.98	209.22	48.06
8	Midlands	4.125	1.64	47.98	197.92	49.63
9	Eastern	6.036	1.80	47.98	289.63	49.79
10	South Wales	1.657	- 2.26	47.98	79.49	45.72
11	South East	3.711	4.72	47.98	178.08	52.71
12	London	4.112	7.16	47.98	197.30	55.14
13	Southern	5.179	5.59	47.98	248.53	53.58
14	South Western	2.436	4.14	47.98	116.87	52.13
		47.684			**2,288.12**	

A.10. The tariffs are then applied to half hourly demand based on a "half hourly" p/kW tariff applied to system peak demand capacity measured across the three half hours in the winter separated by 10 days (the Triad demand) and a "non-half hour" p/KWh tariff based on supplier demand from 16:00 to 19:00 hrs every day over the financial year. (Table A5).

Table A5: Demand tariffs and revenue recovery 2017/18.

Derivation of Capped Zonal Demand NHH Tariffs

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Chargeable HH Zonal Triad Demand (MW)	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share (%)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	923.39	- 668.025	-19.87	1,591.42	47.34	0.752253	3%	6.29
2	Southern Scotland	3,109.18	641.726	19.67	2,467.45	75.63	1.763499	7%	4.29
3	Northern	2,266.99	314.289	12.38	1,952.71	76.93	1.286790	5%	5.98
4	North West	3,853.96	1,174.622	53.35	2,679.33	121.69	2.063560	8%	5.90
5	Yorkshire	3,565.78	1,106.638	49.95	2,459.14	111.00	1.850096	7%	6.00
6	N Wales & Mersey	2,349.89	519.724	24.41	1,830.17	85.95	1.295523	5%	6.63
7	East Midlands	4,360.13	1,456.313	69.99	2,903.82	139.56	2.226530	9%	6.27
8	Midlands	4,124.58	1,400.271	69.49	2,724.31	135.21	2.097776	8%	6.45
9	Eastern	6,035.90	1,472.861	73.33	4,563.04	227.19	3.189258	13%	7.12
10	South Wales	1,656.54	554.199	25.34	1,102.34	50.40	0.870233	3%	5.79
11	South East	3,711.20	870.404	45.88	2,840.79	149.74	1.995657	8%	7.50
12	London	4,111.70	2,194.260	121.00	1,917.44	105.73	1.927899	8%	5.48
13	Southern	5,179.46	1,649.598	88.38	3,529.86	189.12	2.675603	11%	7.07
14	South Western	2,435.66	540.175	28.16	1,895.49	98.81	1.318527	5%	7.49
		47,684.35	**13,227.05**	**661.46**	**34,457.30**	**1,614.29**	**25.313203**		