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

DRAFT

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*"[1].

[1] CUSC Section 14, paragraph 14.15.4

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 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*."[2]

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*"[3].

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)[4] 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*"

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[2] Connection and Use of System Code (CUSC) Section 14, paragraph 14.14.6

[3] CUSC Section 15, paragraph 14.15.131

[4] 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)).

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 marginal revenues) does not exceed 30%. Reports from similar studies in New Zealand and South Africa appear to confirm these results*"[5]

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[6]. 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"[7].

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*"[8]. 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*"[9].

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

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[5] 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)).

[6] 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

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

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

[9] 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.

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.

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"[10]) or some form of "*locational marginal pricing"* (see for example Baldick et al (2011)[11]). 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.

[10] 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*
[11] 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.

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. 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[12]. 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.

[12] CUSC Section 14 paragraph 14.15.25

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**

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[13] 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 fr 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

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

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.

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[14]

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.

[14] 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**		