Year-round System Congestion Costs - Key Drivers and Key Driving Conditions

A report to Centrica and RWE

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Executive Summary

Project scope and approach

Centrica and RWE have commissioned the University of Bath to undertake a review of two aspects of the proposals advanced in the CMP213 Working Group consultation of 7th December 2012. These relate to that part of the CMP213 proposals intended to improve the incremental cost signal in the ICRP methodology. Specifically, the University of Bath has been asked to address:

- The use of a generator annual load factor as a proxy for the causation of constraint costs; and
- The use of a dual background for devising the locational signal in TNUoS charges.

In order to address these points the University of Bath has undertaken a series of high-level studies based on a representation of the GB transmission system so as to test the basis for the CMP213 proposals. These studies focus on the key driving factors which determine year-round congestion costs. The studies attempt to answer three fundamental questions that underpin the network sharing concept.

i) Is it appropriate to assume that load factors can be used to represent a generation technology?

ii) Is it appropriate to assume a linear relationship between load factors and congestion costs, so that load factor can be used as a proxy for year-round congestion costs?

iii) Can a dual background realistically reflect the congestion conditions and thus its costs throughout the year?

Conclusions

The University of Bath supports the industry's effort to enhance the TNUoS charging methodology such that it can recognise the impact of differing generation technologies on incremental transmission network cost/congestion cost, particularly in the light of the rising volume of intermittent renewable generation across the system. However, we have serious misgivings over the direction that 'network sharing' takes in the original CMP213 proposals. We believe the approach proposed could seriously compromise the objectives of project TransmiT which are to "*to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers*".

i) Load factor analysis

Our work demonstrates that a generator's load factor is not a fixed parameter, but a highly complex parameter that is shaped by network location, network characteristics (in terms of length, capacity, utilisation, congestion across each interconnected boundaries), characteristics of generation (such as generation mix, efficiency, controllability, cost curves and output variability), characteristics of demand (such as demand duration curves, and demand profiles), the direction and utilisation of interconnectors, as well as market fundamentals. This is an important result because CMP213 uses a fixed load factor assumption to differentiate generation technologies as a key initial input to deriving charges. These are borrowed from the SQSS and then used to allocate circuits as falling into 'year-round' or 'peak' categories.

Our study shows that for the same generation technology but with different efficiencies (price), location, and boundary congestion levels, generators will have very different load factors. Our example shows that an increase in boundary capacity leads to less congestion resulting in lower cost generation being able to transfer more power thus increasing its load factor, whilst the load factor of the more expensive generation reduces. In the simplified network chosen for the study, when the transmission transfer capacity was increased by 25%, the load factor of the cheaper generator increased from 60% to 65%, while the more expensive generator load factor fell from 12% to 5%. The consultation document also observed that as the penetration of intermittent generation increases, the output of conventional generation will change and evolve with it over time.

Annual load factor for a generation technology is a variable that is shaped by differing generator and demand parameters, and features of the transmission system. It is thus inappropriate to use the same load factor for a generation technology regardless of its locations, efficiencies and market behaviour.

ii) The relationship between load factor and year-round congestion costs

When investigating the possible relationships between year-round congestion cost and annual load factor, we have illustrated how a change in wind penetration level, transmission capacity and generation price characteristics might impact load factor and congestion costs. Our studies demonstrated that under different network, generation and demand conditions the relationship between congestion costs and load factor can vary significantly. The relationship most certainly can not be assumed to be linear.

It is thus impossible to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless account is also

taken of other factors such as location, efficiency, market conditions, and critically, the network transfer capability.

iii) The dual background approach

To examine the validity of introducing a dual background approach into charging as proposed by CMP213, we have developed the concept of a congestion duration curve that charts the variation in the magnitude of congestion costs throughout the year. The objective has been to investigate how congestion cost varies in strength and duration, over time and between locations.

Our study is of a system that comprises a representation of the B6 and B15 boundaries; the two GB boundaries with the heaviest congestions. The congestion duration curve in Figure 1 below shows that congestion arises in varying degrees, over different time periods. Table 1 shows that congestion cost is not only linked to the magnitude of congestion, but critically to time, duration and location.

Part 1 of the curve indicates a period of extremely high congestion where costs are in excess of £44k per settlement period. Although of considerable magnitude this high level of cost is incurred for only 23 settlement periods out of a total of 17,520 in the year. The proportion of the total annual congestion cost in this period is thus relatively small (1.1%), and can for all practical purposes be ignored when approximating the year-round congestion cost.

Part 3 of the curve represents the largest share of the year-round congestion costs but still only accounts for 5,427 settlement periods or 31% of the year. The issue in relation to the CMP213 proposals is that in the original proposals the annual load factor is averaged over the course of the year and consequently its use as a proxy for congestion could severely underestimate the congestion costs over the critical congestion periods; and thus significantly dilute the efficacy of the economic signals.

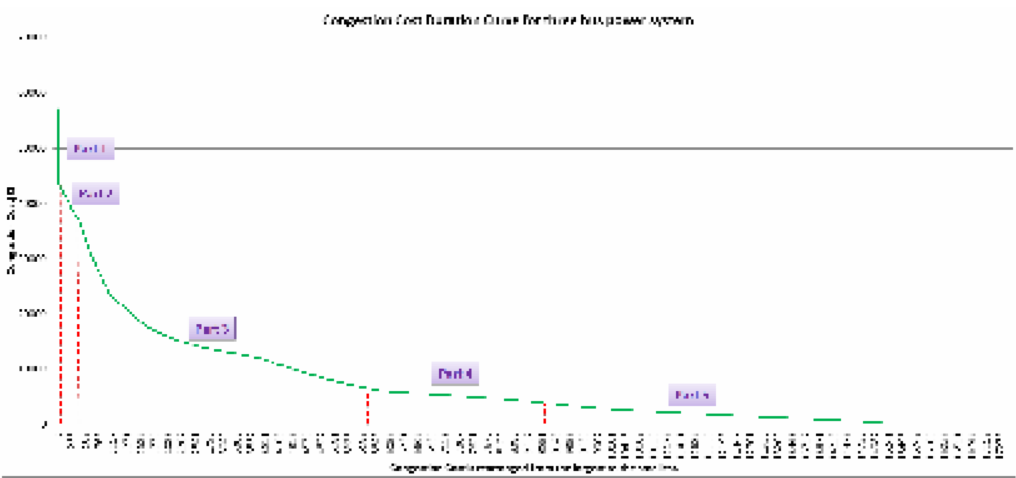

Figure 1: Congestion duration curve.

Table 1: Congestion cost between B6 and B15 for parts of congestion duration curve

	Number of settlement periods	B6 Congestion Cost £M	B15 Congestion Cost £M	Total Congestion Cost £M	Congestion share between different the 5 parts	Proportion of B6 in Total Congestion Cost	Proportion of B15 in Total Congestion Cost
Part 1	23	1.3	0	1,3	1.06%	100.00%	0.00%
Part 2	394	12.0	3.8	15.8	12.87%	75.75%	24.25%
Part 3	5427	67.4	11.3	78.7	63.91%	85.63%	14.37%
Part 4	3042	4.8	10.7	15.5	12.57%	31.44%	68.56%
Part 5	8634	10.9	0.9	11.8	9.58%	92.71%	7.29%
Total	17520	96.5	26.6	123.1	100.0%	78.38%	21.62%

We have also investigated the most significant periods that contribute to the majority of year-round congestion costs, and how the congestion cost is shared between B6 and B15 boundaries. Our study shows that the periods covering parts 2, 3, and 4 of the congestion duration curve shown in Figure 1 account for 94% of system congestion. It is these periods that should be adopted as background scenarios for deriving the year-round congestion costs sine they display both high magnitude and/or long duration.

The study also indicates that congestion costs not only vary over time and duration (different backgrounds), but also vary significantly between boundaries. The B6 boundary is responsible for over 80% of all system congestion, but this congestion does not occur with the same degree or at the same time across as across the B15 boundary. In fact the B6 and B15 boundaries are only congested simultaneously for 14% of the year. Furthermore congestion across B6, when it occurs is significantly higher than across B15. This suggests that congestion cost is sensitive not only to time and duration, but more significantly to the location of the boundary.

These differences of congestion in terms of magnitude, time and location are not reflected in the proposals for an improved ICRP. Employing load factor as a surrogate for the cause of congestion smears the consequence for one boundary across all boundaries and throughout the year. The use of annual load factors in a year-round scenario to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout the year. It cannot provide an appropriate economic message for reducing congestion, and it certainly will not reflect the costs of congestion in accordance with SLC 5.5b

Summary of Key Findings

- Annual load factor of a generation technology is not a fixed parameter but a variable that changes with generation, network and market conditions. It is thus inappropriate to use it as an input for a generation technology regardless of its location, efficiencies and market behaviour.
- The relationship between load factor and congestion cost most certainly can not be assumed to be linear. Load factor is a measure of an average output of a generation technology over the year; whilst congestion cost is sensitive to time (backgrounds), duration elements and boundary locations. The relationship between load factor and congestion cost varies greatly with transmission transfer capabilities, demand profiles and generation mixes, efficiency, controllability and their locations in the system.
- It is not appropriate to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless it is further amended to take account of other factors, such as location, efficiency, market conditions and critically, network transfer capability.
- Even for a simple representation of the GB transmission system it is necessary to recognise at least five different congestion periods that will reflect the incidence of year round congestion. Within each period there are considerable differences in the timing and sharing of network congestion costs between the two most heavily congested boundaries.
- The single “year-round” condition is flawed in that it does not reflect the difference in magnitude, duration and location of the congestion. Instead the scenario proposed will represent an extremely high congestion condition that lasts for a very limited duration, and contributes little towards overall system congestion costs.
- Employing load factor as a surrogate for the cause of congestion smears the consequence for one boundary across all boundaries and throughout the year, by assuming that all boundaries have the same level of congestion at all times in the year. It cannot provide the necessary economic message for reducing congestion, and it certainly will not reflect the costs of congestion as required by the Licence Conditions.
- Our view is that a consequence of adopting the current CMP 213 proposals for an improved ICRP methodology will be to <u>increase</u> congestion costs, which would be perverse given the objectives of project TransmiT . Our conclusion is that employing only two backgrounds would fail to create even the crudest representation of system performance and costs.

Recommendations

- **Targeting TNUoS charges and credits in periods and locations where generator output contributes to, or relieves congestion would be an improvement to the existing**

ICRP methodology. However, this implies a time of use and congestion location feature in TNUoS charges rather than it being linked to generator annual load factors.

- **A TNUoS methodology that related charges to times and boundaries where congestion was most severe would be a significant improvement to the existing methodology. This could be achieved by introducing a time of use element (congestion factor) to the existing peak security based TNUoS charges. The present year-round scenario would be expanded to become a number of scenarios that are directly linked to congestion times and boundaries.**
- **If multiple scenarios with their respective time periods and duration are too complicated, then the existing ICRP methodology should be retained on grounds of simplicity rather than diluting and distorting its pricing incentives. Creating a dual background would be a retrograde step in the reflection of costs, and the provision of useful economic signals for transmission and generation investment.**

1. Introduction and Background

1.1. Study remit

Centrica and RWE have commissioned the University of Bath to undertake a critique of two aspects of the proposals advanced in the CMP213 Working Group consultation of 7th December 2012. These relate to that part of the CMP213 proposals intended to improve the incremental cost signal in the ICRP methodology. Specifically The University of Bath has been asked to address:

- The use of a generator annual load factor as a proxy for the causation of constraint costs; and
- The use of a dual background for devising the locational signal in TNUoS charges.

It has also been suggested that the conclusions should opine on whether a single background would better meet the required charging objectives, instead of the dual background proposed for the Improved ICRP proposals.

1.2. Charging principles

When assessing the merits of any future charging methodology it is useful to consider the relevant licence conditions. Standard Licence Condition SLC.5.2 requires that NGET "*make such modifications of the use of system charging methodology as may be requisite for the purpose of better achieving the relevant objectives*". The relevant objectives are described in SLC 5.5 and oblige NGET to ensure:

(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); and

(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses

NGET recovers its costs through TNUoS and BSUoS charges. TNUoS charges recover the revenues permitted under NGET's price control set by the Authority. TNUoS is currently based on the extant ICRP methodology that produces an economic signal for the location of generation and demand.

BSUoS recovers the costs of securing the system. It mainly comprises the costs of providing reserve in its various forms and the costs of resolving system constraints. The costs recovered by BSUoS have proved extremely volatile and difficult to predict, especially in the short term. BSUoS is levied equally on both generation and supply (in respect of demand) on an ex-post half-hourly basis. Socialising these costs between all parties is a political rather than an economic decision but it sits uneasily with the idea of incorporating constraint cost considerations into TNUoS charges.

1.3. Transmission congestion

The implementation of BETTA on 1st April 2005 increased sharply the costs of resolving constraints as is apparent from the following table:

Table 2: Change in constraint costs following BETTA implementation

£ million	2004/05	2005/06	2006/07
England & Wales	15.1	19.6	20.3
Cheviot (B6) boundary	0	31.6	20.3
Within Scotland	0	28.5	43.9
GB Total	15.1	79.7	93.2

During 2008 NGET provided Ofgem with its forecast of total system constraint costs in 2008/09 and 2009/10. This forecast suggested that costs would increase in these years to £238 million and £262 million respectively, of which around £210 million would be due to actions in the more northern parts of the GB system in each year.

Faced with this escalation Ofgem published (17th February 2009) an open letter expressing concern at NGET's substantially increasing forecast. The letter also noted the constraint costs that had been incurred since BETTA implementation. The data appears to be on a slightly different basis to that in the previous table but shows the same pattern in the two years post BETTA.

Table 3: Trends in constraint costs taken from Ofgem 17 February 2009 letter

£ million	2005/06	2006/07	2007/08
Arising from Scottish actions	70.0	80.0	42.0
Total GB constraint costs	84.0	108.0	70.0

The letter suggested a number of actions that NGET could take. These included:

i Actions to reduce the volume of constraints

ii Reductions in the price paid to resolve constraints iii Reviewing whether the charging mechanisms are "*equitable and appropriate*"

In view of increasing intermittent renewable generation, NGET raised a modification to the Security and Quality of Supply Standards (SQSS) that aimed to differentiate between conventional and intermittent generation when determining the system capacity needed to securely transfer power between zones. GSR009 proposed a "dual criteria" approach when planning reinforcement of the transmission network that would take account of both demand security and economic efficiency. The proposal was approved by Ofgem on 1st November 2011.

1.4. Significant Code Review

On 7th July 2011 the Authority announced that it would conduct a Significant Code Review under SLC 10 of the transmission licence with the objective of implementing the conclusions from its Project TransmiT. Project TransmiT was an open review of the transmission charging and connection arrangements in order to facilitate a smooth transition to a low carbon energy sector. The results of the SCR were published on the 4th May 2012. These noted (in paragraph 5.8) that:

> "*The use of a load flow model is robust if the incremental flows identified closely correlate with the resultant costs. The impact of this would be to promote more efficient decision making by parties… If, however, the relationship between costs and charges is more complex, then the retention of the existing ICRP methodology could have the effect of blunting the signals relating to the need for incremental requirements … and therefore the underlying costs of providing transmission capacity for different users at different locations*"

In the conclusions to the SCR Ofgem went on to direct (paragraph 5.9) that NGET:

> "*Develop an improved form of ICRP that recognises the dual background approach of the recently modified NETS SQSS*".

Ofgem's direction to NGET has introduced an unfortunate confusion that is repeated in the CMP213 proposals. GSR009 requires a "dual criteria" approach when assessing the transmission system capacity that should be provided. The first criterion, the ***demand security criterion***, requires the provision of sufficient capacity such that peak demands can be met without intermittent generation. This effectively carried forward the previous basis for the NETS SQSS. The second criterion, an ***economy criterion***, requires that sufficient transmission system capacity be provided to accommodate all types of generation in order to meet varying levels of demand efficiently. This part of the approach uses a generic Cost Benefit Analysis (CBA) to create an economically efficient balance between the costs of constraints, and the costs of transmission reinforcements.

The intention behind this "dual criteria" approach is clear. The deterministic peak load flow scenario would be overlaid by an economic assessment as to whether it would be more efficient to constrain intermittent generation off and other generation on, or provide additional transmission capacity in the event that the intermittent generation produced output at times of system peak. The Ofgem direction corrupts this starting point by requiring that NGET's modification should be based on a "dual background". CMP213 carries forward this confusion by promoting a peak and year round background as the basis for two separate charges, together with the allocation of circuits to one background or the other.

1.5. CMP213 objectives

Accordingly on 20th June 2012 NGET raised CMP213 with the objectives of:

- i Recognising the network capacity sharing by generators in the Investment Cost Related Pricing (ICRP) TNUoS charge calculation;
- ii Introducing an approach for including HVDC links that parallel the onshore AC network into the charging methodology;
- iii Introducing an approach for including Island links in the charging methodology.

This report addresses two of the issues relevant to the first of the stated objectives for the original CMP213 proposal, and which are raised in the CUSC Modification Working Group consultation of 7th December 2012. These are:

- i The use of generator load factor as a proxy for determining the costs of constraints on the transmission system; and
- ii The use of a dual as opposed to single background as the basis for deriving TNUoS charges for generation.

2 Load Factor as a proxy for determining constraint costs

2.1 Introducing the study

The CMP213 proposal adopts the approach that generator load factor can be used as a proxy for the incidence of constraint costs that would accompany an incremental MW at each node in a charging zone. The assumption is based on the empirical results from the use of the ELSI model which simulates the impact of various scenarios that could accompany future planning backgrounds for the system. The results from these studies have led to the conclusion that the relationship between congestion cost and generator load factor is linear. The methodology proposed for an improved ICRP (IIRCP) therefore asserts that generators with high load factors will contribute more to system congestion regardless of their location and time of generation; and thus should pay a greater proportion of use of system charges.

However, as the Consultation document notes, generator annual load factor is not a cost driver but merely the symptom of the relative economics of each generator "*including its availability, fuel cost, efficiency, CO_2 prices, and subsidies such as ROCs*" (consultation document paragraph 4.21). Furthermore the apparent empirical relationship becomes even less linear where there is a predominance of intermittent generation, which is precisely where theIICRP methodology needs to be most effective if it is to replace the current methodology.

Consequently our inclination is to share much of the disquiet that has been raised by many of the working group at this suggestion. The purpose of the study that is described below is to investigate whether the relationship between congestion cost and load factor is indeed linear.

2.2 The study framework

In this study three factors are chosen for the purpose of investigating their impact on the year-round congestion costs and generator load factor. These were chosen on the basis that they are the factors that are mostly likely to change in the near and medium term. These are the wind penetration level, transmission capacity, and the demand load factor, representing the factors that. The impact of each factor on congestion costs and generator load factor is examined by varying the values of the three factors.

The test system used for this study is illustrated in Figure 2. It is intended as a much simplified representation of the GB transmission system. Bus 1 and bus 2 represent two areas with different generation and load capacities. Area 1, which contains bus 1, has a high installed generation capacity but a low demand. Conversely area 2, which is linked to bus 2 has low generation and high demand. There are three generators in the system, two of which, generator 1 and 2, are thermal generators, and the third is a wind generator. Generators 1 and 3 are connected to bus 1, and are for most of the time behind a transmission constraint. Generator

2, which is the more expensive thermal generator, is connected to bus 2, it is required when there is insufficient generation at bus 1 to meet demand, or the transmission circuit is congested. The parameters for the generator capacities, transmission capacity and peak demand of the test system are given in Table 4. The output assumed for wind generation and demand are taken from actual historical data.

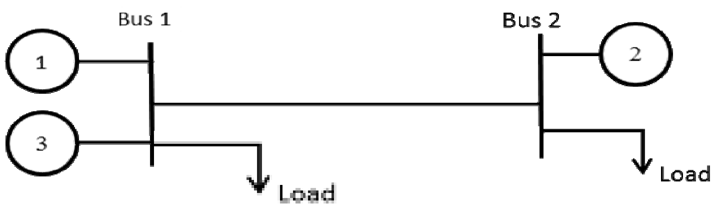

Figure 2: Two-bus test system

Table 4: Two-bus test system parameters

Bus 1					Transmission Capacity	Bus 2				
Thermal Generation		Wind Generation		Load		Thermal Generation		Wind Generation		Load
Price	Capacity	Price	Capacity	30	100	Price	Capacity	Price	Capacity	150
Low	150	0.01	50			High	50	-	-	

The principal assumptions for the model are:

- Thermal generation will be available whenever it is required subject to its rated capacity, which is given in MW in the table;
- Wind generation output is derived directly from the Met office wind speed data for 2011;
- Generator prices are such that generators connected at bus 1 will be despatched first to meet demand, with any resultant congestion being in the direction from bus 1 to bus 2;
- The branch between bus 1 and bus 2 represents the transmission network and is taken to have an appropriate impedance;
- A transmission constraint arises when the transmission capacity limits the power transfer from bus 1 to bus 2;
- Transmission losses and voltages are not considered in the study;
- The demand profile is taken form historical data for the GB power system in 2011;

- Demand profiles for loads at each bus are the same, which implies that the peak demand at bus 1 will be simultaneous with the peak at bus 2.

The simulation is made using Matpower with a DC optimal power flow. Generator offer and bid prices are set equal to their marginal generation cost

The constraint costs are simulated through two successive economic dispatches for each of the 17,520 settlement periods over the course of a year. The first economic dispatch is executed without consideration of the transmission capacity which represents the final physical position notified prior to gate closure. However, if the transmission capacity is exceeded then the generation is re-dispatched by reducing the output of the cheaper generation at bus 1, and increasing the output of the expensive generation at bus 2 until the overloading condition is resolved, i.e. Bid off generation at its marginal price in Bus1, and Offer On generation at Bus 2 at the SRMC. The congestion cost is defined as the cost of resolving the system constraints. Note that no premium is applied to bids and offers in this study, the constraint costs would be higher if these were included.

The model is then used to explore how wind penetration, transmission capacity, and demand load factor will impact the costs of resolving system congestion and be reflected in generator out-turn annual load factor.

2.3 Wind penetration impact on congestion cost & load factor

In order to examine the impact of the wind penetration level, the proportion of wind in the generation mix expressed on a per unit basis is varied between 0.05 to 0.71 times the wind capacity (50MW) of generator 3, whilst the installed capacities of the other generation technologies remains unchanged.

Figure 3 illustrates how the congestion cost changes as the wind penetration level increases from 2.5MW to 35.5MW. Initially the congestion cost increases as the transmission constraint is sustained over a longer period. Eventually the output from the wind generator cannot be transferred to the load centre, and at this point it is necessary to curtail the wind output and the constraint cost begins to decrease (in this study it is assumed that there is no cost to curtail wind, if a premium for Bids for the wind generation is used, then the constraint cost will rise when the curtailment of wind starts).

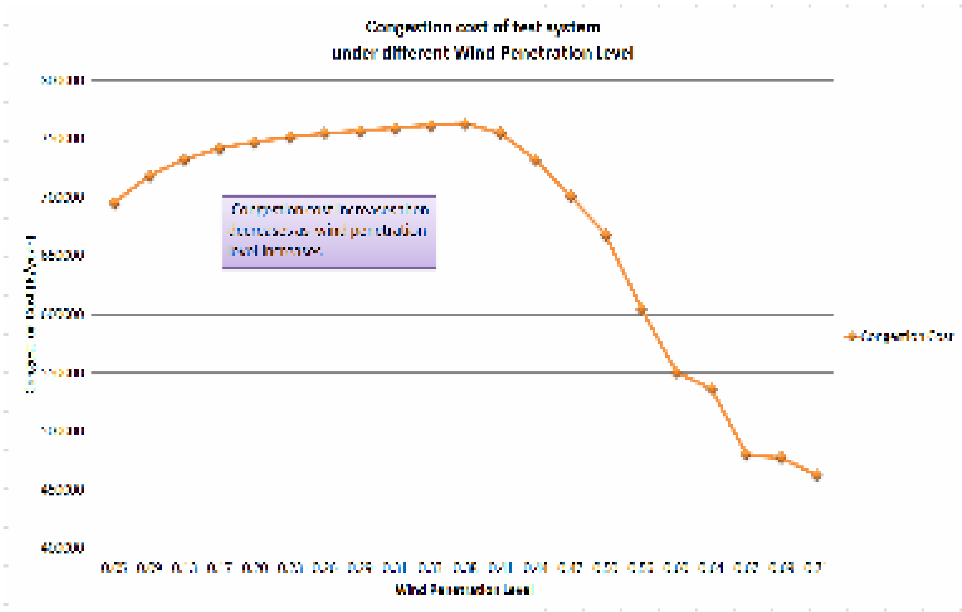

Figure 3: Congestion cost of test system under different wind penetration level.

Figure 4 then depicts the accompanying change in generator load factor with increasing wind generator penetration. The load factor of wind generation (green points in Figure 4) remains constant (at 0.33) until the total congestion cost hits the maximum value corresponding with the 0.38 wind penetration level. Before the maximum congestion is reached the cheaper thermal generation at bus 1 is dominant in determining the transmission capacity utilisation with wind generation replacing the cheaper thermal generation as the wind penetration level increases. The price difference between wind generation and expensive thermal generation drives a higher congestion cost. After the critical peak congestion point the load factor of wind generation starts to decrease, and the wind generation becomes a dominant factor in congestion alongside the cheaper thermal generator.

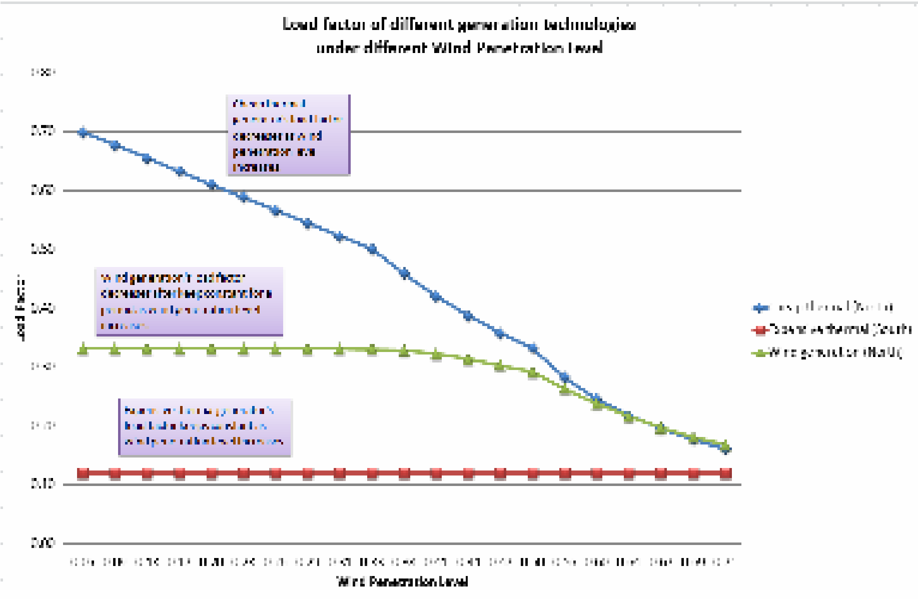

Figure 4: Generator load factors at varying levels of wind penetration

The load factor of the cheaper thermal generation (blue points in Figure 4) also decreases with the increase in wind penetration. As the transmission capacity must be shared between wind and cheap thermal generation it is inevitable that an increase in wind generation capacity will lead to a reduction in the output of the cheaper thermal generation.

The load factor of the expensive thermal generator (red points in Figure 4) remains constant since when demand exceeds the transmission capacity the excess of the demand above the transmission capacity must be met by the more expensive thermal generation.

Figure 5 combines figures 3 and 4 and shows the relationship between the congestion cost and load factor as the wind penetration level increases, which is depicted as a series of points which follow the direct of the arrow. As the wind penetration level increases, the relationship between congestion costs and load factor varies significantly for different generation technologies; the direction of change is shown by the three lines following the direction of arrow.

Before the wind penetration reaches 0.38, the congestion cost rises with decreasing load factors for both of the two generators (wind and low cost thermal) that are behind the constraint. Beyond a 0.38 penetration when wind curtailment starts to be exercised, the congestion cost decreases with decreasing load factors for the two generators behind the constraint. The expensive generator displays a very different picture. Its load factor remains constant as the congestion cost decreases.

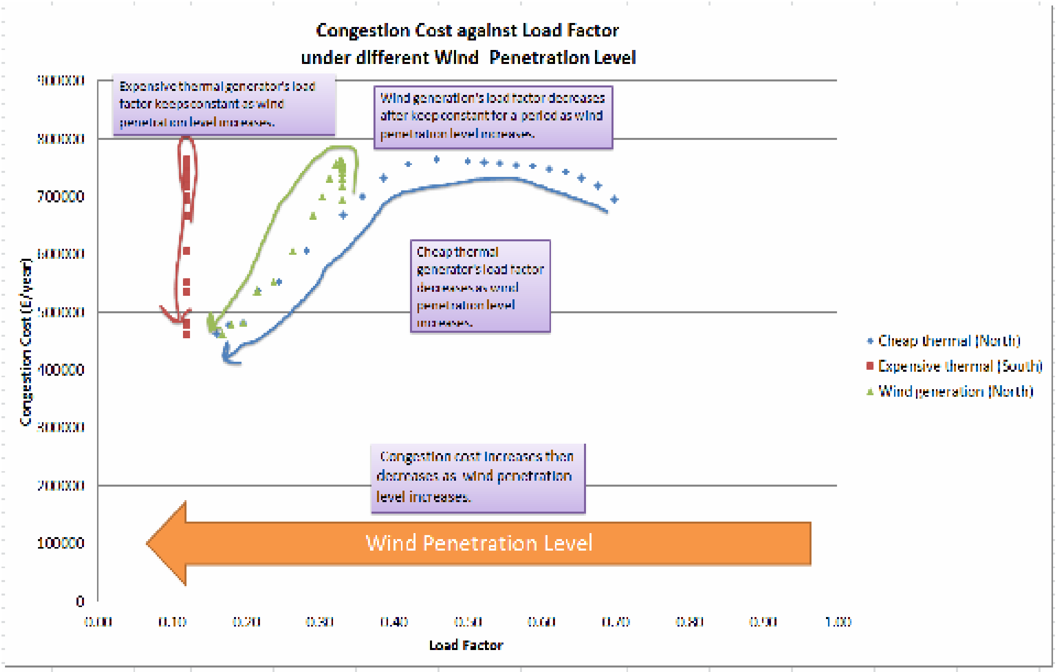

Figure 5: Congestion cost and load factor at different wind penetration levels.

The study emphasises that the load factors of thermal generators will depend upon their location relative to a transmission constraint. The expensive thermal generator that is in front of the transmission constraint has a load factor that is almost constant as the wind penetration changes. The cheaper thermal generation that is behind the transmission constraint has a load factor that decreases as the wind penetration increases and it shares the same transfer capability with the wind generation. The relationship between the expensive thermal generator load factor and the congestion cost is constant, but the relationship between cheaper thermal generator load factor and congestion cost shows a two part curve divided at the point of the peak congestion cost when wind penetration hits 0.38.

The load factor of wind generation depends on both its relative location to a network constraint and its penetration level. Before its penetration hits 0.38 and no generation curtailment is required, load factor is a constant driven by the availability of its natural resource. However, beyond the 0.38 penetration level as wind generation curtailment becomes necessary its load factor reduces as a result of the network constraints.

It is thus starkly apparent that **the relationship between load factor and congestion cost under different wind penetration level is far from linear**. One generation technology can significantly influence the load factor of another generation technology. Generalising the results from this study makes it apparent that **this relationship will vary significantly for generators of different types, locations, prices and the associated low carbon background**.

2.4 The impact of transmission capacity on congestion and load factor

The impact of the available transmission capacity on the year-round congestion cost and generator load factor was investigated by varying the transmission capacity in 5 MW steps from 100 MW to 150 MW. Figure 6 shows how congestion cost decreased as the transmission capacity increased. Figure 7 then tracks the change in the load factor for each generation technology.

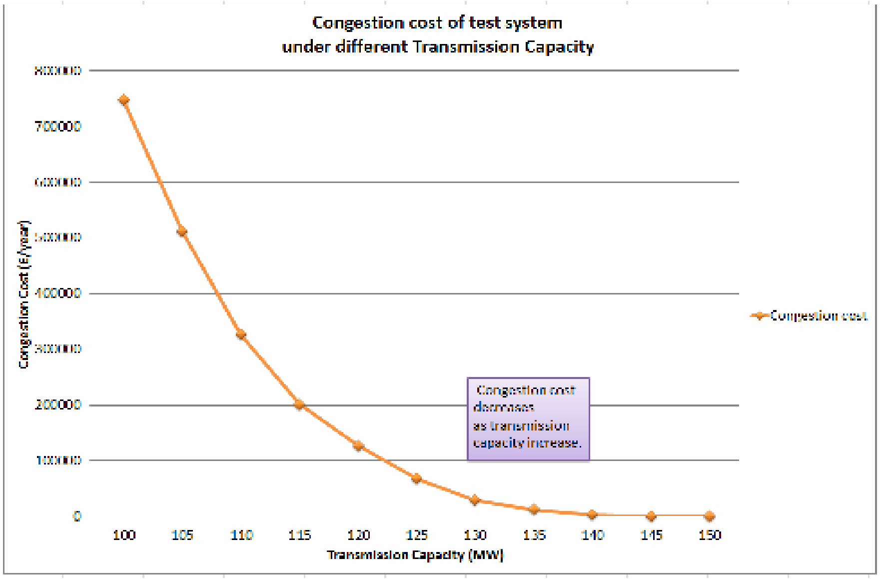

Figure 6: Congestion cost for increasing transmission capacity

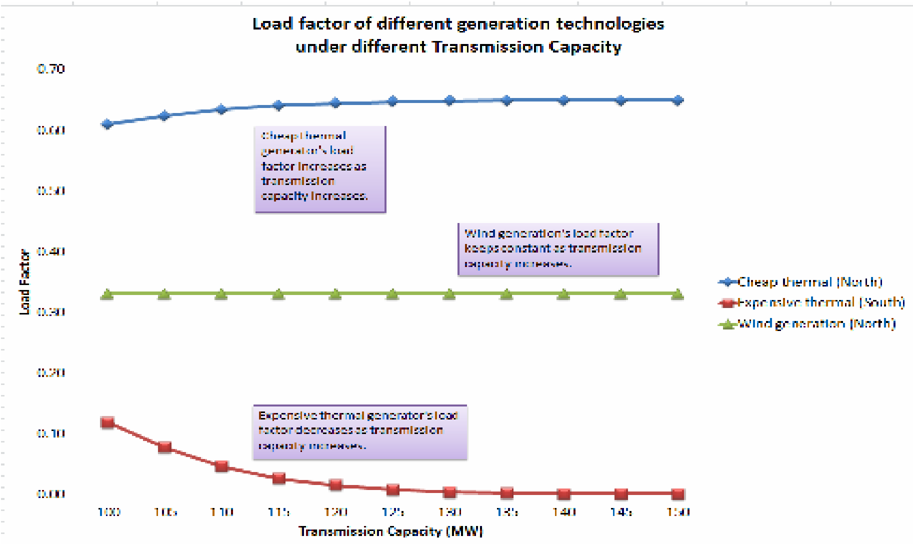

Figure 7: Load factor of generation technologies at different transmission capacity.

As transmission capacity increases the load factor of the cheaper thermal generation (blue points in Figure 7) also rises as it is able to produce more output without being constrained. Conversely the load factor of the expensive thermal generation (red points) reduces. The load factor of wind generation (green points in figure 7) remains constant with the increase in the transmission capacity reflecting the priority for its despatch. This result confirms the view that the annual load factor of individual generators is an output parameter that depends on the generator's price structure, its location, and the value of the transfer capacity between areas.

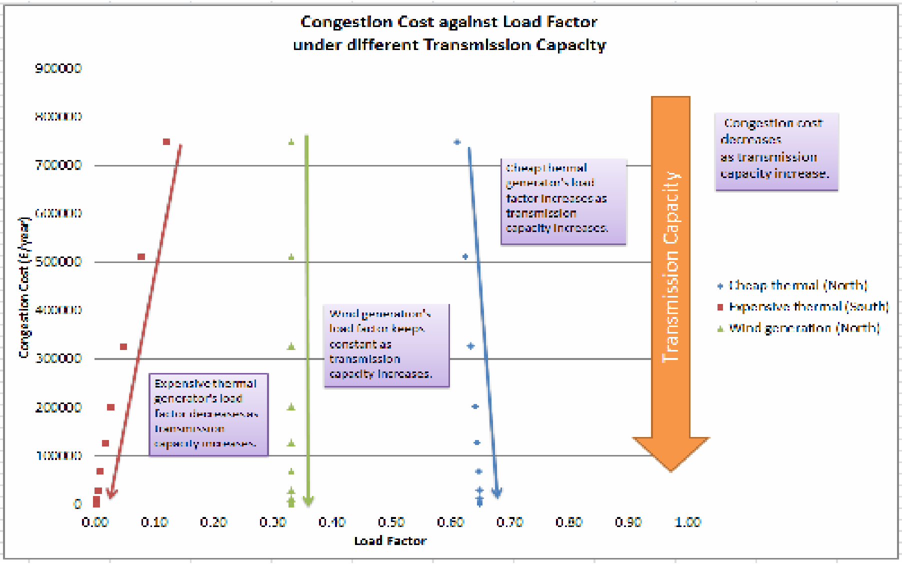

Figure 8: Congestion cost and load factor for different transmisison capacities

Figure 8 provides a scatter plot of the congestion cost for each generation technology against load factor. The trajectory for each technology shows the variation with increasing transmission capacity. Each generator technology shows a linear relationship between load factor and transmission capacity although **whether the correlation is positive or negative now depends on the location of the technology in relation to the constraint. Utilising load factor as a measure of congestion cost without recognising the location of a network constraint would clearly be a flawed assumption.**

2.5 The impact of demand load factor on congestion cost & load factor

The effect of demand load factor on the congestion cost and generator load factor is explored by varying the demand load factor between 0.63 to 0.70 times the peak demand in incremental steps of 0.01. For example this might result from an increased demand side response. In the model it is implemented by reducing the level of peak demand whilst retaining a constant level of annual consumption, thus effectively representing load shifting between time periods.

Figure 9 shows how the congestion costs increase as the demand load factor increases. Figure 10 then depicts how the load factors of the different generation technologies change as the demand load factor increases, and Figure 11 illustrates the relationship between congestion cost and generator technology load factor for changing demand load factor.

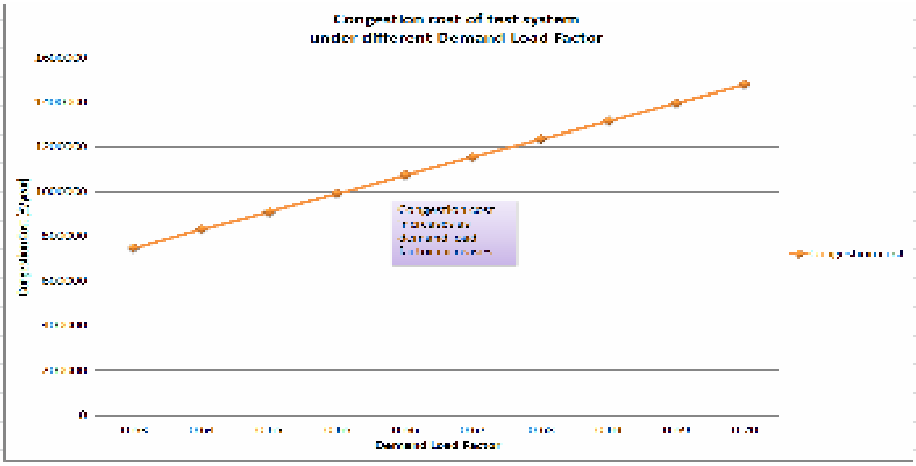

Figure 9: Change in congestion cost for increasing demand load factor.

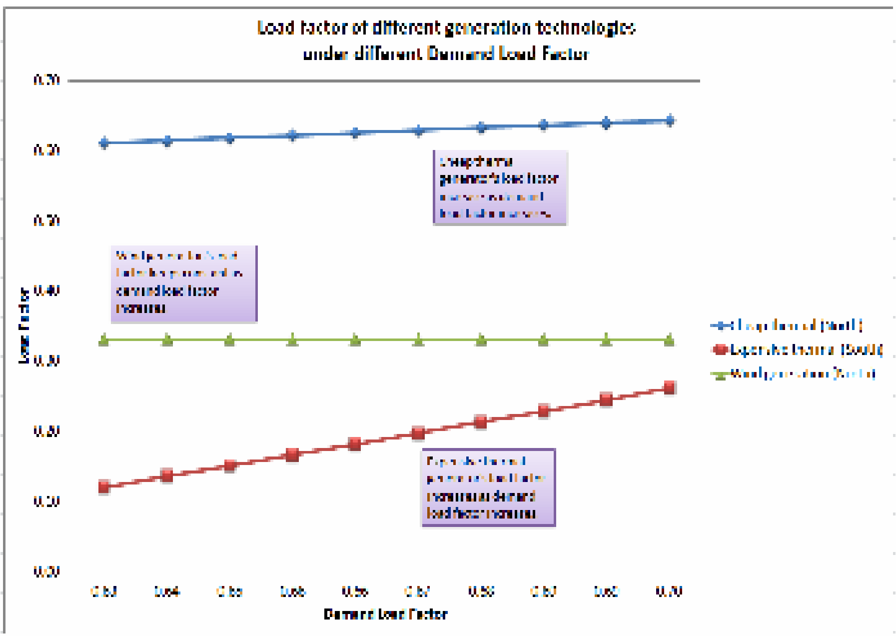

Figure 10: Generator technology load factors for increasing demand load factor

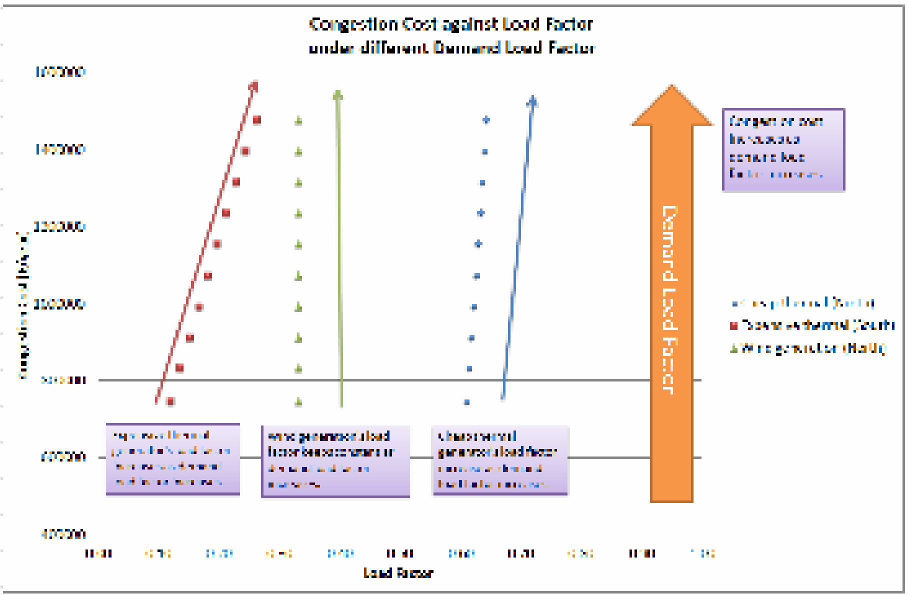

Figure 11: Congestion cost and generator load factor under different demand load factors.

In this simple 2 busbar system the relationship for each generator technology between congestion cost and generator load factor with a changing demand load factor is linear. Both the low cost thermal generation at bus 1, and the expensive thermal generation at bus 2 (respectively the blue and red points in Figures10 and 11) show an increasing congestion cost with load factor. This is because as more electricity per peak MW is required as demand load factor increases, the additional electricity has to be met by the thermal generation.

For wind generation (green points in Figures10 and 11), the installed capacity of wind generation and wind characteristics are fixed, and wind is dispatched as long as it is available. Thus the wind generator load factor is not affected by a changing demand load factor.

2.6 Conclusions

These studies have illustrated that the load factor of a single generation technology is not uniform across the system but will be shaped by different generator and demand parameters, and features of the transmission system. The costs of congestion and generator load factors are the results of these varying combinations. For generation there are a variety of technologies, production prices, generation capacities, and locations. For the transmission network there are differing transmission transfer capacities, impedances and lengths. For demand there are varying load profiles and durations, and the timing of peak demands as subsequently reflected in the demand load factor.

All these features will combine to impact congestion costs and generator load factor in different ways. Whilst based on a relatively simple representation of the GB system our studies have demonstrated that under different network, generation and demand conditions the relationship between congestion costs and load factor will vary significantly. **The relationship most certainly can not be assumed to be linear.**

Instead system congestion tends to be directional with the majority of its associated cost incurred across the B6 boundary and within Scotland, as evidenced by the figures reported by NGET. **Employing load factor as a surrogate for the cause of this congestion would smear the consequence for what is a highly localised problem across all boundaries and throughout the year. It cannot provide the necessary economic message for reducing congestion, and it certainly would not reflect the costs of congestion as required by SLC 5.5(b).**

Southern based controllable CCGT generation would be under rewarded on the basis of its annual average load factor even though it was contributing fully to the relief of system congestion. A more economically efficient arrangement would be one that targeted TNUoS charges and credits to **periods** and **locations** where generator output either **compounded** or **alleviated** congestion. However, this implies a time of use feature in TNUoS charges rather than linking congestion costs with generator class load factors within the methodology.

3. Dual versus single background for deriving TNUoS charges

3.1. Introducing the study

An important feature in the CMP213 proposals for an improved ICRP (IICRP) methodology is the introduction of dual backgrounds that reflect the trade-off between network investment and constraint costs which is now recognised in the SQSS. In the methodology that has been advanced through the working group, a Peak Security background is intended to reflect the capacity required to meet the peak demand, whilst the Year Round background is intended to reflect the year round congestion costs in the system.

As we have noted in the introductory section of this report we are concerned that NGET has been instructed to reflect the dual criteria that are now embodied in the SQSS as dual backgrounds in the charging methodology.

3.2. Study framework

For the purpose of this study a three bus network has been devised to represent the GB transmission system. Its principles features include the B6 and B15 transmission boundaries that are the most heavily congested of all system boundaries. The study derives a congestion cost duration curve for the system that indicates the degree and duration of the congestion over the 17,520 settlement periods. The study explores the characteristics of the various segments of this curve in detail, and quantifies the share of B6 and B15 congestions in each segment of the curve, and the times when the congestion is mostly likely to occur. For the year round background to create a reasonable surrogate on which to reflect the costs of the system it would be necessary for both boundaries to display a similar representation of the costs of congestion across the year. In fact the outputs from the study clearly indicate that congestion at different boundaries of the transmission network differ hugely in their magnitude, timing, and duration.

The three bus model developed for this study is shown in Figure 12. It represents the GB transmission network as three zones separated by the B6 and B15 boundaries, which together account for more that 80% of all system congestion costs. It thus provides an approximation of the year-round congestion costs in the GB power system. The two boundaries divide GB into three areas; Scotland, England & Wales (excluding Zone 15), and Zone 15.

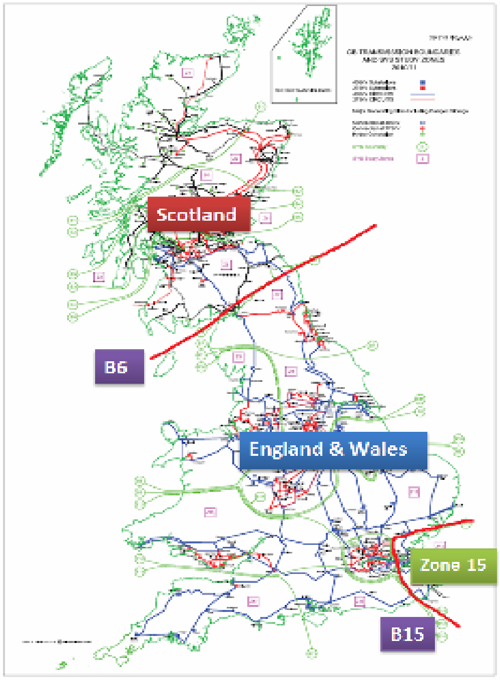

Figure 12: B6 and B15 boundaries in GB power system

The table below shows the parameters chosen to represent the features of the relevant boundaries. These have been taken from the National Grid's ELSI excel document for GB power system in 2011.

Table 5: Three-bus test system parameters

Scotland				B6 Transmission Capacity (MW)	England & Wales (exclude Z15)				B15 Transmission Capacity	Zone 15			
Generation Technology	Price (£/MWh)	Capacity (MW)	Load (MW)		Generation Technology	Price (£/MWh)	Installed capacity (MW)	Load (MW)		Generation Technology	Price (£/MWh)	Installed capacity (MW)	Load (MW)
Nuclear	6.5	2408	5697	2800	Nuclear	6.5	5713	50416	6400	Nuclear	6.5	832	2017
CCGT	39.99	1001			CCGT	45.35	19063			CCGT	43.01	2769	
Coal	37.63	2608			Coal	56.05	14757			Coal	45	2306	
Oil/OCGT	130.14	539			Oil/OCGT	171.17	4241			Oil/OCGT	150	1122	
Intermittent	0.01	2700			Intermittent	0.03	848			Intermittent	0.02	357	
Interconnector	0.01	385								Interconnector	0.001	2401	

The principal assumptions in the model are:

- Six different generation technologies are chosen for each area and the installed capacities scaled to satisfy the system peak without reliance on intermittent generation and interconnectors
- System reserve and generator availability are ignored for the purposes of this model
- The proportion of each generator technology in the total generation capacity is retained with no new capacity contemplated for any generation technology
- Wind generation output follows the historical wind speed data recorded in 2011 by the Meteorological Office
- Interconnector behaviour is simulated as generation and demand as the GB system demand changes. When demand is high (over 80% of peak), the interconnectors are deemed to be unavailable on the basis that other systems will also be experiencing high demand. When the demand is modest from 50% to 80% of peak, the interconnectors operate at their rated capacity as a generator. When the demand is below 50% of peak, the interconnectors are recognised as demand representing the exporting of power at this time
- Maximum transfer capacities for the B6 and B15 boundaries are taken as 2,800 MW and 6,400 MW respectively in accordance with their performance in 2011
- Transmission losses are ignored
- System peak demand of 58,130MW is split across the three zones with Scotland accounting for 5,697 MW, E&W for 50,416 MW, and Zone15 for 2,017 MW
- The demand profile is taken from the GB historical data for 2011 provided on the NGET website, although the same profile is assumed for each zone
- Electricity prices for each generation technology use the typical values in the ELSI excel document, with prices in Scotland and Zone 15 set lower than prices in England & Wales
- The congestion direction on B6 is from Scotland to England & Wales, and on B15 from Zone 15 to England & Wales.

The same methodology as employed for the two busbar model is followed. At times when only B6 is congested the corresponding congestion cost is allocated to B6; similarly with B15. When Both B6 and B15 are congested, the relevant power flows are used to allocate the congestion cost between B6 and B15.

3.3. Congestion cost duration curve

Figure 13 is the congestion cost duration curve derived from the analysis. It is constructed by rearranging the congestion cost observed in each settlement period from the highest to the lowest. Extremely high congestion costs only occur for a very small duration (about 12 hours), after which the congestion cost in each settlement period declines exponentially to zero.

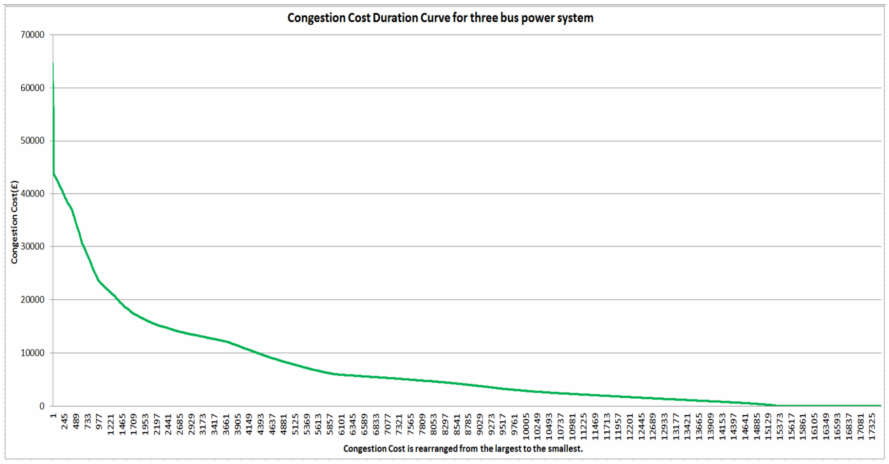

Figure 13: Congestion cost duration curve for three bus power system

The congestion duration curve can be divided into five parts representing a five piece-wise linear curve, as shown in Figure 14. The boundaries between each part are not absolute. For example some settlement periods in part 3 have the same congestion circumstances as in parts 2 and 4. The various parts are characterised by:

- Part 1 covers settlement periods when extremely high congestion costs occur. The range of congestion cost in this period is from £75,000 to £44,000 per settlement period. In these settlement periods, only the B6 boundary is congested
- Part 2 encompasses most settlement periods when both B6 and B15 are congested. The range of congestion cost is from £44,000 to £36,000
- Part 3 includes settlement periods when both boundaries are congested, or when either boundary is individually congested. The range of congestion cost in these periods is from £36,000 to £4,000.
- Part 4 includes mainly settlement periods when B15 is congested, and some when B6 is congested. The range of congestion cost is from £4,000 to £3,000.
- Part 5 includes most settlement periods when B6 is slightly congested.
- Beyond Part 5 there is no congestion for a little over 12% of the year.

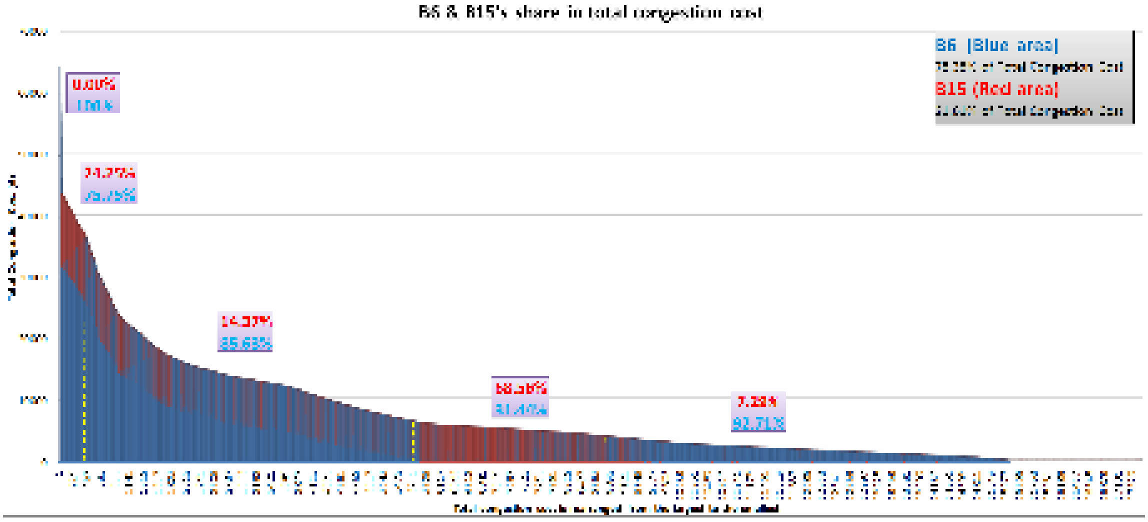

Figure 14: B6 and B15 share in total congestion cost

Table 6: Congestion between B6 and B15 under different part of congestion duration curve

	Number of settlement periods	B6 Congestion Cost £M	B15 Congestion Cost £M	Total Congestion Cost £M	Congestion share between different parts	Proportion of B6 in TCC	Proportion of B15 in TCC
Part 1	23	1.3	0	1,3	1.06%	100.00%	0.00%
Part 2	394	12.0	3.8	15.8	12.87%	75.75%	24.25%
Part 3	5427	67.4	11.3	78.7	63.91%	85.63%	14.37%
Part 4	3042	4.8	10.7	15.5	12.57%	31.44%	68.56%
Part 5	8634	10.9	0.9	11.8	9.58%	92.71%	7.29%
Total	17520	96.5	26.6	123.1	100%	78.38%	21.62%

The above table shows the share of congestion cost between B6 and B15 as determined from the areas under different parts of the congestion duration curve. The overall annual congestion cost described by the model is £123 million.

- In part 1 B6 contributes to all congested periods whilst B15 is not congested
- In part 2 when both B6 and B15 are congested their congestion cost shares are different. B6 contributes 75.8% of the congestion cost whereas B15 contributes only 24.2%.
- In part 3 B6 contributes to 85.6%, while B15 contributes 14.4%.
- In part 4 when B15 contributes to most of the congestion, the position is reversed with B15 accounting for 68.6% of the total whilst B6 accounts for only 34.4%.

- In part 5 when B6 is slightly congested in most of settlement periods, B6 become dominated again at 92.7% of the total.
- Overall the B6 boundary incurs 78.4% of the total congestion cost, and B15 21.6%.

The different parts of the congestion cost duration curve reflect different congestion scenarios. Under different scenarios, the role of the same generator may change. A generator which contributes to congestion within one scenario may help eliminate congestion in another scenario. Even for the simple three bus representation of the GB transmission system it is necessary to have at least five different congestion periods to reflect the various aspects of year round congestion. The inevitable conclusion is that employing only two backgrounds is wholly inadequate in producing even the crudest representation of system performance and costs.

3.4. The nature of boundary congestion

The following figures explore the intensity, location and timing of congestion costs as derived from the 3-bus model. The first figure is a plot of congestion cost for each settlement period from 1st Jan 2011 to 31st Dec 2011, and the second indicates the same picture but as a scatter diagram to separate the various points. A colour code is used to distinguish periods when only the B6 boundary is congested (blue points) from times when only the B15 boundary is congested (red points) and times when both boundaries are congested (green points). In general the congestion across the B6 boundary is significantly higher than across the B15 boundary. These diagrams illustrate that congestion is not uniform across the system.

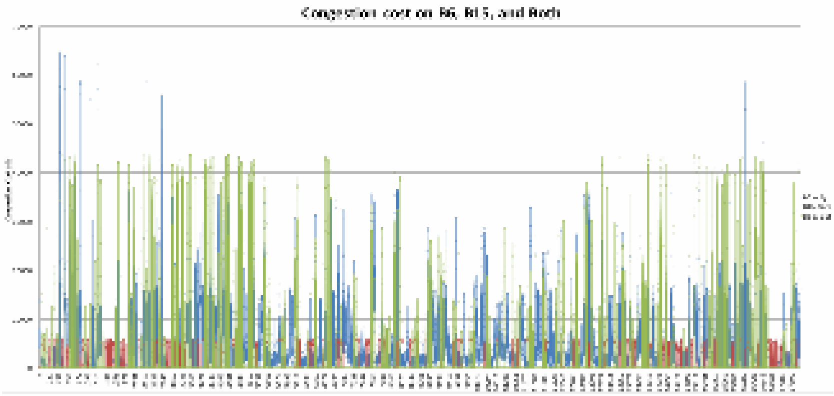

Figure 15: Year round congestion cost over the system

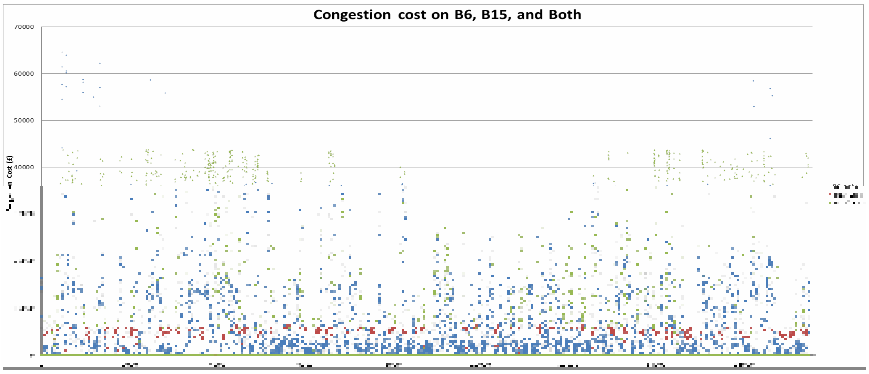

Figure 16: Scatter plot of year round congestion

The following three figures further illustrate the diversity in the timing of the congestion periods during calendar 2011 by indicating the times of congestion at the B6 boundary, the B15 boundary, and when both boundaries are congested.

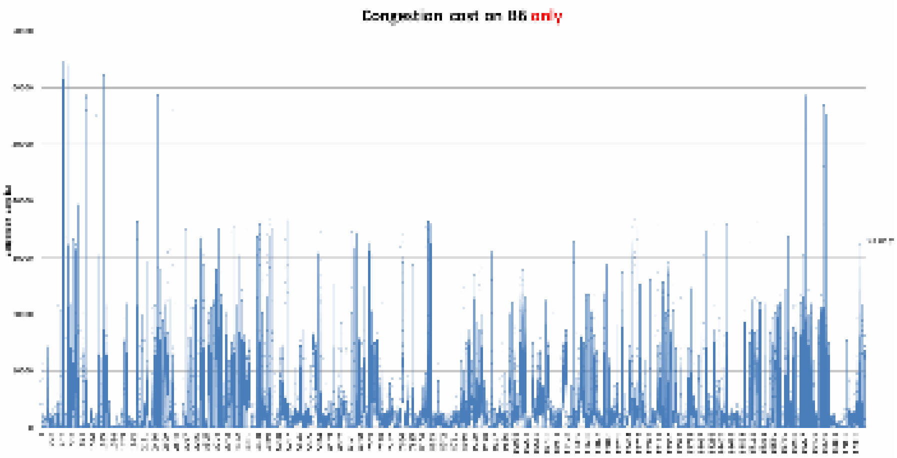

Figure 17: Year round congestion on B6 only

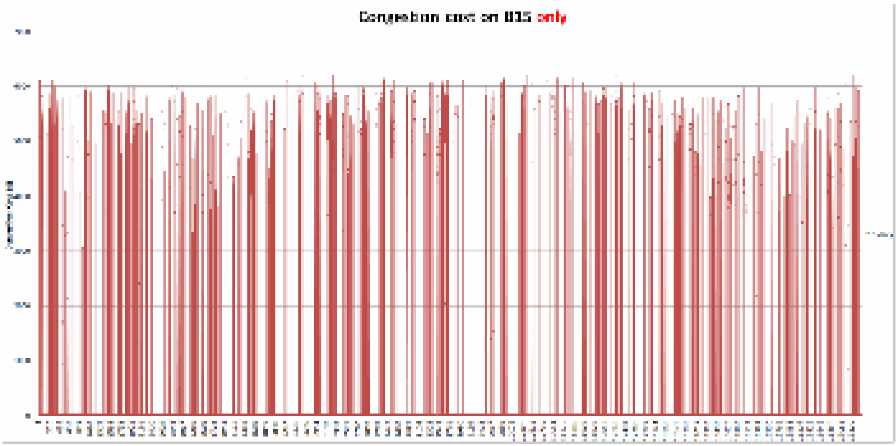

Figure 18: Year round congestion on B15 only

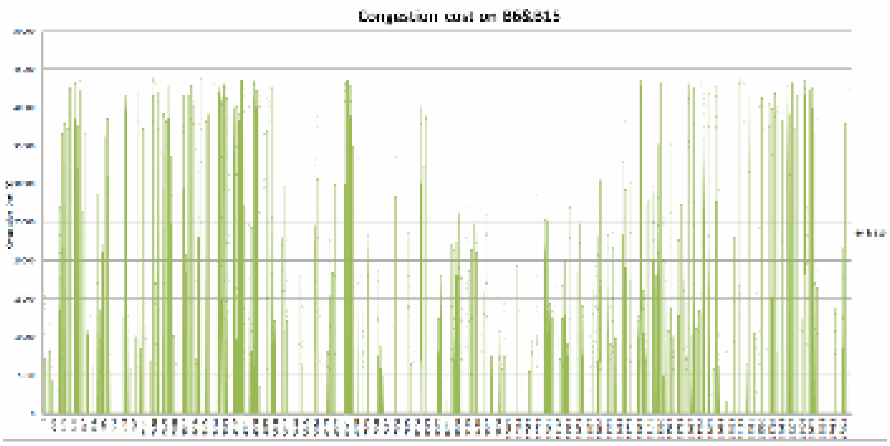

Figure 19: Year round congestion of B6 & B15 together

The proportion of time the boundaries are congested, either singly or together are tabulated below. The probability that congestion will occur on a 3-bus representation of the GB system is 87.8%, although the B6 boundary is responsible for more than 80% of this figure.

Table 7: Proportion of time each boundary is congested

Congestion situation	Number of settlement periods	Proportion in all settlement periods	Proportion in congested settlement periods
System	15,379	87. 8%	100.0%
B6 Only	11,018	62.9%	71.6%
B15 Only	2229	12.7%	14.5%
B6 & B15	2132	12.2%	13.9%

3.5. The timing of congestion

The next five figures explore the frequency and time of day when congestion is arising at each boundary, or combination of boundaries, for each part of the congestion cost duration curve shown in Figure 1.

Figure 20: Part 1 - Frequency and timing of congested settlement periods

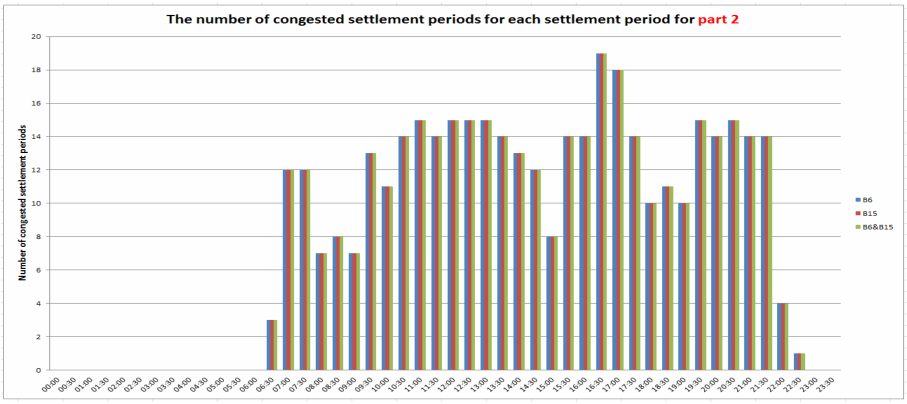

Figure 21: Part 2 - Frequency and timing of congested settlement periods

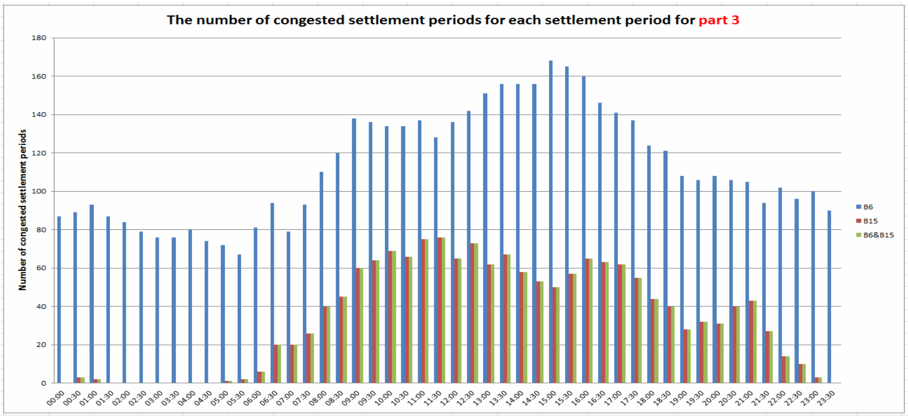

Figure 22: Part 3 - Frequency and timing of congested settlement periods

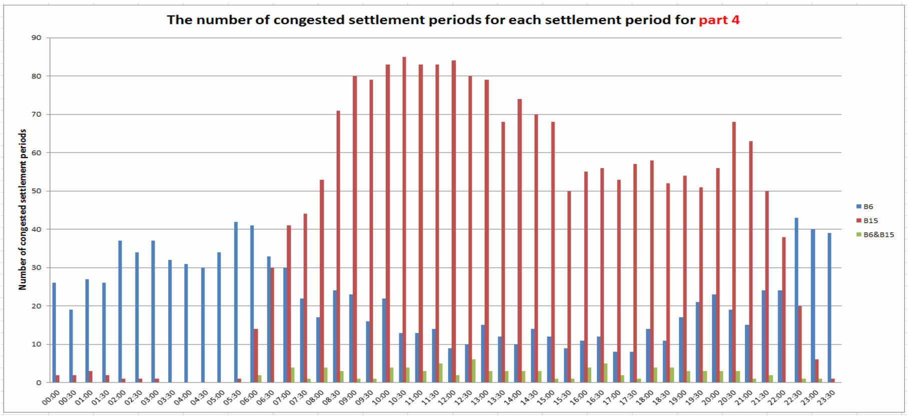

Figure 23: Part 4 - Frequency and timing of congested settlement periods

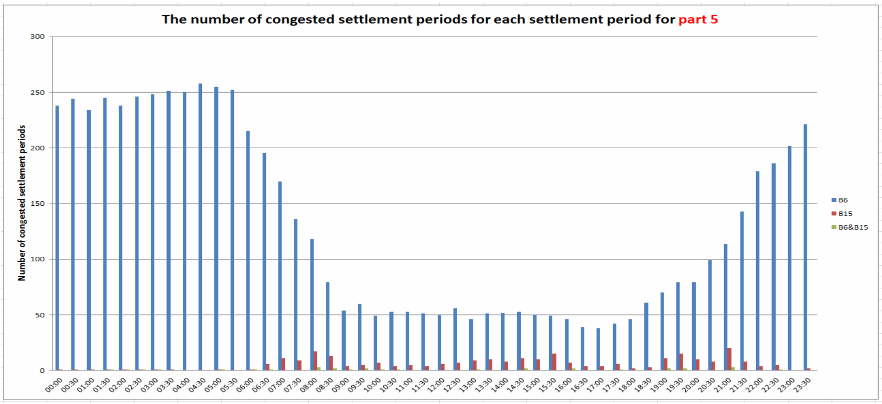

Figure 24: Part 5 - Frequency and timing of congested settlement periods

Part 1 of the congestion cost duration curve demonstrates exceptionally high levels of cost but these are focussed into the six settlement periods around the system peak. They are associated exclusively with the B6 boundary.

In part 2 of the congestion curve, when both boundaries are congested the timing of the congestion becomes more diffuse but is still associated with the day time and evening hours.

Over part 3 of the curve the frequency of congestion on the B6 boundary tends to appear like the typical daily load curve, whereas the B15 boundary is only congested during daytime and evening hours as it was in part 2. When B15 is congested then B6 is generally congested also. The B15 congestion may be affected by the interconnector assumption which is assumed to be exporting power when demand is high.

During part 4 of the curve the B15 boundary shows the same pattern of congestion as for part 3 but the B6 boundary becomes congested mainly during off-peak hours. The incidence when both boundaries are simultaneously congested becomes relatively small.

Finally in part 5 of the curve the congestion of the B15 boundary falls away. The predominance of congestion across the B6 boundary now migrates to the off peak settlement periods.

3.6. Conclusions

In this section, we have illustrated that year-round congestion costs is not uniform across the system but varies significantly in magnitude, time and boundary location. These differences in congestion magnitude, time, and location are not reflected in the CMP213 proposals. Rather, the use of a single year-round scenario at the time of peak generation outputs and annual load factor to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout the year. Employing load factor as a surrogate for the cause of congestion would smear the consequence for one boundary across all boundaries and in all time periods. It cannot provide the necessary economic message for reducing congestion, and it certainly will not reflect the costs of congestion in accordance with SLC 5.5. The inevitable consequence of adopting the IICRP proposals is a further increase in congestion cost, which is in direct opposition to the purpose of project Transmit.

An arrangement that could target TNUoS charges and credits in periods and locations where generator output either contributes to, or relieves congestion would be a constructive approach. However, this implies a time of use feature in TNUoS charges that is developed against multiple backgrounds rather than simplistically linking it to generator annual load factors.

However if multiple background with their respective time periods and duration are judged to be too complicated then the existing ICRP method should be retained for the sake of ease of understanding rather than further dilute the economic signal. This would be a better solution that would accord with the principles of cost reflection, rather than creating a dual background which would be a retrograde step in the reflection of costs and the provision of useful economic signals.