How do Constraint Costs flow into Transmission Charging Methodology

Introduction

As part of CMP405, it may be beneficiary to revisit how and why, the current TNUoS charging methodology was created and why it was originally changed as part of Project Transmit, as well as the key rationale behind the different aspects and concepts of the methodology.

Throughout this document I have aimed to be as objective as possible using public presentations, consultation documents and decisions from National Grid at the time and Ofgem, so as to avoid obvious bias as the Proposer of this Modification.

Timeline

GSR-009 (2011)

The proposal GSR009 was raised to amend Section 4 of the SQSS (and associated appendices), which outlines the assessment of minimum transmission capacity requirements. The proposal recommended a 'dual criteria' approach which incorporated both demand security and **economic criteria** to be considered in the development of the transmission network. Each of these criteria would include specific assumptions about different types of generation, including intermittent generation.

The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met without intermittent generation. The Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The proposed approach involves a set of deterministic parameters which have been derived from a Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between the constraint costs with the costs of transmission reinforcements.

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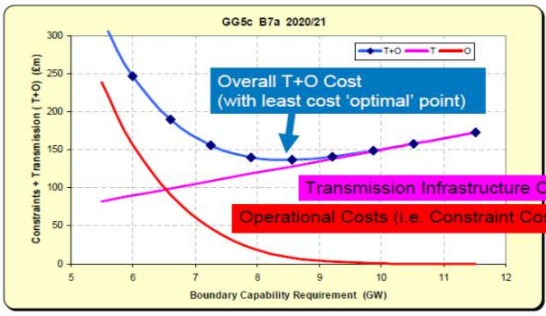
GSR-009: Review of NETS SQSS for Intermittent

- Total transmission cost = operational + infrastructure



- GSR-009 set out to create deterministic standards from detailed cost-benefit analysis (CBA)

It's clear that Operational costs play a clear and obvious role in determining whether new Transmission Investment is required or not. The SQSS feeds into the NOA process. This uses a market model to determine the likely costs of Constraints at particular boundaries on the system. When Operational Costs reach a particular level, it becomes more cost effective in terms of overall Transmission Costs to build new Transmission Infrastructure. This will trigger a go ahead scenario for new Transmission Investment. The constraint does not need to be relieved in full. Any reduction in Operational costs reduces the need for Transmission Investment

The Scaling Factors used in the Transport model and the SQSS aim to replicate that ‘sweet spot’. The economy scenario is only ever a proxy. Actual CBA’s will be carried out before new Transmission Investment is approved and built (or an equivalent non build option).

The sweet spot of various levels of Generation of varying technologies to serve Peak Demand is illustrated below.

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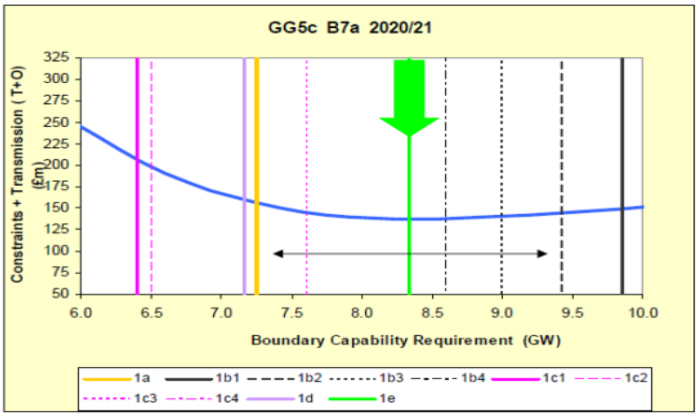
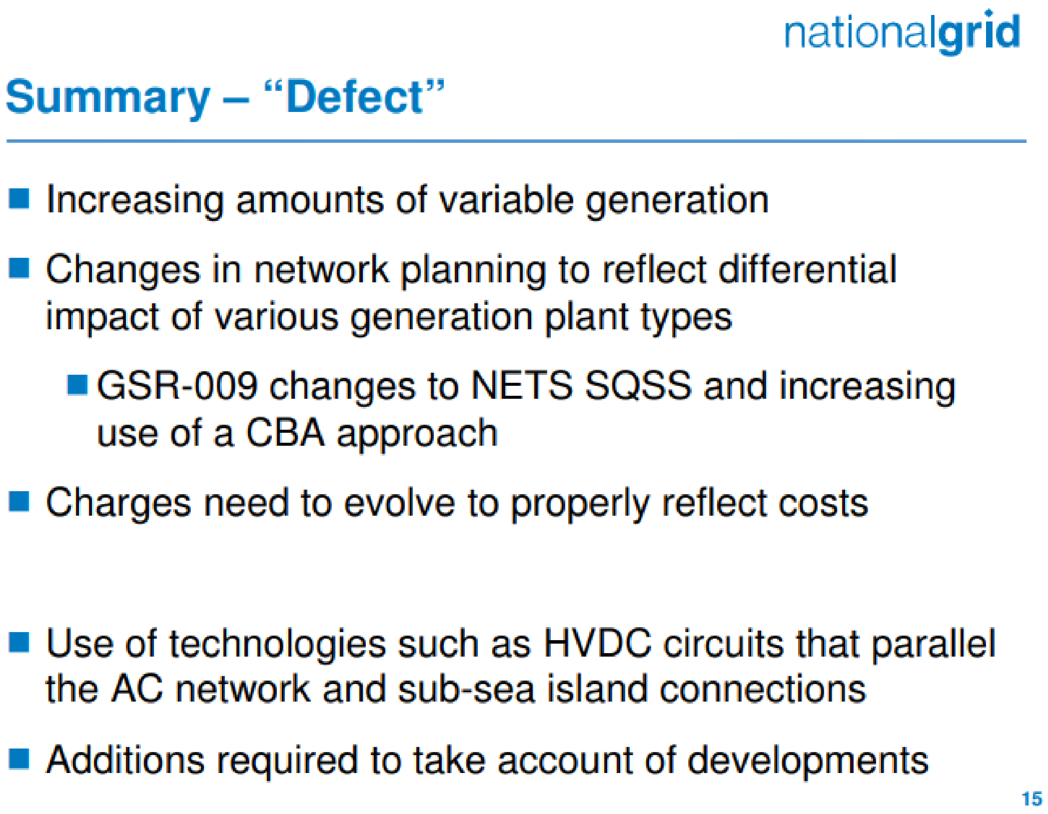
GSR-009: Review of NETS SQSS for Intermittent



- Various approaches to the grouping and scaling of generation to meet peak demand investigated
- Address both demand security and CBA requirements

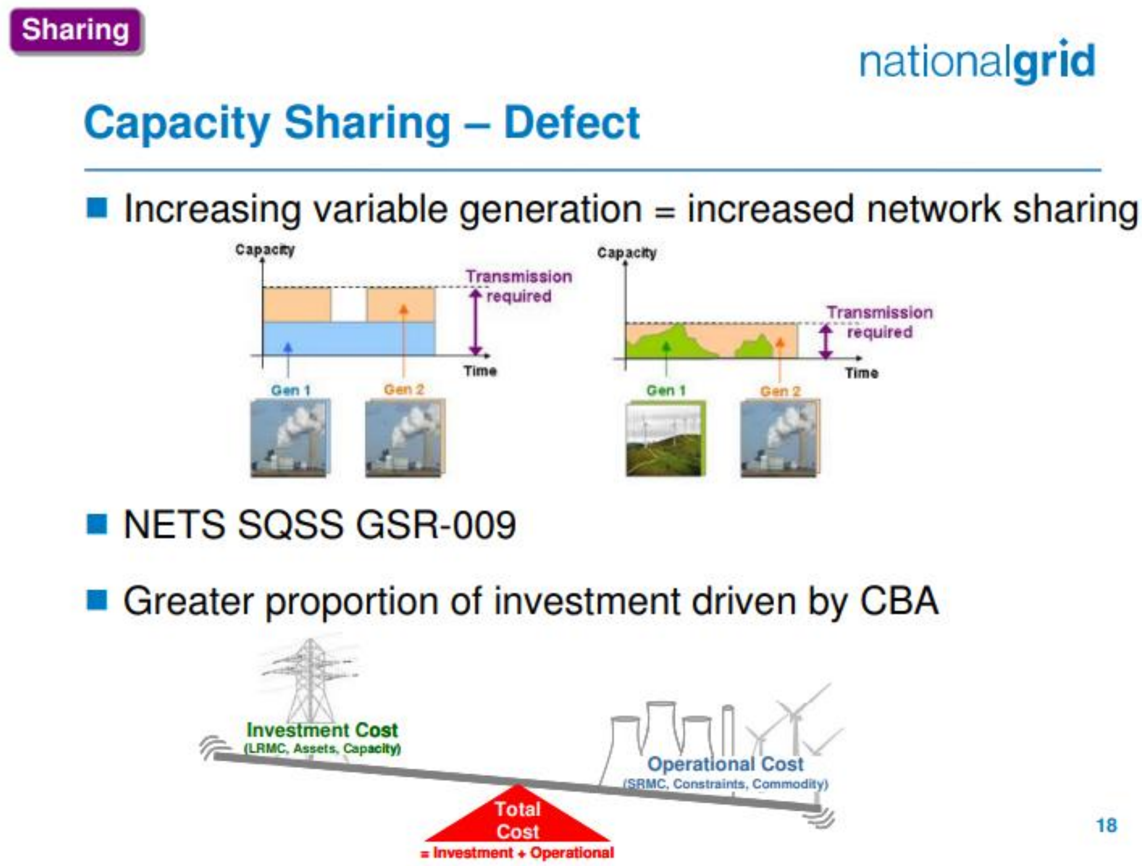
Project Transmit

Previously all Generation was treated the same and resulted in inefficient transmission build and TNUoS tariffs which did not reflect the actual impact different types of Generation had on the system. The increased connection of intermittent as well as the introduction of GSR-009 necessitated Project Transmit to also alter TNUoS tariffs

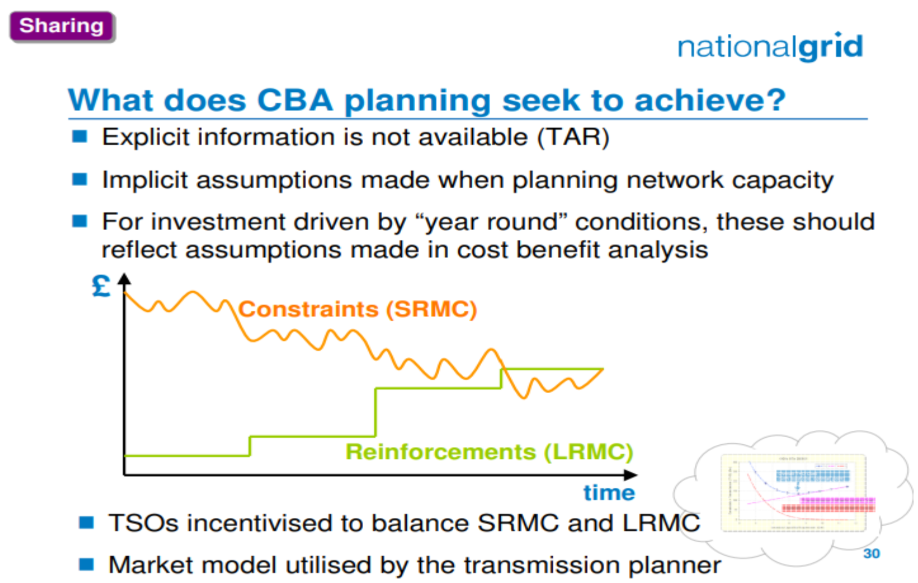


The above slide discusses the defects which Transmit aimed to address a high level. It is important to understand the defect and the building blocks of the current methodology as lots of the rationale behind the TNUoS methodology can also be replicated for CMP405.

The following slide highlights how the Economy background works. Again, it clearly shows that Operational Costs and their magnitude over the long term is a clear determinant of the need or not for new Transmission Investment.

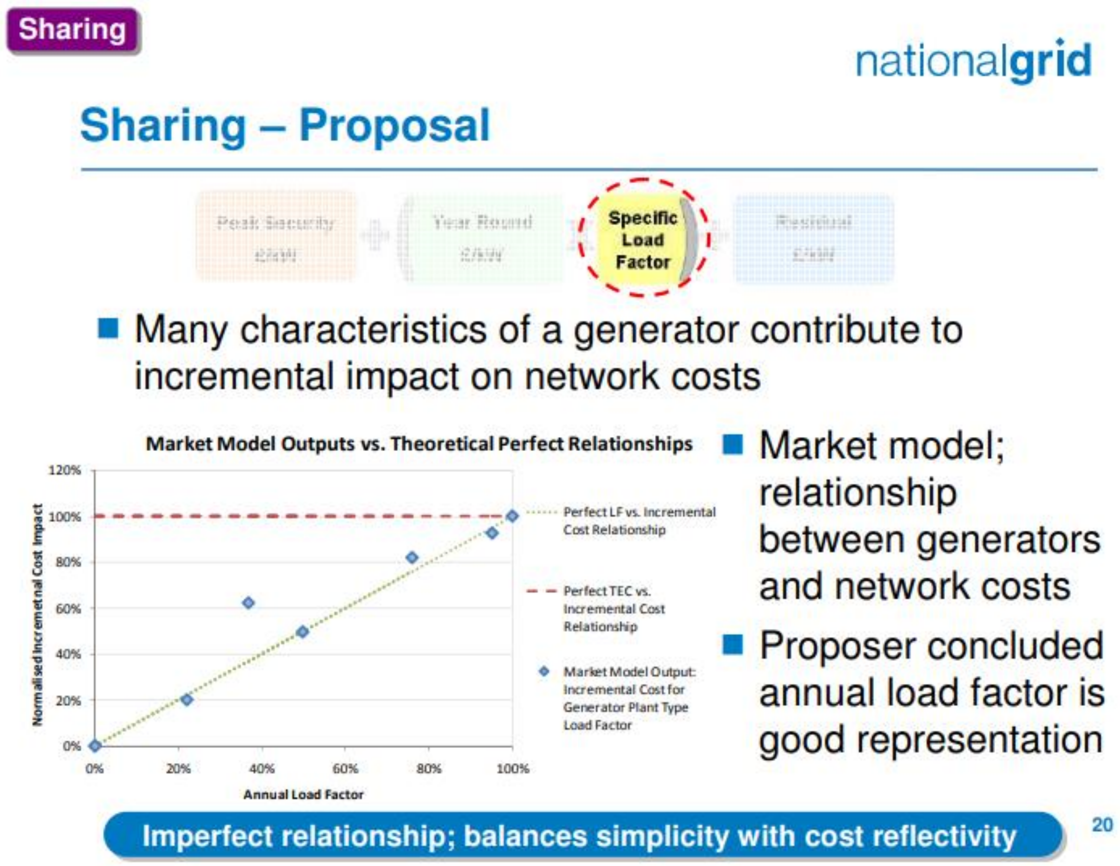


The aim of Transmit was to change the charging methodology so as to reflect how a CBA operates. Use of System Charges should as a proxy reflect actual investment.



Sharing

Different types of generation do not all operate at the same time, so can share the same network. Under the previous charging methodology all Generation was treated the same and was assumed to all operate at the same time to meet Peak Demand. When all Generation is dispatchable that is the case as they are incentivised to chase the wholesale price, but intermittent renewables are different because they operate when the 'fuel' is available. *The term dispatchable could be considered as a reasonable rationale for initially restricting the modification to Storage which has a contract with National Grid (i.e. can be dispatched through the BM) and not all demand. Year Round Tariff for Generation is based on the relationship between constraints costs and the market model.*



Components which create constraints

The following slide shows the different components which create constraint costs. It may also help the thought process when creating potential solutions by reversing the components.

i) import volume over the year points to a demand credit of at **least** ALF. ALF was deemed a reasonable proxy for Transmission Investment. However Storage is incentivised to correlate importing with high wind. It may export at times of high wholesale prices at similar times to wind. However the Generation charges cover these scenarios.

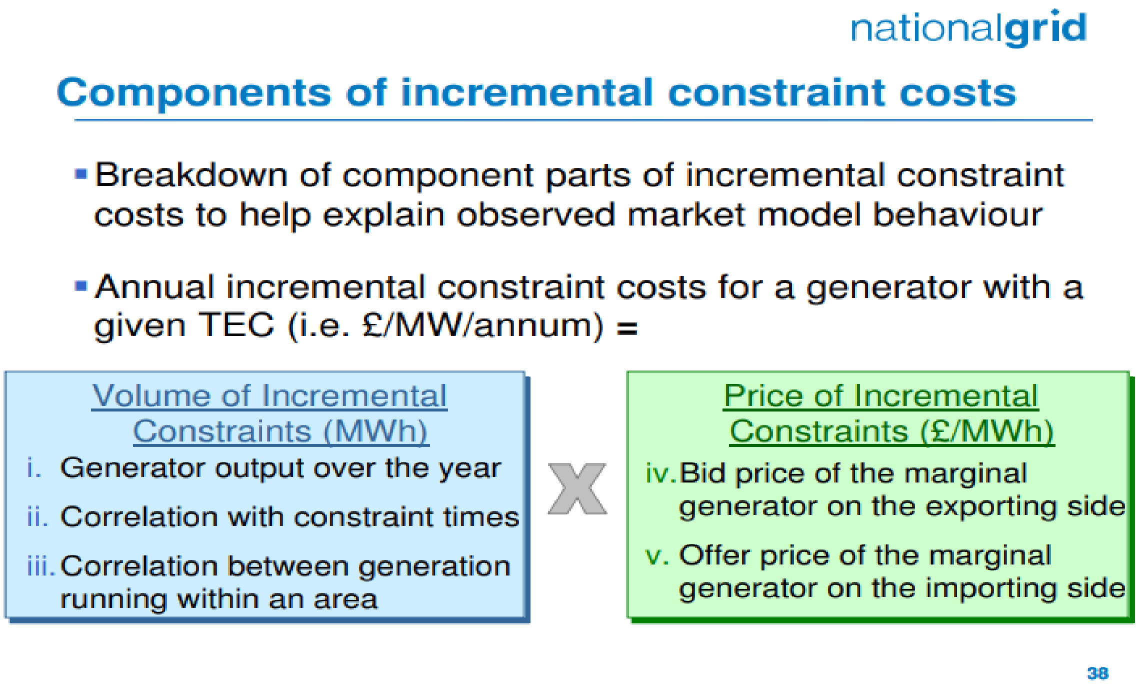
ii) correlation with constraint times - High correlation with periods of constraint points to demand credit greater than ALF and closer to 100% capacity. Pumped hydro will either FPN to pump, or can be dispatched to pump in the BM at times of constraint

Iii) pumped hydro pumping will tend to be correlated with wind generation within an area, especially as more wind connects pushing the wholesale price down

Prices

Bid price: Pumped storage (should) provide cheap bid price to pump in the BM.

Offer price: Storage is cheaper than it may initially seem on the BM because, although ESO still needs to "offer" on another generator on the opposite side of the constraint in that HH, the stored energy can displace a different unabated thermal generator at a different time, hence reducing total system cost. This is something which may not be currently calculated in any benefit analysis if only the Settlement Period in question is looked at, and not future Settlement Periods.



Use of Peak Demand

Wind which received subsidies under the ROC regime are incentivised to generate even if the wholesale power price is negative up to the value of their support payment. However, for longer periods of negative prices which is likely to become increasingly more common the support is removed for these lengthy periods. With Merchant wind and newer CfD wind with lower strike prices, that incentive to generate at times when the wholesale power price is negative is less is removed.

Arguably, the locational signal and subsequent benefit for Storage, may actually be on the low side due to the use of Peak Demand. Any additional scenarios which use a lower demand in the DCLF model will result in the current year round negative locational signal becoming even more negative. Storage is therefore potentially being under-rewarded as opposed to overrewarded by the use of Peak Demand, but introducing a credit via this modification is still better than the current baseline from April 23. This rationale may help to ease any fears that the benefit is not cost reflective from an over rewarding perspective.

As more and more wind connects to the System over time, the a low demand scenario is likely to become less viable as a Scenario to worry about from a Transmission Investment perspective. At low demand levels, merchant wind and those with CfDs will be incentivised to switch off without being constrained off due to the negative wholesale price. All this naturally caps the negative locational signal as high wind generation output with low demand is not a feasible scenario going forward. This potentially reduces concerns around the use of Peak Demand in the model for the purposes of this modification.

Selection of quotes from Consultation Documents

[Further Consultation on proposals to change the electricity Transmission Charging Methodology]

This quote comes from Ofgem during Project Transmit;

"We consulted on proposals put forward by industry in August 2013. These addressed defects in the existing transmission charging arrangements. At that time our minded to position was to approve the "Workgroup Alternative Connection and Use of System Code (CUSC) Modification 2" (or WACM 2) option and to implement this in April 2014. We continue to think that WACM 2 best addresses the identified defects, and therefore remain minded to approve it. This is because it reflects the costs imposed by different types of generators on the electricity transmission network by:

- *Splitting the tariff into two components. This aligns with the assumptions in the transmission planning standard and the drivers of transmission investment.*

- *Recognising the link between the constraint costs triggered by a generator and the level of transmission investment triggered.*

- *Recognising that areas with high concentrations of low carbon generation are less able to efficiently share transmission capacity. This is because low carbon generators are more expensive to constrain off (due to interactions with government renewable energy support policies) and are more like to generate at the same time resulting in higher constraint costs. So it is efficient to build more transmission capacity for such areas.*

Transmission investment decision process

For charges to be cost-reflective, the calculation of the incremental impact that a generator has on the system used in the charging methodology should reflect the transmission investment decision-making process and the drivers of transmission investment. This is governed by the Security and Quality of Supply Standards (SQSS) which sets out the minimum criteria that the Transmission Owners (TOs) must comply with when determining the required capability of the transmission network (known as the Main Interconnector Transmission System (MITs)).

The growth in intermittent generation connecting to the transmission system has changed the nature of investment planning. Traditionally, this has been driven by the need to ensure peak security in an environment dominated by conventional generators. However, intermittent generators cannot be relied upon to be operating at peak demand. In addition, increasing intermittent generation has given rise to investment planning now being driven to efficiently managing constraint costs.

The SQSS was updated to reflect this shift in 2011 to include two sets of criteria setting out the assumptions to be used when assessing the required level of capacity.

TOs must build transmission capacity determined by the following two conditions:

- *Demand Security criterion – the minimum transmission capacity required to ensure that conventional generators can meet demand at times when intermittent generators cannot run (ie there is no wind).*

- *Economy criterion – the additional transmission capacity needed above that to meet peak demand to efficiently manage the system taking into account the need to manage constraint costs in an effective and economic manner.*

We share this view. NGET's analysis (presented in Appendix 4 to the FMR) shows that generally generators with a higher output have a bigger impact on constraint costs. This relationship is not always perfectly correlated and is more pronounced in some zones than others. The assumption through the use of ALF in WACM 2 of a perfectly linear relationship between output and constraints is therefore a simplification. However, the status quo does not recognise this relationship at all.

In addition, by splitting the Year Round tariff into 'shared' and 'non-shared' elements, WACM 2 also recognises that the mix of plant in an area will have an impact on the level of constraint costs. This is because, in zones dominated by low carbon plant, these generators are less able to efficiently 'share' transmission network capacity because they tend to run simultaneously (eg when the wind is blowing). They are also expensive to constrain off compared to other forms of generation. Constraint costs will therefore tend to be higher in zones with high concentrations of low carbon plant. The non-shared element of Year Round tariff therefore increases as low carbon plant exceeds 50% in a zone and is not adjusted for ALF in recognition of this effect.

We therefore consider that WACM 2 is an improvement on the existing charging methodology. It represents a simple, transparent proxy for the impact of a generator on constraint costs, and therefore on transmission investment, taking into account the mix of generation in an area. However, it will not precisely reflect the impact a generator has on transmission investment in every circumstance, especially at the extremes, for example, when there is 0% or 100% of a particular type of generator in a zone. A more accurate calculation that captured all the factors that affect investment decision-making would require considerably more complexity. We think this would make the charging methodology less transparent and more difficult to forecast. We consider that this would be a barrier to entry, reduce competition and would offset any gains from the additional precision. It will never be possible to exactly capture the impact of an individual generator on the system while remaining within the principles of the ICRP methodology. ***Balancing accuracy with the simplicity and transparency of tariffs is an important part of the ICRP methodology because of the impact these factors have on competition.***

I have highlighted this particular part of the quote as it's important to consider when choosing potential solutions. T

[Decision on proposals to change the electricity Transmission Charging Methodology]

This quote again comes from Ofgem during Project Transmit;

"The change under WACM 2

WACM 2 would split the TNUoS tariff for generators into two parts:

the Peak Security tariff and the Year Round tariff. Only conventional generators would be charged the former but all generators, including intermittent ones, would be subject to the latter. This aligns to the transmission planning standard and reflects the fact that intermittent generators are not assumed to contribute to meeting peak security. In its power flow model used to calculate tariffs, National Grid would split the circuits between the two tariffs using similar assumptions to those in the transmission planning standard. There would also be two further adjustments to the Year Round tariff. The first of these is to split the tariff into two elements: 'shared' and 'non-shared.' This refers to generators' ability to 'share' transmission capacity which depends on the concentration of types of *generators in a particular area. It recognises that it is efficient to build more transmission capacity for areas with a high concentration of low carbon generation because this type of plant is likely to be generating at the same time (ie when the wind blows) and is expensive to constrain off. Once the proportion of a low carbon generation in an area exceeds 50%, then part of the Year Round tariff will be classed as 'non-shared'. The proportion of the Year Round tariff that is non-shared will increase as the percentage of low carbon generation increases. The second adjustment is to adjust the 'shared' element of the Year Round tariff by a generator's average annual load factor for the last five*

years (with the highest and lowest years discarded). This recognises that there is a link between the level of constraint costs triggered by a generator and the level of transmission investment."

CMP268: 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

This quote comes from Ofgem in their decision letter approving modification CMP268;

"As part of the changes brought in by CMP213 (Project TransmiT), the Wider Generation TNUoS charging methodology ("the charging methodology") recognises that different types of generators impose different costs on the transmission network.

Post-CMP213, the charging methodology was required to reflect that system investment and operation has to efficiently balance longer-term costs, such as the use of infrastructure investment, with short-term network costs through system operation, such as constraining off generators. It also recognises the costs of meeting the needs of the system under different supply scenarios. This change was seen to provide a better representation of the drivers of transmission investment than the then status quo, because it more closely aligned the charging methodology to the transmission investment decision making criteria."

Conclusion

The current charging methodology and the Year Round Tariff purposely reflects Operational costs and aims to be a proxy of the Transmission Investment process.

The locational signal for Demand builds on this thought process. Increased demand in these areas reduces Operational Costs, therefore the requirement for new Transmission Investment.