

Briefing Note

CMP 432 – Issues with the locational onshore security factor methodology



IMPORTANT NOTICE

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Key Points

The current methodology for setting the locational onshore security factor appears to be inconsistent with the economics of developing the GB transmission system.

- The current methodology is based on the additional transmission capacity required to cater for incremental generation on a secured system basis relative to that without considering potential circuit outages. The estimation is made on a node by node basis to derive a relationship between secured and unsecured required transmission.
- For each node the additional transmission required on an unsecured basis is estimated, i.e. without considering possible circuit outages, and then the additional transmission required is estimated taking into account that spare transmission capacity is required such that the incremental generation can reach demand even if one of the circuits fails. The incremental generation is assumed to increase the loading on the existing lines, which effectively requires spare capacity to be scaled up as well to cater for a circuit loss.
- This seems to miss some key realities of the GB transmission system, particularly the future GB transmission system.
 - I. The addition of transmission capacity is primarily through the addition of new circuits rather than the continued increased loading of existing circuits.
 - II. The addition of incremental generation to an 'intact' system with no transmission redundancy is an irrelevant consideration, the system is already secured.
 - III. On a secured system the requirement for spare transmission capacity arising from the activities at different nodes is not independent. Once spare capacity across a transmission boundary is available to cater for generation at any node, that spare capacity is also available to cover the generation from other nodes.
- Taking these into account fundamentally changes the need for additional spare transmission capacity as load across a transmission boundary increases.
- The development of additional transmission capacity to cater for wind generation is based on a cost benefit analysis that leads to a deliberate undersizing of transmission relative to maximum potential power flows. There is therefore an argument for a less than 1 LSF for windfarms.

Introduction

Within the Investment Cost Related Pricing methodology used to set transmission use of system charges in the GB market, a multiplier called the locational security factor (LSF) is used to increase transmission charges to reflect an assumed level of transmission redundancy.

SSE considers the LSF currently applied to be excessive and has proposed, in code modification CMP 432, that the locational security factor be reduced from 1.76 to 1.

This briefing note, prepared by and reflecting the views of Neil Cornelius and commissioned by SSE, discusses potential issues with the LSF methodology and modelling currently carried out in the context of GB transmission system economics and development.

The locational security factor

The Locational Security Factor (LSF) is applied to the required MWkms estimated in the ICRP Transport model. It is intended to reflect the required transmission system redundancy to maintain resilient network operations against potential circuit failure. The National Grid guidance to generators explains that the LSF:

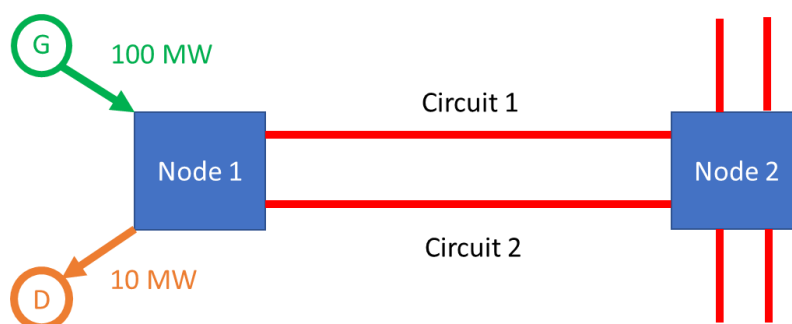
“is required to take into account the additional redundancy that is built into the network through the obligation on the TOs to meet the SQSS requirements, and to accommodate flows under both planned and unplanned circuit outages”

The LSF is applied uniformly to the marginal MWkms calculated at each node on the system in the transport and tariff model. The intent is that the ICRP sets charges that are cost reflective, as noted in the CUSC:

“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.”

For the LSF to be appropriate it must therefore reflect the actual redundant transmission capacity required in response to incremental generation at each node.

In the 'Guidance on TNUoS Locational Onshore Security Factor Calculation' issued by National Grid ESO in December 2020, the derivation of a nodal LSF is illustrated using the following example of a simple intact network. Each circuit is 10 km long and node 2 is assumed to have a large load.



On this network, an incremental MW of generation at node 1 would require 10 MWkm of additional transmission on the intact network to reach the demand at node 2 (in the National Grid example evenly split between circuits 1 and 2). However, due to the possible loss of one of the circuits, a secured network requires both circuits to be expanded by 10 MWkms such that the incremental generation can be accommodated on either line in the event of the other failing. The LSF is calculated as the ratio between the additional MWkms on the intact circuit and those on the secured network, in this case the LSF would therefore be 2.

National Grid use a secured DCLF model to assess the LSF for each node on the system using this methodology, the overall LSF is then set by a regression analysis of the nodal observations of intact MWkms versus secured MWkms. The resulting value is currently 1.76 with the regression analysis reporting a R^2 of 99.5%.

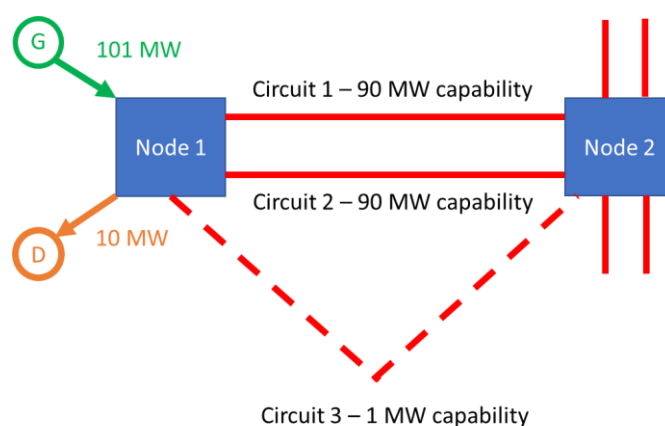
Issues with the current LSF methodology

The LSF methodology fails to take into account three linked realities of current GB transmission development:

- 1) The addition of transmission capacity is primarily through the addition of new circuits rather than the continued increased loading of existing circuits.
- 2) The addition of incremental generation to an intact system with no transmission redundancy is an irrelevant consideration, the system is already secured.

- 3) The LSF methodology assesses the LSF node by node before using a regression analysis to derive a best fit relationship between unsecured and secured MWkms. However, on a secured system the requirement for spare transmission capacity arising from the activities at different nodes is not independent. Once spare capacity across a transmission boundary has been determined to cater for generation at any node, that spare capacity is also available to cover the generation from other nodes.

To demonstrate the overall effect of these issues, I adapt the National Grid schematic below:



Circuits 1 and 2 are each sized to 90 MW to provide security for the initial 90 MW flow from node 1 to node 2. The incremental generation at node 1 is then catered for by an additional 1 MW capability circuit from node 1 to node 2 (more realistically a 90MW increment of generation matched by a 90MW additional circuit could be considered). There is no requirement for additional security, the loss of circuit 3 can be easily catered for by circuits 1 and 2 which already have spare capacity of 90 MW. The incremental generation is therefore catered for by 10 MWkms on the secured system, the same as for the intact system in the National Grid LSF methodology, implying a LSF of 1 with the recognition of additional circuits.

The maps below show the GB transmission reinforcement determined by the Holistic Network Design Follow Up Exercise and the Beyond 2030 transmission plan. These show the extent to which GB transmission development, particularly future grid development, is achieved through multiple additional transmission lines across the key transmission boundaries.

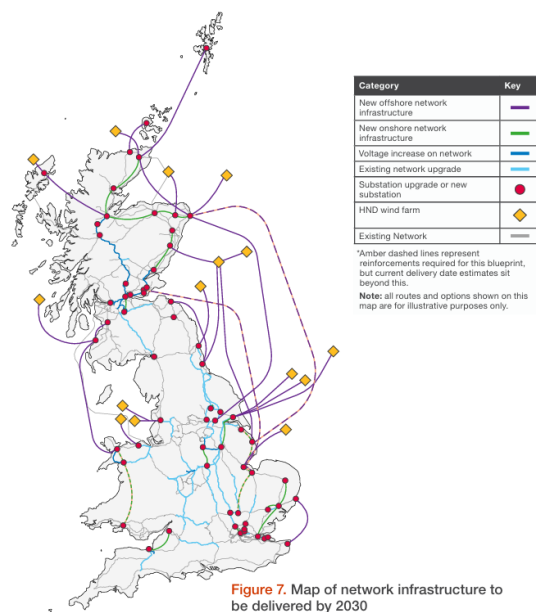


Figure 7. Map of network infrastructure to be delivered by 2030

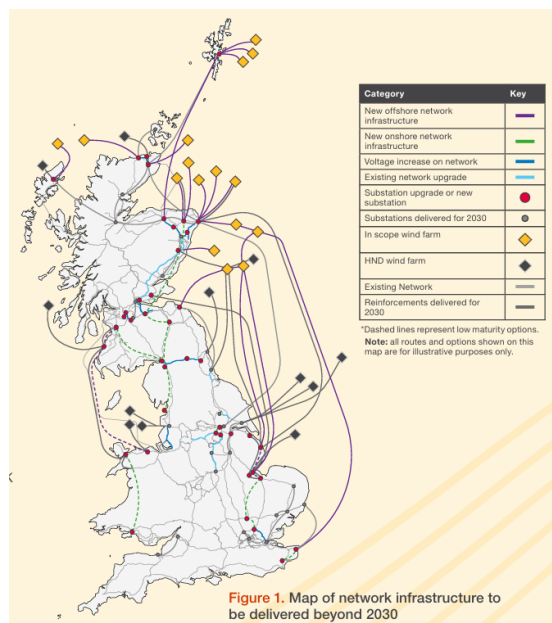


Figure 1. Map of network infrastructure to be delivered beyond 2030

If an LSF of 1.8 is appropriate, we would expect actual boundary transfer capacities to increase at a rate significantly below the rated capacity of lines added (at 55% of line capacity), however this does not seem to be the case. The change in the boundary capability resulting from new transmission lines is a complex relationship varying according to individual circumstances. Some examples, from the 2016 Network Options Assessment 2016 NOA), are:

- Western Link - the increase in boundary capability is actually greater than the line capacity for some of the boundaries crossed, presumably due to the impact of the new link on the pattern of flows on the existing network and an ability to flow more power through the pre-existing lines. The 2016 NOA states that the boundaries affected by the 2200 MW link would be B6, with a 2200 MW increase in boundary capability, B7 with 2500 and B7a with 2830.
- Eastern Link - the contribution to boundary capability varies across boundaries affected. The 2000 MW link is suggested to provide the following additional boundary capability; B2 (300), B4 (1360), B5 (2000), B6 (2010), B7 (620), B7a (360). Of these the link doesn't actually cross B7 or B7a, terminating at Hawthorne Pit north of B7. The ratio of increased boundary capability to line rating is therefore 1 for B5 and B6. It is greater than 1 for B2 and B4, however, in overall transmission capacity added terms this will be largely offset by the increased capacity across B7 and B7a which the link doesn't actually cross.
- Hinkley Point to Seabank – this was developed as a double circuit because additional redundancy was required due to the special case that the connection capacity of Hinkley exceeds the largest infeed loss threshold. Reports suggest a capacity of $2 \times 3200 \text{ MW} = 6400 \text{ MW}$, with a boundary transfer capability contribution of 3760 MW.
- Hawthorne Pit reinforcements – option ELEU from the 2016 NOA, shows an example of the boundary capability for B6, B7 and B7a being improved by 600 MW, 1090 MW and 650 MW respectively, by a local reinforcement that doesn't actually cross any of the listed transmission boundaries.

These examples suggest that local network issues can prevent the full capacity of new transmission lines from adding to boundary capability, however this seems to be particularly the case where the existing network capacity is small relative to the scale of the new transmission being added, as in the northern boundaries for the Eastern Link and the Hinkley to Seabank circuit. The Hawthorne Pit example shows that future reinforcement of the local network could increase the proportion of existing cross boundary transmission capacity that can be used, which indicates that the LSF across a particular boundary could decrease over time even if the initial LSF is greater than 1.

A LSF of 1.8 appears to be consistent with a case such as Hinkley – Seabank where full additional redundancy is required. The Eastern Link and Western Link examples show a LSF of 1 or lower where an additional line is added between zones with strong existing networks. Given the planned developments of the GB power system, that will increasingly be the case for new transmission lines which will be increasing capacity where significant capacity and redundancy already exists.

The variation in the circumstances of different zones and boundaries suggests that it may be more accurate to use a local LSF, however whether or not this is a better solution than a generic LSF of 1 will depend on the following factors:

- Incremental MWkms should be based on influenceable transmission investment decisions. It is known that there will be significant strengthening of many transmission boundaries under CP 30 and linked plans, therefore the incidence of transmission boundaries with limited baseline connections will reduce dramatically.
- The materiality of local network conditions may be small relative to the overall incremental MWkms. As an example, the incremental transmission for a windfarm in northern Scotland may include redundancy on local boundaries, but not for many of the boundaries between mid-Scotland and the southern demand zones.
- The complexity of local conditions, interacting with factors such as those discussed above, will increase the costs and challenges of deriving and forecasting LSFs. These will also change as the system evolves if they reflect the system reality and it may be hard for investors to predict how they will change given that they are driven by underlying system physics.

I note the LCP analysis of the redundancy on the GB transmission system implied by the Transport model¹ line flows versus line capability, and the explanation that this seems to be largely related to power station closures and the allowance for the full capacity of generating plant in sizing circuits relative to the 70% scaling of wind in the year-round background. My view is that the level of transmission redundancy experienced as a result of a transition from a fossil-fuelled system to a low carbon system, with fundamentally different spatial characteristics and economics, is not an appropriate indicator of the expected redundancy for low carbon assets within a low carbon system. I also note that, as discussed below, the cost benefit analysis applied in the Network Options Assessment will not add transmission capacity to cater for the maximum output of generating plant.

¹ LCP 'Proposed Changes to Transmission Network Charging – April 2019'

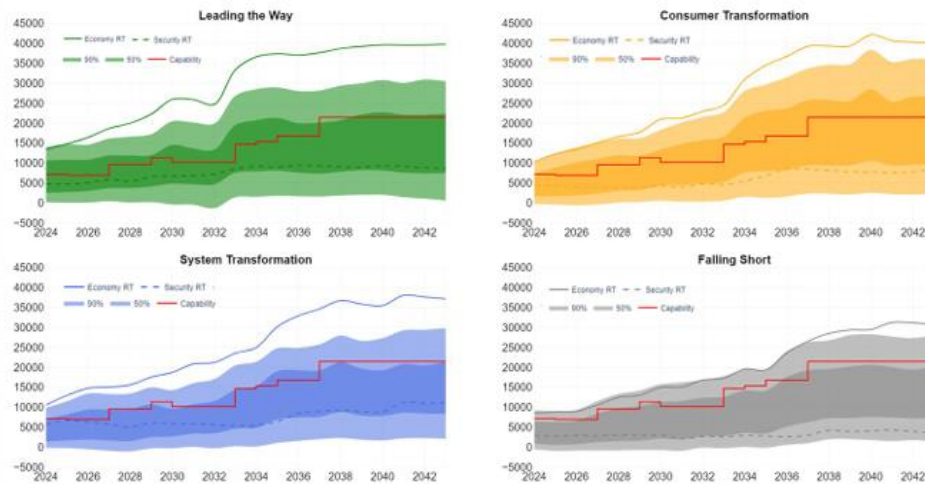
Given that the transmission pricing signals given by the ICRP methodology are intended to incentivise efficient locational decisions, and that the future transmission developed in response to generator siting will overwhelmingly be multiple circuits across key transmission boundaries, it seems important that the ICRP methodology recognises this. If this is not the case then inefficient investment signals will be given that could lead to a sub-optimal pattern of generation investment.

The economic undersizing of additional transmission relative to increases in generating capacity is currently imperfectly reflected in the Annual Load Factor (ALF) based sharing of some incremental MWkms in the ICRP tariff calculations. However, this will become less and less reflective of actual economic investment decisions as more low carbon capacity is built and sharing under the current formula diminishes as actual transmission sharing between low carbon generation assets increases.

A Locational Security factor for Wind

The above discussion of transmission development assumes that in response to an incremental MW of generation, transmission must be developed that can flow the 1 MW to demand. In fact, the development of GB transmission has historically been determined by the Network Options Assessment (NOA) cost benefit analysis for transmission expansion, with a transition now to the Strategic Spatial Energy Plan (SSEP) and the linked Centralised Strategic Network Plan (CSNP). The NOA cost benefit analysis results in an optimal transmission expansion path that does not fully cater for the maximum potential output of wind generation. This will be true for the SSEP and CSNP transmission optimisation as well.

The diagram below is from the Electricity Ten Year Statement and compares the optimal boundary transmission capability against the expected frequency distribution of power flows across the boundary for the key B6 boundary between Scotland and England. It is clear that transmission is not being expanded to a level consistent with maximum potential wind generation, let alone to a level significantly above this to provide redundancy. In fact, the coverage of maximum power flows looks rather like the 70% scaling parameter used in the year-round generation background (which is used to determine the base MWkms but is not applied to the assumed incremental generation which is of an unspecified technology).



The capability line (in red) is based on the recommendations from the Beyond 2030 report which uses the 2023 FES and ETYS data as inputs. The 50%, 90%, Economy RT and Security RT lines are based on FES 2023. The ETYS and NOA methodologies for this boundary are different and can result in different transfer capabilities.

The boundary capability is limited to 6.3GW due to a thermal constraint on the Harker – Moffat 400kV circuit

It is clear from the description in the NOA 2023 that the key line on these charts in terms of economic transmission development is the red line. As stated in that publication:

On each graph, the two shaded areas provide confidence as to what the power flows would be across each boundary:

- *The darker region shows 50% of the annual power flows*
- *The lighter region shows 90% of the annual power flows*

From the regions, we can show how often the power flows expected in the region split by the boundary are within its capability (red line). If the capability of the boundary is lower than the two regions over the next 20 years, there might be a need for reinforcements to increase the capability. However, if the line is above the shaded regions, it shows that there should be sufficient capability

here and that potentially no reinforcements are needed from a free market power flow perspective until the shaded regions exceed the capability (red line).

The TNUoS charges for all generators, including wind generators, are based on the incremental MWkms resulting from the addition of an unscaled MW of generation at each node multiplied by the locational security factor. This seems inconsistent with the actual impact of additional wind capacity on transmission expansion. Given the scale of the investment into wind generation anticipated in the short and medium term it is important that the locational investment signals provided by transmission charging give efficient cost signals. There would therefore be an argument that, in the absence of wind scaling being picked up elsewhere in the charge calculation, the locational security factor for wind should actually be 0.7 rather than 1.8. This would reflect the apparent level of investment into transmission in response to incremental wind capacity, which would seem to be an appropriate factor to consider in an investment cost related pricing approach.

As noted previously, this effect is partially picked up by the use of a power plant ALF in the 'sharing' of MWkms in the TNUoS transmission charge calculations, however the extent to which this recognises the sharing of transmission by low carbon generation will diminish as the proportion of low carbon generation on the power system increases. As shared MWkms in the T&T tariff calculation fall the tariff methodology will increasingly deviate from the actual relationship between wind capacity and investment in additional boundary capability.