Stage 02 – Workgroup Consultation	At what stage is this document in the process?
# CMP303 – Improving local circuit charge cost-reflectivity	01 Initial Written Assessment 02 Workgroup Consultation 03 Workgroup Report 04 Code Administrator Consultation 05 Draft CUSC Modification 06 Final CUSC Modification Report

Purpose of Modification: This modification seeks to make part of the TNUoS charge more cost-reflective through removal of additional costs from local circuit expansion factors that are incurred beyond the connected, or to-be-connected, generation developers' need.

This document contains the discussion of the Workgroup which formed in September 2018 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 5 of this document.

Published on:21 December 2018

Length of Consultation: 20 Working days

Responses by: 22 January 2019

Medium Impact: Some local circuit-connected generation connectees (medium or low – more probably low)

Low Impact: Other users of the transmission system (generators) who directly or indirectly pay TNUoS charge (very low)

Contents

1 About this document 3

2 Original Proposal 4

3 Proposer's solution 5

4 Workgroup Discussions 6

5 Workgroup Consultation responses 17

6 CMP303: Relevant Objectives 19

7 Implementation 20

8 Legal Text 20

Annex 1: CMP303 Terms of Reference 21

9 Annex 2: Alternate 1a 22

10 Annex 3: NGESO Analysis 23

11 Annex 4: Workgroup Member Analysis 26

Timetable

The Code Administrator recommends the following timetable:	
Workgroup Report presented to Panel	February 2019
Code Administration Consultation Report issued to the Industry	March 2019
Draft Final Modification Report presented to Panel	April 2019
Modification Panel decision	April 2019
Final Modification Report issued to Authority (25 WD)	May 2019
Indicative Decision Date	May 2019
Decision implemented in CUSC	1 April 2020

Any questions?

Contact:
Joseph Henry, Code Administrator

joseph.henry2@nationalgrid.com

07970673220

Proposer:
Paul Mott, EDF Energy

paul.mott@edfenergy.com

07752 987992

National Grid Representative: Harriet Harmon

harriet.harmon@nationalgrid.com

07970458456

1 About this document

This report contains the discussion of the Workgroup which formed in September 2018 to develop and assess the proposal.

Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The CUSC Panel detailed in the Terms of Reference the scope of work for the CMP303 Workgroup and the specific areas that the Workgroup should consider.

The table below details these specific areas and where the Workgroup have covered them or will cover post Workgroup Consultation.

The full Terms of Reference can be found in Annex 1.

Table 1: CMP303 ToR

Specific Area	Location in the report
a) Understanding the impacts on wider and local tariffs	Cover Post Consultation
b) Understanding the impact on generation and demand concerned	Section 4
c) Consideration of the overall benefits of the change v impact on consumers	Section 4
d) Clarify source and process of information required to determine the cost to be proportioned	Cover Post Workgroup

2 Original Proposal

Section 2 (Original Proposal) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 3 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

Defect

When a new local circuit is built to enable the export of new generation, extra costs may be incurred on additional functionality that is unrelated to the needs of said generation. For example, on an island requiring a DC connection, the transmission owner would naturally build the HVDC infrastructure as one-way, only allowing flow from the island, where the generation is located, to the mainland. There may be a cost difference if the link is built as bidirectional. The relevant TO may choose to incur any such incremental expenditure making the link bidirectional, if it felt that there were security benefits in terms of, under certain scenarios, securing demand. That is one example; there may be other additional functionality to be included in AC local circuits, that are at the behest of the transmission owner or system operator, and not related to the needs of the generator.

The defect is that, absent clarification of the exclusion of these extra costs, they are very likely to be included in the actual costs used to calculate the expansion factor and hence the relevant local circuit charge, meaning that relevant generators are facing a local circuit charge that is not fully cost-reflective.

What

The calculation of local circuit expansion factor should only include costs relevant to and needed by the connected generators. The incremental cost of extra functionality that the TO chooses to add, of wider benefit, should not be included. If the cost is already excluded under CMP301, if passed, then it could not also be excluded under this mod.

Why

If the calculation of the expansion factor and hence LCT, includes the cost of extra functionality included for wider societal/system benefits unrelated to the relevant generators' needs, the charge will not be cost-reflective as to what is being provided to connect up relevant generators, as opposed to what is additionally being provided for other transmission users.

How

Baseline CUSC says at 14.15.75 that AC cable and HVDC circuit expansion factors are to be calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors). It is suggested that a following paragraph be added, to make clear that where there are extra costs unrelated to the relevant generators' needs, they should be excluded from the relevant expansion factor. The Transmission Owner will provide the cost information on a case by case basis (to Grid), removing any additional costs not solely for the developer. STC procedures 13 and 14 already allow for the TO to provide relevant information to the TNUOS charging team, using broad and inclusive wording, so they will not need amendment.

3 Proposer's solution

Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 7 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

Baseline CUSC says at 14.15.75 that the AC sub-sea cable and HVDC circuit expansion factors are to be calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).   It is proposed, with this Modification that a following paragraph be added should make clear that the incremental costs, as identified by the TO, of extra functionality unrelated to the developers' needs, should be excluded.

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

The Proposer's view is that this change falls outside the scope of the "targeted charging review" SCR. This defect has certainly not been documented or discussed within the TCR seminars or documentation.

Consumer Impacts

There will be a diluted adverse impact on the charges faced by others – at present our understanding of the operation of EC838/2010 is that in today's climate it is other generators that would be affected, not Suppliers/consumers, though this may not always be the case.

4 Workgroup Discussions

The Workgroup convened 4 times between October and December 2018 and month year to discuss the perceived issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Applicable CUSC Objectives. The Workgroup will in due course conclude these tasks after this consultation (taking account of responses to this consultation).

The Workgroup discussed a number of the key attributes under CMP303 and these discussions are described below.

CMP303 seeks to change Section 14 of the baseline CUSC to amend part of the current TNUoS charge to be more cost-reflective through the removal of additional costs from local circuit expansion factors, that are incurred beyond the connected, or to-be-connected, generation developers' needs.

The Workgroup members were advised that the current defect, identified in CMP303, comes to the fore in situations which involve the construction of a new HVDC local circuit, which is used to enable the export of new generation. In such scenarios, extra costs may be incurred, often because of additional functionality which is not always related to the needs of the aforementioned generation, but actually arise from additional functionality sought by the Transmission (or Distribution) Owner.

In order to illustrate this issue, a scenario was presented by the Proposer whereby an island requiring a DC connection to the NETS for a connecting generator, then in principle the Transmission Owner would more than likely need to build a HVDC link as a one-way set up (in the opinion of the Proposer), which would only allow energy to flow from (and not 'to') the geographic location (in the main instance Scottish Islands) where the generation is located, to the mainland Great Britain energy networks.

However, if it was apparent that there were potential security benefits, for instance securing demand in uncertain situations, the relevant Transmission Owner (TO) may consider making the link bi-directional (so that energy could flow both 'from' and 'to' the connected location). However, there was expected to be a cost difference to the TO in such instances of building a bi-directional transmission link compared with building a mono-directional transmission link. There are potentially other scenarios where bi-directional functionality could be considered by a relevant TO. This additional functionality may see the TO incur extra costs, especially when one takes into consideration additional functionality (over and above what is needed for the connecting generator) which may be required in terms of local AC systems.

In the formative stages of this Workgroup, the Proposer highlighted to the Workgroup that factors as part of this modification are to be calculated on a case by case basis, using actual project costs. The relevant Transmission Owner would provide the cost information to National Grid, resulting in the removal of any additional costs not solely needed for connecting the developer's generation project. It was also highlighted that the System Operator Transmission Owner Code (hereafter referred to as the STC) Procedures 13 and 14 are currently set up to allow NGESO access the relevant information from the Transmission Owner, and as such will not need to be amended to allow for this modification.

The Proposer stated to the Workgroup that the solution should change the TNUoS charging regime to only include relevant costs associated with the needs of the connected generators. In that case, If the Transmission Owner makes a decision to invest in extra functionality, this should not be recovered from those generators.

Timescales and CfD Auctions

The Workgroup discussed the timescales for this modification and noted that they are dictated in some way by the upcoming 2019 Contracts for Difference (CfD) auctions. These auctions are expected to occur in either the summer or autumn of 2019, with prequalification occurring in the spring, however at this point the exact timings were yet to be defined. The importance of this modification in this case is that if this modification were to be implemented, then it would give any potential participants in this forthcoming auction the ability to compete in this auction efficiently, by them having the ability to forecast the local circuit tariff elements of TNUoS charging (which are a material factor for the parties concerned when seeking to participate in the auction) .

In order to do this effectively, said participants would need knowledge as to whether the TO in question is proposing to add further cost to TNUoS charges by constructing a link with extra functionality, which may not necessarily be needed by the developers of generation that are dependent on the link in question. It was highlighted to the Workgroup by the Proposer that this modification had the ability to provide such clarity to generation developers in terms of the potential of extra recovery of TNUoS costs when additional functionality is included in the link due to needs over and above those required by the relevant generation developers.

Interactions with Other Modifications

CMP301: Clarification on the treatment of Project Costs associated with HVDC and subsea circuits was raised by National Grid Electricity System Operator to CUSC Panel on 29 June 2018. In terms of the aims of CMP301, a previous modification (***CMP213 - Project TransmiT, the Authority's review of electricity transmission charging and associated connection arrangement***) introduced specific expansion factors for HVDC and subsea circuits. However, it is NGESO's opinion that the existing relevant legal text within the CUSC is open to interpretation – and as such the CMP301 proposal would cement the interpretation made by The Company to ensure consistency with onshore circuits.

At the time of Writing[1], CMP301 has been to The Authority and sent back for further information to be included in the Draft Final Modification Report, a direction received by the Code Administrator on 05 November 2018[2].

The Code Administrator will send CMP301 back to The Authority for decision in January 2019 and will await the final decision from Ofgem in regards to the approval and, if approved, the implementation of this modification. If the decision is received before 31 January 2019, included in the TNUoS forecasting for 2019/2020. Due to the closely linked subject matter, the CMP303 Workgroup would like to clarify in this report

[1] 21 December 2019

[2] https://www.nationalgrideso.com/sites/eso/files/documents/CMP301_send-back_letter.pdf

that throughout the discussions, CMP301 and its potential implications in conjunction with CMP303 have been considered.

The CMP303 Workgroup also noted that in the initial proposal, that the incremental costs of extra functionality (such as bio-directionality) that a TO may choose to add should not be included. If the cost is already excluded by the potential implementation of CMP301, then a similar exclusion could not take place under CMP303.

Benefits of the Modification

The Workgroup spent some time considering the benefits of the original proposal. One of the main considerations around the benefits of CMP303 was the level of cost reflectivity in generator TNUoS provided by the proposed change.

Understanding the Impacts of Wider and Local Tariffs, and Generation and Demand Concerned

In order to fulfil the requirements of this modification, the Workgroup agreed that the costings of mono-directional vs bi-directional transmission links would need to be understood in full. The Workgroup considered this and decided that the most efficient way to do this would be to engage with a HVDC supplier.

It was also agreed within the Workgroup that there may be Capex vs Opex cost considerations (as between a mono-directional vs bi-directional transmission link) which the Workgroup may need to consider to get a full picture of the benefits of CMP303. The Workgroup also recognised, that in theory there could be a distinction in regards to whether the modification would apply solely to the Scottish Islands, or to the GB Energy Network as a whole. The Workgroup noted that CMP303 deals only with the treatment relating to charging arising from the sub-sea cables and any associated convertor stations. Therefore any equivalent sub-sea Transmission assets anywhere in GB should be treated in the same way. The Proposer and the Workgroup agreed that the CMP303 solution would be applicable across GB as a whole where similar sub-sea transmission links were built.

The Workgroup also heard a suggestion that any alternatives should be passed on to the National Grid ESO TNUoS charging team as soon as available, so background work could be carried out to map in each potential scenario. This was seen as beneficial as it gives the teams within the ESO sight of potential permutations which could impact the final forecasting of TNUoS.

Consideration of the overall benefits of the change vs Impacts on End Consumers

Consideration was given in some detail to the impact CMP303 would have on generation and demand. The Workgroup set out to quantify the benefits of the proposed solution under CMP303, with cost reflectivity being the central theme of this work. The Workgroup endeavoured to understand how tangible and detrimental the current charging baseline error, as perceived by the Proposer, was within the CUSC.

Security of supply in specific geographic areas of the Scottish Islands was discussed within the Workgroup. It was said by some members of the Workgroup that as things stand, security of supply benefits may vary between islands. There was agreement that having bi-directionality of a future transmission link would further reinforce islands and could only add to their security of supply level.

The Workgroup broadly agreed that in the context of this proposal, a generator would only need a mono-directional link, but there were instances whereby functionality that is not required by the generator (such as moving from mono-directional to bio-directional) would bring additional benefits to network operators and / or demand when compared to a mono-directional link

Clarification of Source and Process of Information to determine the cost to be reapportioned

As things currently stand costing information available from the TO to the ESO would only be split out through asset/asset group. The ESO does not currently get the enhanced level of detailed information from the Transmission Owners needed to determine any additional costs associated with enhancing a transmission link from mon-directional to bi-directional.

A consideration of bi-directional functionality vs costs was undertaken by the Workgroup. National Grid ESO put forwards the opinion that any work the ESO undertakes in regards to the costs discussed in the CMP303 proposal would currently come from analysis of cost data currently collected from generation by the TO.

A Workgroup member stated that it was there expectation that there wouldn't necessarily be an interface between generation and demand. This prompted discussion in the Workgroup as to how often a Transmission Owner would provide information to National Grid charging teams in regards to Island transmission links. The Workgroup agreed that if CMP303 were to be implemented, differing from the initial assessment, that the nature, timing and information of the data flows between the respective Transmission Owners and NGESO would need to be clarified if the modification were to be implemented.

<u>Workgroup Analysis</u>

NGESO Initial Impact Assessment

After the first Workgroup meeting, NGESO were asked to provide an initial impact assessment for the Workgroup to take into consideration. NGESO has conducted some very high level analysis on the impacts of this, using a simplistic method of applying percentage decreases to local transmission circuit tariffs. This initial analysis can be found in Annex 4 of this consultation.

The analysis concluded that CMP303 would have an impact on the generation residual tariff, and that the demand residual tariff would not see any impact from the implementation of CMP303. The generation residual increase could be, according to the analysis, "between 10p and 57p from the scenarios we have used, becoming less negative". NGESO made it clear throughout their analysis that these figures are very high level; the Workgroup will need to explore this further following the development of the solution within the Workgroup.

Ofgem published a consultation document as part of the Targeted Charging Review (TCR) on 28th November 2018. Within the scope of the TCR is a holistic review of residual network charges. The future of the generation and demand residual charges, levied on all users of the transmission system, is discussed in depth. Ofgem has published a ‘minded to’ proposal which means no generator should pay residual charges; the practical effect of this would be to set the TGR to zero.

The effect of this consultation on NGESO’s implications assessment is that the proposed cost shifting from local circuit tariff to generation residual would instead be shifted onto the demand residual. No analysis has been undertaken to assess the size of the impact on the demand residual, however it would certainly increase.

Workgroup Member Analysis

Further analysis in regards to CMP303 was undertaken by another Workgroup member, and presented to the Workgroup for their consideration. The analysis examined examples pertinent to this modification. This analysis is available in Appendix 5 of this report.

Hinckley Point

The first example given in that Workgroup members’ analysis examined the increase in TEC from the Hinckley Point Power Station, in terms of what the lengths of overhead lines/cable that are being delivered were, and which were then subsequently multiplied by the expansion factors.

The analysis undertaken suggested that the reinforcement cost of this work at Hinckley Point was around £800m, of which around 10% could be explained by expansion factors. For Hinckley Point, 90% of the reinforcement costs are socialised. Onshore AC connections require substations, however the analysis stated that these substation costs are socialised. The example of the first 275kV circuit built in GB from Tyneside to Strathclyde was positioned to the Workgroup. This line would require 275kV substations which did not exist prior to the point at which works began. The analysis stated that this is analogous to HVDC requiring converter stations. It was also highlighted that the onshore AC assets constructed for Hinckley Point require undergrounding of DNO assets to achieve planning permission.

The analysis further described that these costs are socialised and not assigned to the generator concerned, however the cost of undergrounding/subsea installation to the islands required by the physical geography is currently fully allocated to the island generator users. This would back the Proposer’s point that Island located generators may be discriminated against under current arrangements, if we compare these to other points of interest on the transmission network.

Pembroke to Walham

AC substations and AC transmission were considered within the Workgroup member’s analysis, giving the example of the Pembroke to Walham 400kV substations. The analysis highlighted that treating those differently to HVDC is not necessarily discriminatory. Further Analysis was presented which stated that AC transmission circuits require more assets than just cables or lines in order to function. One such example of this is the Harker to Strathavan reinforcement in the 1990s.

Further exploration of the optimisation of capacity for lower costs and charges was detailed. It was underlined that OFTO assets are sometimes designed and built by offshore developers, but it was opined by the ESO that the OFTO cannot have fully bespoke assets in the majority of cases. It was opined within the Workgroup that generation developers control the ratings and costs of these OFTO assets and can consequentially manage their TNUOS charges. Island generation developers do not control the size or cost of assets, which are determined by the Transmission Owner, and subsequently, island generation developers are not able to manage TNUoS charges, creating a disparity in the market, in the opinion of some Workgroup members.

An example, based on the HVDC cost model developed for Green link and Mali interconnector projects, which were undertaken by Statkraft was examined. Statkraft calculated that the additional costs of taking the Shetland HVDC connection from 600MW to 800MW is less than 4% for the 33% capacity increase. The larger capacity would reduce TNUOS by a tangibly larger amount than the increase in capital cost. The provider of the analysis stated that in their opinion the offshore generation developer could manage and exploit benefits of scale as highlighted, whereas the island generation developer cannot, which highlighted similar themes as put forward by the Proposer of CMP303.

Cost effectiveness of HVDC – is it always more expensive?

The Workgroup member who provided the analysis also opined that a HVDC transmission link can have a lower cost than an AC transmission link. It was mentioned that there may be assumptions within industry that HVDC based solutions are always more expensive than AC solutions, however this is not always the case. The competition to replace the Shetland Power Station demonstrated that an HVDC transmission link (with converters and cables) was the most cost effective.

Some Workgroup members often stated their belief that HVDC island transmission links provide security of supply, something which this analysis concurred with. A pertinent example put forwards by the analysis was that the Shetland Islands are not connected to the GB transmission grid and the power station requires replacement. A competition to replace that power station identified the lowest cost solution as an HVDC transmission link from Shetland to the GB mainland. The cost of the HVDC part of the solution was £279m if a transmission link is built to Shetland to enable generation exports, the bi-directional transmission link will also provide a supply to the island to replace the power station with a capital saving of £279m.

The avoided cost could be deducted from the actual cost of the HVDC transmission link before TNUOS charges are calculated, which may arguably improve the cost reflectivity.

The same principle of security of supply would apply to other remote islands, and as cost saving information is not to hand for these islands therefore the same percentage cost reduction for transmission charging purposes should be applied to other remote islands, as with HVDC links for Shetland. The Workgroup gave this issue some consideration in regards to how this was recovered via TNUoS. A Workgroup member highlighted that that this could be applied through the residual across all UK users.

The analysis provided, further explored the geographic and historical nature of TNUoS. The work undertaken shows that for the Hinckley Point transmission reinforcements, 90% of the costs were associated with works other than the 400kV overhead lines and cables themselves. When the Beauly Denny 400kV upgrade was completed there was a reduction in the northerly TNUOS charges within the GB market as a consequence of the decreased unit capacity costs. The analysis undertaken contended that both aforementioned projects incurred investment costs but did/will not raise transmission charges commensurately, with any negative impact to end users. There was broad agreement in the Workgroup on the matter.

Based on their geographical position within the GB Energy Market, old and new assets have been constructed at lower voltages than 400kV for “permitting or historic reasons”. According to the analysis, lower transmission voltages may incur higher local TNUOS charges on generation users. However, there is no commensurate reduction in transmission charges for demand users.

It was put forward that transmission reinforcements are increasingly expected to involve sections of more expensive underground cable in order to satisfy aesthetic expectations from the general public, which have come to the fore more prevalently in recent years. The analysis henceforth suggested that to circumnavigate the “arbitrary nature” of transmission charges due to “historic or geographical reasons”, a standard expansion factor could be applied to all transmission assets with no consideration given to the voltage or type of the asset.

In summary, the Workgroup member’s analysis concluded that AC transmission networks have a tangible requirement for substations to function efficiently and transmit power. The substations house switchgear and protection, transformers, reactors, capacitors, stat-coms, series capacitors and quad boosters which are required to deliver power transfer of AC.

The analysis further concluded that these above mentioned assets are not multiplied by the expansion factors whereas HVDC converters are. Thus 50%-90% of the costs of building/reinforcing AC transmission networks are not included in AC the expansion factors. AC transmission networks require ancillary services to operate them including reactive power, dynamic voltage control, inter-tripping etc. Furthermore, it was put forward that these costs are not incurred on HVDC transmission links. OFTO linked generation developers control the sizing of their assets and can cost optimise, whilast inland generation developers cannot. HVDC transmission links also provide security of supply on remote islands. A Workgroup member argued that the nature of network transmission charging is somewhat arbitrary, whilst generally cost reflective there are instances when this is not the case. A standard ‘km’ based expansion factor regardless of circuit voltage or asset type would remove such idiosyncrasies.

One Workgroup Member wanted the working group to have some grasp on the potential cost savings on a unidirectional HVDC system noting there was a risk that workgroup members may think that unidirectional flow would save 50% of the costs. The Workgroup member noted that they had not seen any technical papers or proposals as to how such a system would be designed. Therefore the Workgroup member presented a very high level off the cuff ballpark assessment of the potential cost savings a unidirectional HVDC link might bring. It was mooted by this workgroup member mooted that the cost of converters might be 40% of the overall system costs (60% being cables). For unidirectional flow the cost saving was mooted to be at the island end with unidirectional power flow i.e. rectifier to convert AC to DC. So the saving would be on one of the two converters i.e. on 20% of the cost base. It was assumed that half the cost of the converter was associated with power electronics and controls (other costs such as land, civil works, transformers, busbars, switchgear, etc would be the same) and therefore the cost savings would apply to 10% of the total HVDC cost.

Assuming the cost differential to be half for the reduced power electronics (e.g. diodes vs IGBTs) the overall saving would be 5% of the total HVDC cost. Ze noted however that bidirectional flow would be required to energise the AC network and provide power to the wind turbines during no wind periods and to produce a 50Hz AC waveform on the island which could incur additional costs such as synchronous compensators or standby generators which would eat into any cost savings.

Security of Supply

It was argued within the Workgroup that HVDC island transmission links, where bi-directional, may provide security of supply to island networks. An example was given, illustrating that the Shetlands are not connected to the GB electricity grid and the power station there requires replacement. A competition to replace that power station identified the lowest cost solution as an HVDC transmission link from Shetland to GB mainland. The cost of the HVDC part of the solution was [£279m] if a transmission link is built to Shetland to enable generation exports, the transmission link would also provide an island supply to replace the power station with a capital saving of £279m.

It was positioned that this avoided cost could be deducted from the actual cost of the HVDC transmission link before TNUOS charges are calculated. The same principle of security of supply applies to other remote islands, and as cost saving information is not to hand for these islands the same percentage cost reduction for transmission charging should be applied to other remote islands with HVDC links as for Shetland.

Shetland as a charging model

The suitability of using the example of the Shetland HVDC link was discussed by the Workgroup, and it was agreed that more tariff analysis would need to be conducted into this matter. The £279m cost of the Shetland HVDC transmission link was proposed and the costs of the link including the back-up diesels. The reasoning as to this was that the diesel generation would match the distributional demand whilst the cables were down. A belief was expressed by a Workgroup member that this cost would be picked up through all GB DUoS charging, and if this was the case, that it should be applied to all island connections. The Workgroup discussed whether the interaction between TNUoS and DUoS should come about, concluding that it should not, as this modification is dealing solely with TNUoS charging. This lead to a discussion as to whether a solution involving Distribution Network Operators should be sought; however, due to the previous point raised, it was decided against.

Potential Alternatives put forward by the Workgroup

Please note that at this stage, all proposed alternatives have not been voted on, and have been given for full consideration.

The initial CMP303 solution points to CUSC section 14.15.75, which highlights that AC sub-sea cable and HVDC circuit expansion factors are to be calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

As well as the initial solution proposed, there were four initial potential alternatives proposed by one Workgroup member. They were as follows:

1. **Remove all converter station costs from HVDC charging**

This potential alternative sets out that industry would think that the provision of equipment/cabling would provide additional functionality, which may not have initially be required but is inherent with the installation of said equipment/cable. The Workgroup discussed the possibility that due to this, potential alternative 1 needed to be revisited in terms of the scope.

The Workgroup concurred that the system could get the value with only the TO paying. The possibility of raising a new modification to include this concern within a new defect was discussed. It was also explored whether as to the possibility of whether a link with a thyristor element would provide additional functionality but the cost saving would be reduced. It was also discussed that some of the savings are being taken away from the costs unnecessarily.

An argument was put forward that power electronics costs would also exist within the AC world as well as DC, and that the DC design choice has value as it avoids other costs. In this respect, potential alternative 1 would remain in scope due to this. It was highlighted that Ofgem would have the final scrutiny within any "needs case", and associated efficiencies.

The Workgroup were made aware that the Authority would have the ultimate recourse on making the decision on whether this potential alternative was within the scope of the defect.

The Workgroup came to a conclusion on whether the first potential alternative was in scope of the modification defect. The Workgroup agreed that the potential alternative was in scope of the modification and should be brought forwards accordingly.

Potential Alternative 1a – Wider System Benefits of HVDC

This alternative identifies additional functionality of HVDC local circuits that is unrelated to the needs of the generation whose export is facilitated by the HVDC local circuits. It proposes to quantify the costs of this additional functionality by examining the costs of equivalent plant or services. The costs of the equivalent plant or services are then deducted from the HVDC costs entered into the generator local circuit TNUoS charge calculation to reduce the charge the relevant generators pay.

At the time of writing, the workgroup had not had enough time to fully consider this potential alternative. The detail behind this potential alternative, should you wish to read it, is located in Annex 2 of this document.

2. **For Island HVDC charges, recognise the alternatives of making a supply to the islands via distribution rated HVDC and subtract this benefit form the cost before applying TNUOS. As these costs are clear for Shetland, use Shetland as the model and apply same percentages to HVDC link to the Western Isles.**

The second initial potential alternative, suggested within the Workgroup, looked at how Island charges could reflect and recognise security of supply benefit by subtracting from cost, before applying TNUoS charging. It was argued that a similar percentage applied to Shetland could apply to other islands. A belief was discussed within that Workgroup that any such application should be determined by Ofgem, as project specific figures would be more cost reflective than the application of a generic percentage, based solely on one (Shetland) island network. Several Workgroup members agreed on the matter.

After further discussion, the Workgroup decided to break down potential alternative 2 into three separate potential alternatives, which will be referred to as 2(a) (mirroring the original), 2(b) and 2(c) respectively. It was agreed that the term "distribution rated HVDC" should be removed from the alternatives also.

Potential alternative 2(a) - For Island HVDC transmission charges, recognise the alternatives of making a supply to the islands and subtract this benefit form the cost before applying TNUOS. As these costs are clear for Shetland use the Shetland percentage as the model and apply same percentages to HVDC link to the Western Isles and Orkney.

Potential alternative 2(b) – For Island HVDC transmission charges, recognise the alternatives of making a supply to the islands and subtract this benefit form the cost before applying TNUOS.

It was highlighted during Workgroup discussions that the relevance of using the Shetland specific percentage as an example may have some flaws; primarily on the grounds of being less cost reflective. One such issue was that Shetland is approximately 150km[3] from the Scottish Mainland, whereas the Western Isles and Orkney are considerably closer. This would likely see a difference in the actual costs for the respective transmission links. As such, whether it is sensible to utilise the Shetland calculated percentage as a like for like example to other locations (such as the Western Isles or Orkney) was disputed.

Potential alternative 2(b) reflects this thinking, by removing the reference to applying the Shetland percentage to any other island groups from this potential Alternative. Instead the percentage would be calculated on a case by case basis meaning that the Shetland percentage would apply only to the Shetland based local circuit TNUoS whilst the Western Isles and Orkney, for example, would have their own Western Isles or Orkney local circuit TNUoS charges (based on their own respective percentages).

Potential alternative 2(c) – Pro Rated S/D

For HVAC subsea cable connections or new HVDC connections that constitute a generator local circuit for the purposes of TNUoS charging, the proportion of the costs of the connection for import flows from the mainland to the island, for example for demand, should not be charged to the relevant generators. This is achieved by deducting (pro-rata) a proportion of the cost of the connection from the relevant cost

[3] https://www.scotlandinfo.eu/shetland/

entered to the generator local circuit TNUoS calculation. This pro-rata proportion shall be calculated using the import / generation export ratio.

It was highlighted that potential alternative 2(c) may allow the inclusion of import flows (from the mainland to the island) for considerations other than demand, for example future interconnector requirements.

3. **Given the discrepancies in charging and the historical and geographical accidents and associated costs relating to either: the remote islands; or the densely populated areas of England; or the landscape designations; apply a single global GB expansion factor to all assets: AC and DC; cable and overhead line; and all voltages; to remove these idiosyncrasies.**

   The initial iteration of potential alternative 3 applies a single global expansion factor for all relevant assets. It was suggested that this potential alternative 3 was possibly out of scope of the original CMP303 defect. The Workgroup discussed this at length, and eventually deciding that potential alternative 3 was not in scope of the modification. The Workgroup also agreed that potential alternative 3 would materially affect all Scottish tariffs, and would result in distortions in cost reflectivity. Potential alternative 3 was not subsequently formally submitted to become a WACM and was discontinued for the purposes of this Workgroup.

4. **Combination of 1&2**

Options 4(a) and 4(b) are hybrids of potential alternative 1, with the three combinations which were born out of potential alternative 2:

4(a) Remove all converter costs for HVDC charging, and for Island HVDC charges, recognise the alternatives of making a supply to the islands via distribution rated HVDC and subtract this benefit from the cost before applying TNUOS. As these costs are clear for Shetland use Shetland as the model and apply same percentages to HVDC link to the Western Isles.

4(b) Remove all converter costs for HVDC charging, and for Island HVDC charges, recognise the alternatives of making a supply to the islands via distribution rated HVDC and subtract this benefit form the cost before applying TNUOS.

These combinations look to enhance the suggestions made in potential alternative 1, by adding 2(a) and 2(b) alternative solutions to form a potentially more encompassing solution in the opinion of some Workgroup members. As the Workgroup agreed the solutions outlined in potential alternatives 1 and 2 fell within scope of the original CMP303 proposal, then logically, the hybrids documented here should also.

Potential alternative 4(b) would be based on the island specific costs that would be associated with building an equivalent distribution link to the GB mainland instead of the transmission link on a case by case basis.

5. Combination of 2&3

As potential alternative 3 was discontinued, so potential alternative five, which combined a hybrid of potential alternates 2 and 3, followed suit.

5 Workgroup Consultation responses

The CMP303 Workgroup is seeking the views of CUSC Parties and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

Standard Workgroup Consultation questions:

Q1: Do you believe that CMP303 Original proposal better facilitates the Applicable CUSC Objectives?

Q2: Do you support the proposed implementation approach?

Q3: Do you have any other comments?

Q4: Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?

Specific CMP303 Workgroup Consultation Questions:

Q5: Do you consider that any or potential alternatives set out in Section 4 have merit? if so please provide your rational.

Q6: Do you consider that any or potential alternatives set out in Section 4 do not have merit? if so please provide your rationale.Q7: National Grid ESO have identified a number of potential implications associated with CMP303 which are set out in Appendix 3. Do you agree or disagree with this assessment? If so, please explain why.

Please send your response using the response proforma which can be found on the National Grid website via the following link:

https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/improving-local-circuit-charge-cost

In accordance with Section 8 of the CUSC, CUSC Parties, BSC Parties, the Citizens Advice and the Citizens Advice Scotland may also raise a Workgroup Consultation Alternative Request. If you wish to raise such a request, please use the relevant form available at the weblink below:

http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Views are invited upon the proposals outlined in this report, which should be received by **5pm** on 22 January 2018

Your formal responses may be emailed to: cusc.team@nationalgrid.com

If you wish to submit a confidential response, please note that information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response market "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the CUSC Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential"

6 CMP303: Relevant Objectives

Impact of the modification on the Applicable CUSC Objectives (Charging):	
Relevant Objective	Identified impact
(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;	Positive – allows relevant generators to compete fairly in the market without being handicapped by paying extra costs unrelated to the export of their power
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	Positive – ensures relevant generators face a cost-reflective local circuit charge, without paying for extra costs unrelated to the export of their power
(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;	Positive – HVDC island links don't exist yet, this mod among other scenarios covers the case where the TO adds bidirectionality as a function to such a link. This mod brings the CUSC up to date and ensures any such developments in relation to local circuit charges are properly taken account of in a fair and cost-reflective manner
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1*; and	Not Relevant
(e) Promoting efficiency in the implementation and administration of the CUSC arrangements.	Not Relevant

*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

7 Implementation

This CMP303 proposal is linked to an imminent date related issue; namely the date of the next CFD auctions that some local-circuit-connected generators, both AC and DC connected, will compete in to secure support, which is expected to be held in March 2019 or shortly after (in any event, by or before June 2019). In order to compete in this auction efficiently, this generation plant must be able to forecast the local circuit tariff element of their TNUoS charge (which could be materially impacted if this proposal was or was not approved). Therefore this CMP303 modification would require a decision by the Authority (with it to be **implemented** at the start of next charging year) at least a few weeks ahead of the earliest conceivable auction tender submission deadline.

8 Legal Text

- Replace 14.15.75 and 76 with,
- 14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors), except that these project costs should only include costs relevant to and needed by the connected generators. The incremental cost of any extra functionality that the TO chooses to add, of wider benefit, should not be included.
- 14.15.76 Subject to 14.15.75, for HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

Annex 1: CMP303 Terms of Reference

Workgroup Terms of Reference and Membership
TERMS OF REFERENCE FOR CMP303 WORKGROUP

CMP303 seeks to make part of the TNUoS charge more cost-reflective through removal of additional costs from local circuit expansion factors that are incurred beyond the connected, or to-be-connected, generation developers' need.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP303** Improving local circuit charge cost-reflectivity, tabled by EDF Energy at the Modifications Panel meeting on 27 July 2018.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

   Non-Standard (Charging) Objectives

   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 (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);

   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;

   d. Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1 *; and

   e. Promoting efficiency in the implementation and administration of the CUSC arrangements.

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

   a) Understanding the impacts on wider and local tariffs
   b) Understanding the impact on generation and demand concerned
   c) Consideration of the overall benefits of the change v impact on consumers
   d) Clarify source and process of information required to determine the cost to be proportioned

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

9. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **15 working days** as determined by the Modifications Panel.

11. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **TBC** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **TBC.**

Membership

13. It is recommended that the Workgroup has the following members:

Role	Name	Representing
Chair	Shazia Akhtar	National Grid ESO Code Admin
National Grid ESO Representative	Eleanor Horn	National Grid ESO
Industry Representatives	Paul Mott Simon Swiatek Guy Nicholson Garth Graham Sharon Gordon Nigel Scott	EDF (Proposer) Forsa Statkraft SSE SHE Transmission Xero
Authority Representatives	Tim Aldridge	OFGEM
Technical secretary	Joseph Henry	National Grid

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP303 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal;

- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

16. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

17. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

18. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

19. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

Appendix 1

Proposed CMP303 Timetable

The Code Administrator recommends the following timetable:	
Workgroup Report presented to Panel	February 2019
Code Administration Consultation Report issued to the Industry	March 2019
Draft Final Modification Report presented to Panel	April 2019
Modification Panel decision	April 2019
Final Modification Report issued to Authority (25 WD)	May 2019
Indicative Decision Date	May 2019
Decision implemented in CUSC	1 April 2020

9 Annex 2: Alternate 1a

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WACM 1A
WIDER SYSTEM BENEFITS OF HVDC

CMP303 WORKGROUP

20/12/2018

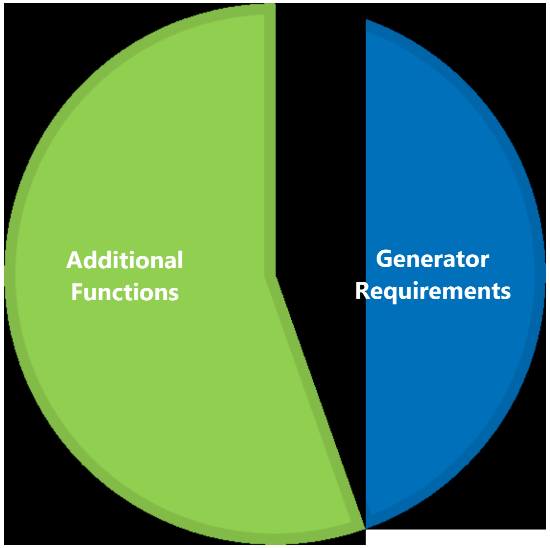
Nigel Scott

Introduction

- What does CMP 303 propose?
  - Only the relevant costs to facilitate export should be passed to the generator
  - Costs of additional functionality should be removed

- What does WACM 1A propose?
  - HVDC system has additional functions not required for generator export
  - These have a value to the wider system and their equivalent cost should be removed

- Contents
  - HVDC TNUoS charging history
  - Current generator HVDC local circuit method
  - Additional functionality
    - Reactive power provision, Voltage control, Power flow control, Black start
  - Cost reductions
  - Summary and conclusions



Local circuit tariff

HVDC TNUoS Charging History

Project TransmiT

- Ofgem review of TNUoS charging arrangements
- Focused on wider zonal element
- Considered HVDC wider system benefits.

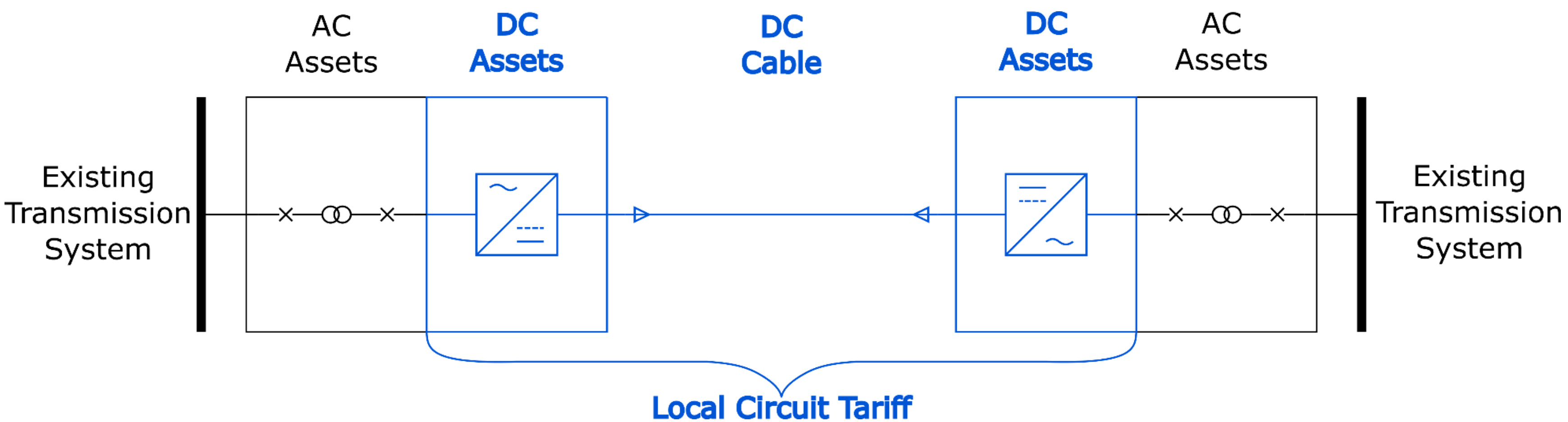
CMP213

- National Grid process
- Considered socialising HVDC convertor costs in whole or part
- Ofgem concluded
  - Lacking quantified evidence of HVDC wider system benefits
  - Should be addressed at a later and more appropriate time.

Current generator HVDC local circuit method

- Local circuit tariff for HVDC
  - Includes convertors and cables
  - Convertors considered an integral part of the circuit.
- Differences to onshore AC system
  - Includes overhead lines and underground cables
  - No substation assets included.

Example 600MW HVDC Link	
HVDC converters	300
HVDC cables	300
HVAC assets	100
Total for TNUoS	600
TNUoS, £/kW/annum	76

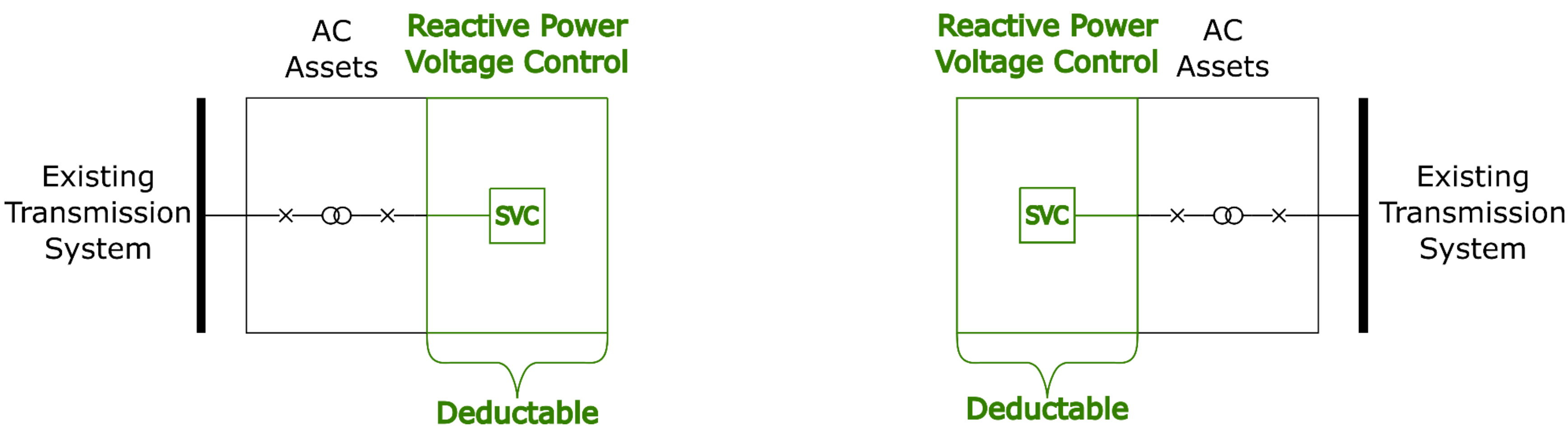


Reactive Power & Voltage Control

- Additional functionality
  - Converters provide a reactive power and voltage control capability
  - Equivalent devices: SVC, STATCOM etc
  - Each end can operate independent of the other.

- Onshore AC methodology socialises reactive power and voltage control devices.

Example 600MW HVDC Link	
Equivalent plant (debit)	**(200)**
HVDC converters	300
HVDC cables	300
HVAC assets	100
Total for TNUoS	400
TNUoS, £/kW/annum	51

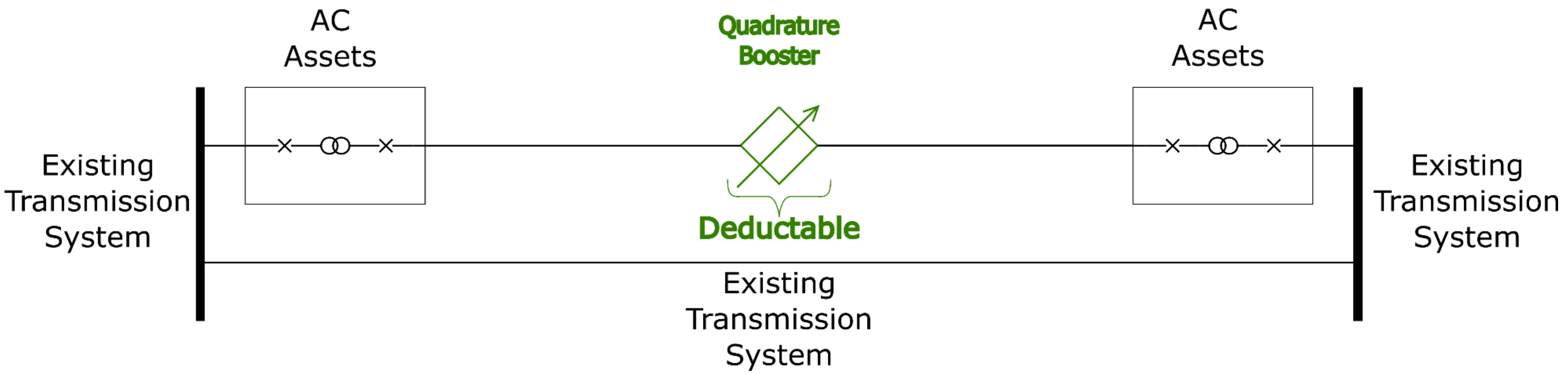


Power Flow Control

- Additional functionality
  - HVDC system can control power flow in (parallel) circuits
  - Equivalent device: Quadrature booster
  - Only relevant to one end.

- Onshore AC methodology socialises quadrature boosters.

Example 600MW HVDC Link	
Equivalent plant (debit)	**(7.5)**
HVDC converters	300
HVDC cables	300
HVAC assets	100
Total for TNUoS	592.5
TNUoS, £/kW/annum	75

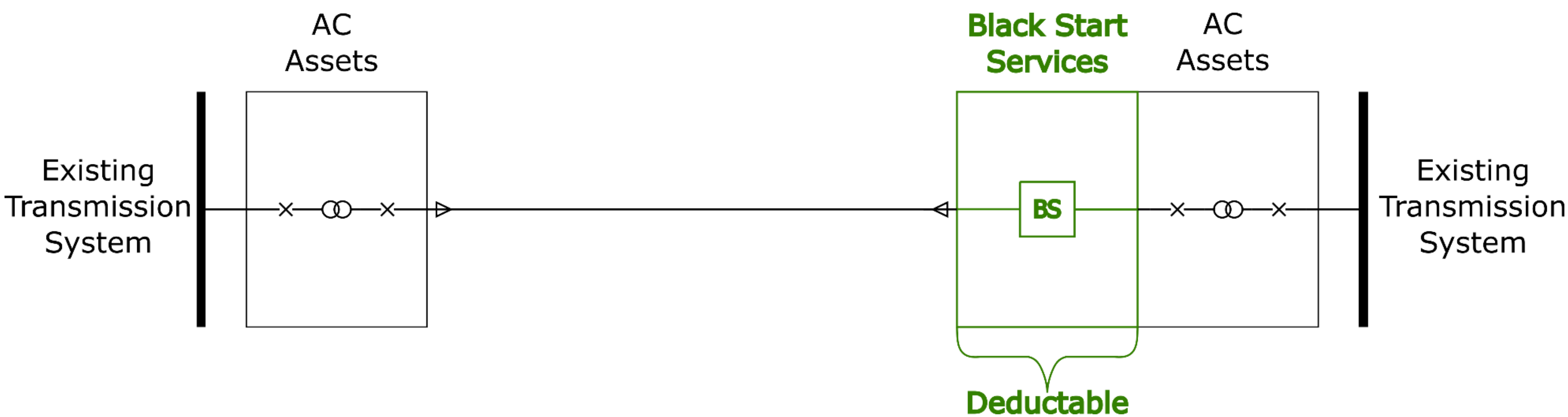


Black Start

- Additional functionality
  - HVDC system can black start dead system at one end
  - Equivalent device: service procurement from large synchronous generators
  - HVDC provides black start at one end (at a time).

- Onshore AC methodology does not include black start costs - cost recovery is via BSUoS

Example 600MW HVDC Link	
Equivalent plant (debit)	(125)
HVDC converters	300
HVDC cables	300
HVAC assets	100
Total for TNUoS	475
TNUoS, £/kW/annum	60



Cost Reductions

Item	Costs, £ million				
	Shetland and Western Isles HVDC links	Reactive power & voltage control	Quadrature booster	Black Start	All 4 functions
Equivalent plant (debit)	-	**(200)**	**(7.5)**	**(125)**	**(332.5)**
HVDC converters	300	300	300	300	300
HVDC cables	300	300	300	300	300
HVAC assets	100	100	100	100	100
Total for TNUoS	600	400	592.5	475	267.5
TNUoS, £/kW/annum	76	51	75	60	34

Summary & Conclusions

- This WACM 1A proposes to remove the costs of equivalent plant that would otherwise provide the additional functionality the HVDC link provides (that is not needed by the generators). This should be examined on a case by case basis.

- It is found that:
  - HVDC offers high value to the wider system
  - This value may be more than the HVDC converter costs but probably less than the overall HVDC system cost
  - This should therefore remove a large part of the cost entered into the generator local circuit TNUoS calculation for an HVDC system
  - The method should be extended to other relevant HVDC links to assess whether the findings are consistent
  - Note that there is other functionality not addressed here.

- The work also supports WACM 1 - total removal of HVDC converter costs from the generator local circuit charge
  - WACM 1 simplifies calculations by not undertaking the case by case analysis
  - WACM 1 (and 1A) align with existing onshore charging methodology where substations are not included.

Version History and References

Version History

V	AUTH	DATE	NOTES
A	NCS/FW	17/12/2018	First version for CMP303 WG4 – 20 Dec 2018

10 Annex 3: NGESO Analysis

CMP303 Initial Impact Analysis of the Modification

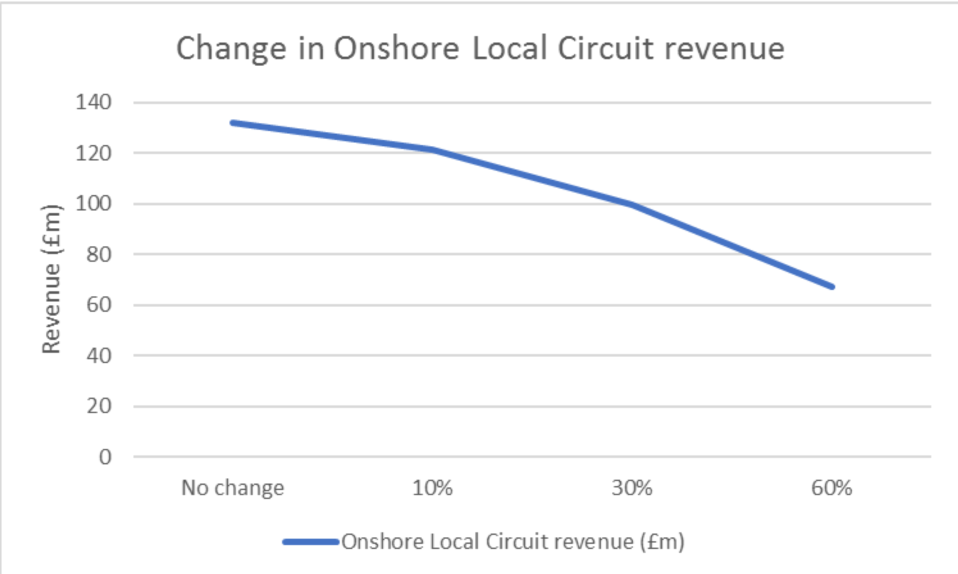
CMP303 'Improving local circuit charge cost-reflectivity', was raised by EDF in September 2018. This modification looks to make part of the TNUoS charge more cost reflective through the removal of additional costs from the local circuit expansion factors that are incurred beyond the connected, or to-be connected, generation developers need.

Following the first workgroup, NGESO has conducted some very high level analysis on the impacts of this, using a very simplistic method of applying percentage decreases to local circuit revenue. There are some caveats which need to be considered when looking at the results of this analysis:

- The local circuit revenue amounts have been amended rather than the local circuit expansion factors. This is because these factors are contained within the Transport & Tariff model. Therefore, taking into account the time it would need and the complexities around this method of analysis we decided to adjust the local circuit revenue amounts as this would be sufficient for an initial impact analysis.
- We have used a percentage change in the local circuit revenue amounts rather than a specific figure as no methodology has been worked out yet. Therefore, this is a good way to see potential impacts on tariffs initially before a clear solution is developed by the workgroup.

To carry out the analysis, we have conducted a number of scenarios. We have reduced the local circuit revenues (of certain parties) by 10%, 30% and 60% compared to baseline (no change).

The following graph shows the change in local circuit revenue for each scenario:



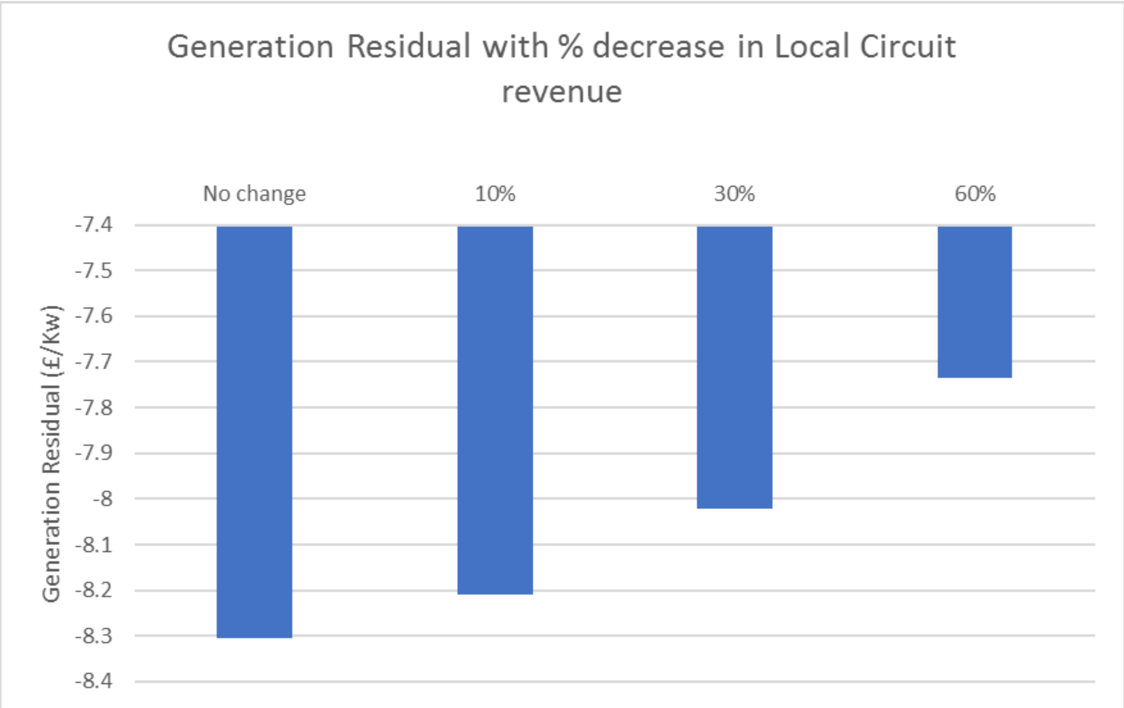
(Source: Analysis based on August 2018 5-year forecast, using 2023/24 scenario T&T model)

The following table notes the impacts on residual tariffs (both demand and generation):

	Generation Residual	Monetary change in Gen Residual compared to baseline	Demand Residual	Monetary change in Dem Residual compared to baseline
No change (baseline)	-8.31	0.00	66.79	0.00
10% decrease	-8.21	-0.10 (i.e. less negative)	66.79	0.00
30% decrease	-8.02	-0.29	66.79	0.00
60% decrease	-7.74	-0.57	66.79	0.00

(Source: Analysis based on August 2018 5-year forecast, using 2023/24 scenario T&T model)

As you can see from the table there is only an impact on the generation residual tariff. The demand residual tariff is not impacted at all. The generation residual increases by between 10p and 57p from the scenarios we have used, becoming less negative.



(Source: Analysis based on August 2018 5-year forecast, using 2023/24 scenario T&T model)

Therefore, this modification will reduce the local circuit tariffs for generators who will be covered by this modification. However, this reduction has (from the analysis above) reallocated the costs to the generation residual and so all other generators will pick up the costs of this modification in this scenario.

As this is only initial and very high level analysis, the workgroup will need to consider their solution in detail. Due to the intricacies of the Transport and Tariff Model, the modification will have to be very clear on what calculation will need to take place and also the information provision from the TO and how this fits into the model. This will ensure that the analysis is reflective of the modification's intent.

11 Annex 4: Workgroup Member Analysis

CMP303 GB HVDC ISLAND TRANSMISSION CHARGING

Submission to Working Group for Connection and Use of System Code (CUSC) modification CMP303 regarding transmission charging for HVDC and remote islands in GB.

The contents of this presentation are the work of the author and are for consideration, discussion, endorsement, modification, enhancement or correction by the working group and are not necessarily approved or endorsed by Statkraft.

<u>Distribution: CMP303 Workgroup</u>

Prepared by Guy Nicholson 29/10/2018

Statkraft

Contents

- Defect defined in CMP303
- Evidence of defect and additional costs of AC solutions
- Charging of AC onshore vs HVDC to islands
- More AC substations provide more AC transmission capacity
- AC circuits require more assets than just cables or lines in order to function
- HVDC can be cheaper than AC
- Optimisation of capacity for lower costs and charges
- WACMs

Defect stated in CMP303

1 Summary

Defect

When a new local circuit is built to enable the export of new generation, extra costs may be incurred on additional functionality that is unrelated to the needs of said generation.

The defect is that, absent clarification of the exclusion of these extra costs, they are very likely to be included in the actual costs used to calculate the expansion factor and hence the relevant local circuit charge, meaning that relevant generators are facing a local circuit charge that is not fully cost-reflective.

Evidence of defect and additional costs of AC solutions (1of2)

- As evidence of the defect, an analysis has been undertaken of the reinforcement works proposed for the new Hinkley Point power station.
- The capacity increase delivered and the lengths of overhead line and cable have been multiplied by the expansion factors to determine the proportion of project Capex associated with these elements that is used in the TNUOS charges.
- The costs for Hinkley – Seabank are £800m (Ofgem).
- The new connection is 48.5km of overhead line and 8.5km of underground cable (NG Hinkley Connection Project).
- The incremental TEC delivered is the new TEC (2*1670 – 1261)=2079MW (TEC Register).

Executive Summary

The Hinkley-Seabank Project

The Hinkley-Seabank project (HSB) is an electricity transmission project to connect EDF's Hinkley Point C nuclear power station to the GB transmission network. HSB has been progressed through the planning process by National Grid (NGET) as the transmission owner (TO) for England and Wales. The cost of the project is currently estimated at close to £800m.

https://hinkleyconnection.co.uk/project-summary/

The Hinkley Connection project is a new high-voltage electricity connection between Bridgwater and Seabank near Avonmouth. It is a significant investment in the region's electricity network and will enable us to connect new sources of power to homes and businesses, including Hinkley Point C, EDF Energy's new nuclear power station in Somerset.

It will play a vital role in delivering electricity efficiently, reliably, and safely and will support the UK's move to reduce carbon emissions.

The new connection will be 57 km long – consisting of 48.5 km of overhead line and 8.5 km of underground cable through the Mendip Hills Area of Outstanding Natural Beauty (AONB).

We are also making significant changes to the local electricity network owned by Western Power Distribution (WPD) by removing 67km of overhead line. See here for further information.

Hinkley Point 400kV Substation	1,261.00	-200.00	1,061.00	01-04-2017
Hinkley 400kV Substation	0.00	1,670.00	1,670.00	06-12-2024
Hinkley 400kV Substation	0.00	1,670.00	1,670.00	06-12-2025

Evidence of defect and additional costs of AC solutions (2of2)

- The Expansion factor for OHL is 14.083 £/MWkm
- The multiplier for 400kV cable is 10.2
- The Annuity factor is 5.8% (statement of use of system charges)

So the Capex for OHL is 242.81£/MWkm
for Cable is 2,476.67 £/MWkm

Applying the km of line/ cable and the MW for the increased capacity yields the capex for the OHL and the cable:

OHL Capex	26.84£m
Cable Capex	47.98£m
OHL+ Cable Capex	74.81£m

The calculated capex on OHL and Cable is only 9% of the total project capex of £800m, presumably as it does not cover costs of substations, undergrounding and diverting DNO assets, etc etc.

I.e. for Hinkley ~90% of the reinforcement costs are socialised.

This situation should be compared to the approach to HVDC on the Islands where [100%] of the costs are included in the expansion factor and therefore in charges to generation users.

In addition Hinkley Point has –ve generation charges, so it is not contributing to the £800m reinforcement capex, that contribution must come from other users/generators.

Issue	Revision
14	0

This is a copy of the statement provided to Ofgem on 7 March for approval of form under licence condition C4.6.

The Statement of Use of System Charges

Effective from 1 April 2018

Table 1.1: TNUoS Calculation Parameters

Parameter	Value/Basis
Transport model network, nodal generation & nodal demand data	Based upon various data sources as defined in Section 14 of the Connection and Use of System Code (CUSC)
Expansion constant	£14.08310010/MWkm
Annuity factor	5.8%
Overhead factor	1.8%
Locational onshore security factor	1.8
Offshore civil engineering discount	£0.440694 /kW

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Charging of AC onshore vs HVDC to islands

- Onshore AC connections require substations but substation costs are socialised. Imagine the first 275kV circuit built in UK from Tyneside to Strathclyde. This line would require 275kV substations which did not exist before. This is analogous to HVDC requiring converter stations. The onshore AC assets constructed for Hinkley require undergrounding of DNO assets to achieve planning. These costs are socialised and not assigned to the generator concerned, however the cost of undergrounding/subsea installation to the islands required by the physical geography is currently allocated to the island users.
- There is undue discrimination against island users.

More AC substations provide more AC transmission capacity

- Adding substations to the AC network increases transmission capacity even though the costs of these substations are socialised and not added to the expansion constant.
- Take the Pembroke to Walham 400kV circuit as an example. It is the longest 400kV circuit in GB (ETYS2017), however it is proposed to shorten this circuit by turning it into Swansea North substation. This turn-in cost is associated with the substation and is not charged to the expansion factor. The AC work to improve capacity is socialised, whereas HVDC, which provides such long distance transmission capacity in the first place, has the costs of the converter stations (which are equivalents to substations) charged to the expansion factor.

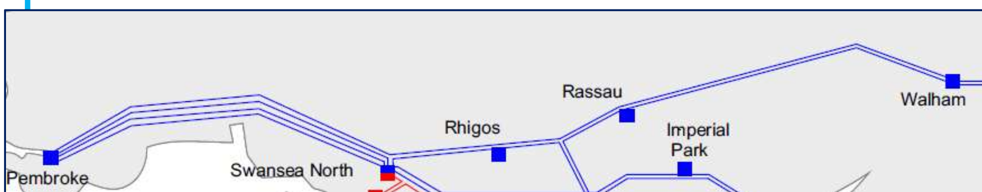

Table B.2.2c - NGET Circuit Changes 2018/19 to 2026/27

Node1	Node2	Year	Status	OHL Length (km)	Cable Length (km)	Circuit Type
PEMB41	SWAN41	2026	Addition	83.975	0.000	OHL
SWAN41	WALH41	2026	Addition	133.452	5.468	parallel Composite
PEMB41	WALH41	2026	Removed	217.727	5.468	Composite

- Compare this situation to a hypothetical HVDC link where a third converter station is added halfway along the link to improve the transmission capacities of the overall system. This third converter station would result in an increased expansion factor for the circuit, with an increase in TNUOS to users at the far end, although there is no benefit to those far end users of the third converter station.

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AC circuits require more assets than just cables or lines in order to function

- AC networks generate and consume reactive power according to their power flow/loading. Series capacitors are deployed to reduce their impedance. Quad boosters are applied to manage the sharing of flows. None of these assets or the substations they sit in are charged in the expansion factor. Also AC networks incur ancillary services costs to manage these issues and deliver the thermal capability of AC lines. These services and costs are not required or incurred for HVDC island links yet the converter stations, which enable these cost savings, are charged in TNUOS, via the expansion factor, which is undue discrimination for HVDC vs AC assets.
- For example, an IEEE Paper by Colin Bayfield of Scottish Power showed that half the costs associated with the Harker to Strathavan 400kV line build in the mid 1990s were associated with the costs of the overhead line, the other half were for substations and stability. Since it was built, a number of other substations have been added along the 400kV line and Series capacitors applied to increase the boundary capacity of the same asset with the same thermal rating.
- HVDC does not require any of these add-ons, so is discriminated against in the charging regime.

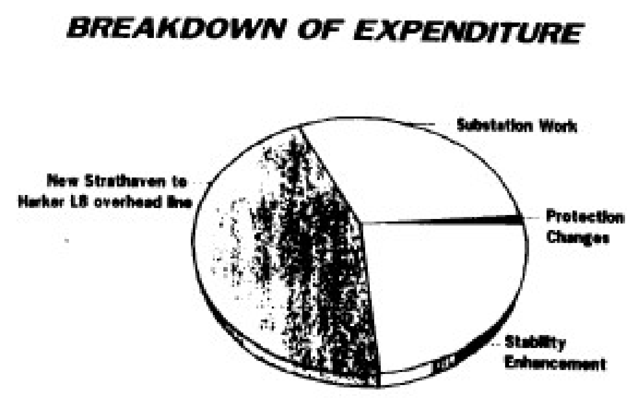

Figure 4

- IEEE paper on cost of new 400kV overhead line - with 50% being non overhead line costs

Optimisation of capacity for lower costs and charges

- OFTO assets are designed and built by offshore developers. The developers control the ratings and costs of these assets and can manage their TNUOS charges as a result.
- Island developers do not control the size or cost of assets, which is determined by the TO, therefore island developers are not able to manage TNUoS charges.
- For example, based on the HVDC cost model developed for Greenlink and Maali interconnector projects, Statkraft have calculated that the additional costs of taking the Shetland HVDC connection from 600 to 800MW is less than 4% for the 33% capacity increase. The larger capacity would reduce TNUOS by a greater amount than the increase in capital cost. The offshore developer can manage and exploit such benefits of scale, whereas the island developer cannot.

HVDC solutions are can have lower capex than AC

- There is an assumption in some quarters that HVDC solutions are always more expensive that AC solutions, however this is not always the case. The competition to replace the Shetland Power Station demonstrated that an HVDC link (with converters and cables) was the most cost effective. We assume that National Grid Ventures, who proposed the HVDC solution, did so because it was more cost effective than using AC.

ofgem Making a positive difference for energy consumers

Consultation on the cost of the new energy solution for Shetland

1.10. SSEN has now completed the competitive process and has informed Ofgem that its preferred bidder is a joint bid by NGSLL and Aggreko, the preferred Shetland New Energy Solution (SNES). The solution involves building a High Voltage Direct Current (HVDC) link between Shetland and mainland GB with a back-up diesel generator on Shetland.

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HVDC island links provide security of supply

- The Shetlands are not connected to the GB grid and the power station requires replacement. A competition to replace the station identified the lowest cost solution as an HVDC link from Shetland to mainland. The cost of the HVDC part of the solution was [£279m] if a transmission link is built to Shetland to enable generation exports, the link will also provide an island supply to replace the power station with a capital saving of [£279m]. This avoided cost should be deducted from the actual cost of the HVDC transmission link before TNUOS charges are calculated.
- The same principle of security of supply applies to other remote islands, and as cost saving information is not to hand for these islands the same %age cost reduction for charging should be applied to other remote islands with HVDC links as for Shetland.

Arbitrary Geographical and historical nature of TNUOS

- It has been shown that for the Hinkley point reinforcements, 90% of the costs are associated with works other than the 400kV overhead lines and cables themselves.
- When the Beauly Denny 400kV upgrade was completed there was a reduction in the northerly TNUOS charges because of the decreased unit capacity costs.
- Both of the above works incurred investment costs but did/will not raise charges commensurately.
- In parts of GB, old and new assets have been built at lower voltages that 400kV for permitting or historic reasons. These lower voltages incur higher local TNUOS charges on generation users, however there is no commensurate reduction in charges for demand users.
- Transmission reinforcements are increasingly expected to involve sections of more expensive underground cable in order to satisfy contemporary visual sensitivities.
- To avoid the arbitrary nature of charges due to historic or geographical reasons a standard expansion factor could be applied to all assets regardless of voltage or type.

Summary of discrimination in HVDC charging

- AC networks require substations to function and transmit power. The substation house switchgear and protection, transformers, reactors, capacitors, Statcoms, series capacitors and quad boosters which are required to deliver power transfer of AC. These assets are not charged to the expansion factors whereas HVDC converters are.
- 50%-90% of the costs of building/reinforcing AC networks, are not included in AC the expansion factors.
- AC networks require ancillary services to operate them including reactive power, dynamic voltage control, inter-tripping etc. These costs re not incurred on HVDC links.
- OFTO developers control the sizing of their assets and can cost optimise, inland generation developers cannot.
- HVDC transmission links provide security of supply on remote islands
- The nature of network charging is somewhat arbitrary, whilst generally cost reflective there are instances when this is not the case. A standard km based expansion factor regardless of circuit voltage or type would remove such idiosyncrasies.

WACMs (workgroup alterative code modifications)

1. Remove all converter station costs from HVDC charging.
2. For Island HVDC charges, recognise the alternatives of making a supply to the islands via distribution rated HVDC and subtract this benefit form the cost before applying TNUOS. As these costs are clear for Shetland use Shetland as the model and apply same %ages to HVDC link to the Western Isles.
3. Given the discrepancies in charging and the historical and geographical accidents and associated costs relating to either: the remote islands; or the densely populated areas of England; or the landscape designations; apply a single global GB expansion factor to all assets: AC and DC; cable and overhead line; and all voltages; to remove these idiosyncrasies.
4. Combine 1&2 above
5. Combine 2&3 above.

THANK YOU

Guy Nicholson, Grid Manager

Guy.Nicholson@Statkraft.com

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