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Project TransmiT: Further consultation on proposals to change the electricity transmission charging methodology

Consultation

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Overview:

Electricity generators and suppliers pay charges for using the electricity transmission network. These charges recover the costs of providing the assets needed to transport electricity across the network. Individual charges are determined using a methodology administered by National Grid Electricity Transmission plc (NGET).

Project TransmiT identified defects in the current transmission charging methodology. This triggered an industry-led process which developed several options for change. In August 2013 we published a consultation and analysis of the impacts of these options, including our initial minded-to position.

We received new information from the consultation process that had not been presented before. This led to our decision in December 2013 to do more work to examine this evidence thoroughly. This consultation provides an update on our position to take account of responses to our last consultation and subsequent analysis that we have undertaken. We are seeking views on this. Our position remains that we are minded to approve the option set out in August 2013, subject to responses to this consultation.

Context

Great Britain's energy sector is facing an unprecedented challenge. This is driven by the need to connect large amounts of new and low carbon generation to the electricity networks to meet climate change targets, while continuing to provide safe and reliable energy supplies at value for money for consumers today and in the future. As a result of the rapidly changing generation mix, networks are going through radical change. Against this background, we launched Project TransmiT to consider if any changes may be required to the electricity transmission charging arrangements.

Associated documents

Project TransmiT: a call for evidence, September 2010, Reference number 119/10
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT

Project TransmiT: electricity transmission charging Significant Code Review launch statement, July 2011
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=141&refer=Networks/Trans/PT

Project TransmiT: Electricity transmission charging arrangements Significant Code Review conclusions, May 2012
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=232&refer=Networks/Trans/PT

Direction to National Grid Electricity Transmission plc in relation to the Significant Code Review under Project TransmiT
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=234&refer=Networks/Trans/PT

Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology. Ref No 137/13
https://www.ofgem.gov.uk/publications-and-updates/project-transmit-impact-assessment-cmp213-options

Project TransmiT: open letters on progress, December 2013 and March 2014
https://www.ofgem.gov.uk/publications-and-updates/project-transmit-update-progress-and-next-steps & https://www.ofgem.gov.uk/publications-and-updates/project-transmit-update-progress-and-way-forward

Documents published as part of the CUSC modification process are available on National Grid's website
http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

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Executive Summary

We consulted on proposals put forward by industry in August 2013. These addressed defects in the existing transmission charging arrangements. At that time our minded-to position was to approve the "Workgroup Alternative Connection and Use of System Code (CUSC) Modification 2" (or WACM 2) option and to implement this in April 2014.

We continue to think that WACM 2 best addresses the identified defects, and therefore remain minded to approve it. This is because it reflects the costs imposed by different types of generators on the electricity transmission network by:

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

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

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

As a result, WACM 2 is a significant improvement to the current approach which only recognises peak security as a driver of transmission investment and assumes that all types of generators contribute to it.

WACM 2 also incorporates solutions for charging for High Voltage Direct Current (HVDC) and island links. In doing so it does not seek to socialise any of the associated converter station costs. We think this is right because we have not been provided with strong enough evidence to avoid targeting the recovery of these costs from the users of the links.

In August 2013, we concluded that WACM 2 was the most cost reflective option presented to us and would drive more efficient decisions by market participants and policy makers. This in turn would create value for consumers. The modelling analysis suggested that implementing WACM 2 could lower consumer bills.

We received a large number of responses to our consultation. We have reviewed them and remain minded to approve WACM 2. But because of the additional evidence and analysis we received, there are two main areas where our analysis has developed since August 2013.

Firstly, we received analysis from one respondent that suggests WACM 2 may result in charges for intermittent generators that are less cost reflective than status quo where the marginal investment is an HVDC line. This is because the cost of HVDC is significantly higher than the cost used to calculate the tariffs using the existing charging principles (which apply to WACM 2 as well as status quo).

We think that significant new investment in HVDC links is less likely than the respondent assumes. We also consider that the range of the costs of future reinforcements means that long run costs are likely to be broadly consistent with those used in the existing methodology. The analysis also shows that WACM 2 would result in charges that were more cost reflective in all other circumstances. We therefore think that potential benefits of greater cost reflectivity for the GB system as a whole outweigh the risks that WACM 2 may result in less cost reflective charges in certain cases.

Secondly, we also examined new evidence as to the impact of implementing WACM 2 on consumers and the power sector as a whole.

We commissioned Baringa to update the impact assessment modelling carried out by NGET (presented in August 2013) for DECC's latest position on electricity market reform. We also recognised that other highly uncertain assumptions had a major impact on results. We therefore looked at two modelling scenarios with one illustrating the impact of also changing other variables such as gas prices. The results of both modelling scenarios show reduced power sector costs under WACM 2. We consider this illustrates the benefits of a more cost reflective charging methodology. The consumer bill impact is heavily influenced by the modelled capacity mechanism. In the modelling period, the impact assessment suggests a rise in consumer bills of between £0.05 and £0.75 from implementing WACM 2.

We consider that the modelling does not give a full picture of the impact on consumers. Modelling the energy market is complex, and made even more so by the capacity market. The modelling does not capture more dynamic effects such as how generators would respond to more stable capacity margins or efficiency gains resulting from of new generators entering the market due to higher profits. In addition, there may be wider sustainability benefits for consumers which cannot be captured in a model. We therefore think that the cumulative impact of these effects would mean that implementing WACM 2 would result in long term benefits to consumers.

We consider it is important to allow generators to respond to any change in the charging methodology within the notification period required by the user commitment arrangements. It is also important to give suppliers sufficient lead time ahead of implementation to avoid them building risk premiums in future for fixed tariff offers to consumers.

We therefore remain minded to implement WACM 2. Our minded to implementation date is now April 2016.

1. Background

Chapter Summary
This chapter provides an outline of the background to CMP213 and an overview of how the rest of the document is structured. There are no consultation questions.

1.1. In August 2013 we issued an impact assessment and consultation on the options to change the transmission charging methodology that had been submitted to us by industry. These options were developed through the Connection and Use of System (CUSC) modification process. This modification is known as CUSC Modification Proposal 213 (CMP213).

1.2. CMP213 is the culmination of a review of transmission charging known as Project TransmiT. CMP213 put forward changes to the transmission charging methodology to develop and assess solutions to address the defects in the existing methodology we identified as part of our Significant Code Review in May 2012.

1.3. This chapter provides an overview of the existing transmission charging arrangements, a summary of the defects that CMP213 seeks to address and a summary of the assessment in our initial consultation and developments since then.

The existing transmission charging arrangements

1.4. Electricity generators and suppliers pay charges for using the electricity transmission network known as Transmission Network Use of System (TNUoS) charges. Individual TNUoS charges are determined using a methodology administered by National Grid Electricity Transmission plc (NGET).

1.5. The charge recovers the costs of the installation, reinforcement, maintenance and renewal of assets by the Transmission Owners (TOs) that facilitate access to and the flow of power across the network. These costs vary by location of the user as well as by how and when they use the network.

1.6. Cost reflective charging targets the costs of establishing and operating transmission infrastructure on the users of the system who impose those costs. This provides a signal to users which enables them to make informed commercial decisions about where to situate new generation and when to adjust or close existing generation. This supports the development of an economically efficient system at a lower cost to the consumer.

1.7. Currently, TNUoS charges are calculated using an investment cost related pricing (ICRP) methodology. There are two components to the tariff. The first is calculated by assessing the impact on the costs of the transmission network of adding a megawatt (MW) of generation or demand at different locations on the system. This provides a cost reflective locational component. The second recovers the costs not captured by this locational component[1] (the 'residual'). This is a non-locational charge.

1.8. The current ICRP methodology also has features designed to enhance the transparency and stability of the tariffs. These are important aspects to reducing barriers to entry and facilitating effective competition. Locational tariffs are calculated using the costs of existing transmission circuits and technologies at current prices. The methodology used to calculate the tariffs also mean that the lumpiness of transmission investment is smoothed away, making them more predictable. It also means they are not based on subjective assumptions about possible future transmission investments.

1.9. In addition, the tariffs are averaged into zones. This provides further tariff stability for the duration of the price control period for which the zones are set.

1.10. These features mean that the investment costs reflected in the charging methodology are an approximation. The methodology produces signals that reflect the (zonal) long run marginal cost (LRMC) of the integrated network on the basis that the cost of future investment will be similar to the cost of rebuilding the existing network at current prices. This approximation is present in both the status quo and all the options we were presented with as part of CMP213.

Defects identified in the existing system

1.11. The cost of investment in the electricity transmission system is driven in the first instance by the planning framework (known as the Security and Quality of Supply Standards or 'SQSS'). The cost of building the network to comply with this framework is the basis for the locational element of the TNUoS charges.

1.12. Until recently, the planning rules used by each TO for identifying the minimum investment required on transmission boundaries[2] were based primarily on the need to maintain system security at times of peak demand. This approach was set out in the SQSS which contained a set of parameters to be used in system planning based on a single 'peak security' background. This was translated in to the current charging approach. By implication it carries the assumption that peak security is the sole driver of transmission investment and that all types of generators contribute equally to it, as they all pay the same tariff within a zone.

[1] Other asset cost categories (e.g. substations and historic investments) and assets which costs are non-locational (e.g. offices and 'spares') are recovered through the residual element.
[2] Although these boundaries can occur anywhere on the transmission system, there are a set of specific boundaries which are commonly used to illustrate the need or otherwise for transmission reinforcement.

1.13. The transition to a low-carbon economy has triggered growth in the volume of intermittent generation connecting to the transmission system. Intermittent generators are not assumed to contribute to peak security for the purposes of the SQSS.

1.14. However, without network reinforcement, more new generation connecting to the system would result in congestion. Congestion is managed through operational intervention taken by NGET in its role as System Operator. This requires constraint payments to be made to affected generation parties. As more generation connects, there is a point when it becomes more economical to build additional transmission capacity to avoid increasing levels of constraints and minimise the total cost of the network. Different plant contribute to constraints to different extents and therefore to different levels of investment to relieve them.

1.15. The SQSS was updated in 2011 to recognise that transmission investment is increasingly being driven by the need to efficiently manage constraint costs. It now recognises the following criteria to be used in deriving the required level of investment in the transmission system:

- **Demand security criterion** – this requires transmission system capacity to be sufficient to meet peak demand without relying on intermittent generation;
- **Economy criterion** – this requires sufficient transmission system capacity to accommodate all types of generators to efficiently meet varying demand. The approach involves deterministic parameters which aim to replicate a generic, GB wide, cost benefit analysis (CBA) that has an appropriate balance between constraint costs and the costs of transmission reinforcement.

1.16. There is also a broader requirement to take into account 'considerations during the course of the year'. This includes considering whether a full CBA is required to justify a particular investment.

1.17. These developments have created a disjoint between the charging methodology and the SQSS. The incremental investment approximated in the charging methodology is currently only based on considerations of peak security. This means that charges are not appropriately reflecting the different costs that users impose on the system. The proposed change in the charging methodology seeks to better align the locational signals provided by the tariffs to the updated planning framework.

1.18. In addition, the current methodology does not cater for:

- High Voltage Direct Current (HVDC) links that will run parallel to the onshore Alternating Current (AC) network.
- Subsea radial transmission links from the mainland to the Scottish islands.

The industry governance process

1.19. Industry developed different solutions to address these defects and submitted them to us for approval. We received the Final Modification Report from industry on 14 June 2013. The CUSC Panel's recommendation, carried by a majority, was that 8 of the 27 options that were presented to them by the CMP213 Workgroup[3] better facilitated the CUSC objectives than the status quo. Details of the options can be found in our August 2013 consultation.

Our August 2013 consultation

1.20. In August 2013 we said we were minded to accept one of the recommended options known as "WACM 2", subject to the responses to the consultation. This was supported by the modelling analysis provided by NGET and our qualitative assessment. We thought WACM 2 best addressed the identified defects because it:

- Splits the locational element of the charge levied on generators into two elements. The 'Peak Security' tariff and the 'Year Round' tariff. This better aligns with the assumptions in the SQSS, and therefore the drivers of transmission investment.

- Recognises that different generators impose different costs on the transmission network. Under WACM 2, all generators would pay the Year Round tariff and plants that operate more frequently would pay charges reflecting their increased likelihood of triggering (or avoiding) constraints costs. This would be achieved by using a generator's load factor (a measure of how much a plant generates) as a proxy for its impacts on constraints and hence transmission investment. Intermittent plant (eg wind) would not pay the proposed Peak Security tariff.

- Recognises that the mix of generation behind a transmission boundary affects constraints and therefore investment. In particular, zones dominated by low carbon plant tend to drive more transmission investment because low-carbon is less able to efficiently 'share' transmission network capacity as:

    - low-carbon plant tend to run simultaneously (eg when the wind is blowing)

    - it is more expensive to curtail the output of renewable generation due to the interaction with government low-carbon support arrangements (ie constraint payments reflect the lost subsidy payments from not generating) compared to other forms of generation.

1.21. We also considered WACM 2 to be an improvement to the existing approach as it incorporated solutions to charging for HVDC links that will parallel the GB transmission system, and for potential island transmission links which use subsea

[3] The workgroup comprised of a number of industry specialists from a broad range of users.

cable technology. These are not catered for by the current methodology. Under WACM 2, all of the associated HVDC converter costs are included in the locational element of the tariff.

1.22. We therefore set out in August 2013 that we thought that WACM 2 best facilitates the relevant CUSC objectives compared with the status quo and other options presented. We also thought it was consistent with and best furthered the Authority's statutory duties. This was based on the impact assessment modelling carried out and other qualitative evidence. These views, and a proposed implementation date of April 2014, were set out as part of our impact assessment and consulted upon.

1.23. Our consultation closed on 10 October 2013 and we received a significant level of responses. This included alternative impact assessment modelling commissioned by one party and new arguments that had not been presented before. As a result of this, we told industry in December 2013 we needed more time to give it full consideration.

1.24. In March 2014 we published an update on progress and next steps for CMP213.[4] We said that we would consult on new evidence received in the responses to the consultation. We also said that were we to approve one of the modification options we were minded to implement in April 2016.

Further work

1.25. Since December 2013 we have appointed external consultants, Baringa, to carry out additional modelling to respond to criticisms raised of the impact assessment modelling undertaken by NGET. Details can be found in Baringa's report published alongside this document.

1.26. We have engaged with the parties who provided evidence and arguments which questioned the cost reflectivity of the proposals.

1.27. We have received further submissions from industry since December in support of issues raised in original responses to the consultation. We have reviewed this analysis and information. We have published these submissions alongside this document. These include:

- "Project TransmiT: update on progress and next steps", 6 February 2014. Prepared by SSE.
- "CMP213 Project TransmiT – ScottishPower additional memorandum", 7 February 2014. Prepared by ScottishPower.

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[4] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-update-progress-and-way-forward

- “Review of the NERA/Imperial College London report on the impact of the WACM 2 charging model” 27 February 2014. Prepared for SSE by Oxera.
- “Review for SSE of Poyry’s report to Centrica Energy”, 5 March 2014. Prepared by Phil Baker of Exeter University.
- “Assessing the cost reflectivity of alternative TNUoS methodologies”, 7 March 2014. Prepared for RWE npower by NERA & Imperial College London.

Additional consultation

1.28. We have reviewed our previous minded to position against the new evidence and analysis we have received in response to the August 2013 consultation. This document sets out:

- Our assessment in Chapter 2 of the two main areas of new evidence. These are areas that have resulted in us relying on analysis that was not considered in reaching our decision on whether to accept WACM 2 in our August 2013 impact assessment.
- A fuller review in Appendix 2 of respondents’ views on the analysis and evidence presented in last year’s consultation.
- Our minded to position remains to approve WACM 2.
- Our minded to position is to implement in April 2016.
- Our final decision remains dependent on our analysis of responses to this further consultation.

1.29. This document does not reiterate the full analysis of all the CMP213 options laid out in our August 2013 consultation.

1.30. It marks the start of a four week consultation period during which respondents are invited to provide feedback on our analysis and minded to position. Details on how to respond to this consultation, including contact details for any queries can be found in Appendix 1.

2. Assessment of additional evidence

Chapter Summary
Here we summarise the new analysis and give an overview of our current thinking on the proposals to change the TNUoS methodology.

Consultation questions:
Question 1: Do you agree with our interpretation of benefits to consumers of implementing WACM 2, including revised impact assessment modelling?
Question 2: Do you agree that the revised impact assessment modelling captures concerns raised during August 2013 consultation about the NGET modelling?
Question 3: Do you agree with our minded-to position in light of new evidence discussed below and the responses to the consultation set out in Appendix 2?
Question 4: Do you agree with our minded-to position to implement in April 2016?

2.1. In our August 2013 consultation, we were minded to approve the option known as WACM 2, rather than retain the status quo or approve one of the other options presented. This was because we considered WACM 2 best facilitates the relevant CUSC objectives and best furthers our wider duties and principal objective to protect consumers.

2.2. Our conclusion that WACM 2 best facilitates the CUSC objectives is summarised as follows.

- WACM 2 results in more **cost reflective** charges because the charges differentiate between investment driven by peak security and investment driven by managing constraint costs. It also recognises that the generation mix in a zone affects charges, as well as reflecting all HVDC costs to the users who triggered the investment.

- **Effective competition** is increased under WACM 2 because the benefit from the improvement to cost reflectivity reduces discrimination, and does not adversely affect siting decisions. We did not think this effect was outweighed by the additional complexity of the TNUoS tariff calculation or that the redistribution of costs under WACM 2 was disproportionate.

- WACM 2 best incorporates the **developments** in the transmission licencees' transmission businesses because it best incorporates the developments of HVDC and island links as well as best taking into account the changing generation mix.

2.3. We also set out the evidence we used in reaching the conclusion that WACM 2 better facilitates the Authority's principal objective of protecting the interests of existing and future consumers. These interests include the reduction of greenhouse gas emissions, security of supply and the requirements of applicable European Law as set out in Article 36(a) of the Electricity Directive. We considered that a more cost reflective methodology is in the long term consumer interest. We thought that WACM 2 provided long term sustainability benefits and that, in the long term, the impact assessment modelling showed that consumers would benefit from reductions in their bills. However, at that time we noted that certain assumptions were influencing the results of the modelling, and that this benefit may be overstated.

2.4. More detail on our conclusions in the August 2013 consultation is set out in that document.

2.5. We remain minded to approve WACM 2. However, responses to the consultation and the additional impact assessment modelling undertaken have meant there are two key areas where our analysis has developed since August 2013. These are discussed in this chapter.

2.6. The issues below are not the only ones raised in responses to the consultation. We have considered these and our analysis is laid out in Appendix 2. However, none of these have persuaded us to further depart from the arguments we previously described in support of the minded-to position in August 2013.

2.7. The two main areas of new evidence and analysis relate to:

- evidence of the cost reflectivity of WACM 2 compared to status quo in the case of HVDC links; and
- evidence of the potential impact of the change on the sector and on consumers.

Cost reflectivity in the case of HVDC links

2.8. In our August 2013 consultation, we said that we considered WACM 2 was more cost reflective than the status quo because it better reflected the investment cost drivers prescribed in the planning framework, the SQSS. Most respondents were supportive of the inclusion of the dual drivers of transmission investment contained in the updated SQSS into the transmission charging methodology. Some respondents challenged the evidence and analysis we presented in support of this. Our view remains that WACM 2 is more cost reflective than the status quo. In arriving at this view, we consider that that the use of a generator’s annual load factor and the proposed sharing methodology in the calculation of the Year Round tariff is an appropriate proxy for the incremental cost of transmission network investment.

2.9. However, we note one response to the consultation that suggests that in zones where the next investment technology is HVDC, charges under WACM 2 may be less cost reflective than the status quo. We have considered our minded-to position in light of this.

Assessing cost reflectivity using a measure of long run marginal cost (LRMC)

2.10. NERA and Imperial College London (on behalf of RWE npower) ('NERA/ICL') argue that cost reflectivity must be assessed against a quantitative benchmark. It argues that as the charging methodology is seeking to reflect the cost of transmission investments, then it should reflect the LRMC of transmission reinforcement. So, any proposed changes to the transmission charging methodology should be assessed against a measure of LRMC.

2.11. NERA/ICL constructed a measure of LRMC and provided analysis that compared the tariffs under status quo and WACM 2 to this yardstick. The method of calculation is described in its report entitled "Assessing the cost reflectivity of alternative TNUoS methodologies" published alongside this consultation. Baringa's report also contains further analysis of NERA/ICLs approach.

2.12. The modelling is not conclusive. Neither set of tariffs is a good match for LRMC for all plant types in all years. However, the analysis does suggest that charges under WACM 2 for wind generation in Scotland are not as close to LRMC as those under status quo once the need for HVDC bootstraps to reinforce the transmission system between Scotland and England is triggered. NERA/ICL note that this is because WACM 2 reduces the locational spread of TNUoS charges faced by wind generators as compared to status quo. This is because of the use of the annual load factor in the calculation of the Year Round element of WACM 2 tariffs.

Our analysis

2.13. The current ICRP methodology approximates the incremental cost of transmission reinforcement based on the cost of building the existing circuits at current prices. This is used to calculate a tariff at each node which is then averaged within zones.

2.14. HVDC technology has a unit cost that is significantly higher than the cost of the circuits/cables that comprise the existing AC network. The NERA/ICL model assumes that the marginal reinforcement required on the network between Scotland and England is an HVDC bootstrap. The impact of an incremental MW of generation in its model is at a cost equal to the incremental cost of HVDC technology for the entire modelling period. Hence, future network reinforcement costs significantly diverge in these zones from the costs used in the calculation of status quo and WACM 2 tariffs in the ICRP methodology. In NERA/ICL's analysis, this is driving a greater divergence from the measure of LRMC for WACM 2 tariffs for wind generators in these zones than for status quo. This suggests that in these zones, WACM 2 would result in tariffs for wind generators that are less cost reflective relative to the status quo.

2.15. However, we note that in the majority of cases the NERA/ICL analysis suggests that WACM 2 is closer to the measure of LRMC than status quo. This suggests that WACM 2 is actually more cost reflective than status quo. We have therefore considered both how often it is likely that the marginal investment will be HVDC and how large the increased differential is likely to be.

2.16. The ICRP methodology makes assumptions about investment costs that mean in some circumstances tariffs may not fully reflect the costs of the actual next investment at a particular location. A model that reflects whether the actual network would need to be reinforced to accommodate a particular change and the actual nature and cost of that future reinforcement may in these circumstances be more cost reflective.

2.17. However, we consider that in a significant majority of cases the current ICRP methodology will produce long run charges that are an appropriate approximation of the long run costs users impose on the transmission system. We consider that the type of future investment to be uncertain. There is likely to be a broader range of investments than assumed by NERA/ICL in its modelling. Some of this investment will be at a cost lower than the cost of the equivalent existing network at current prices. We also consider that fewer HVDC links may be built than currently being considered which gives further weight to this argument. Under the Strategic Wider Works process put in place under the RIIO-T1 price control, TOs must demonstrate that its proposed investment is the most efficient option. This will not always be an HVDC link as other alternative investment options may deliver a better result.

2.18. In addition, we continue to believe that WACM 2 is correcting a defect in the system by better aligning the TNUoS charging methodology and the updated SQSS. We believe that the use of a single locational charge for electricity generators does not better align to the ICRP methodology and the updated planning framework set out in the SQSS. This is supported by NERA's analysis which shows that in the majority of cases WACM 2 tariffs are closer to LRMC than the status quo.

2.19. We have looked at whether we could justify the time and cost of the modelling needed to develop our own view of LRMC. Deriving LRMC requires subjective projections about future levels and types of generation and the required level of transmission reinforcement. These projects are highly uncertain but have a large impact on results. The assumptions made by NERA/ICL in these areas drive its calculation of LRMC. In carrying out our own modelling, we would be required to develop our own methodology and make our own simplifying assumptions. As this would be open to debate, we do not believe that carrying out our own modelling of LRMC would give any more weight to the existing evidence.

Initial conclusion

2.20. On balance, we think that the potential benefits of greater cost reflectivity for the GB system as a whole outweigh the risks that WACM 2 may result in less cost reflective charges in certain circumstances. We think that this risk is considerably lower than that implied in the NERA/ICL modelling described above. We also consider that there is the potential to mitigate this risk if it does materialise through other modifications to the transmission charging arrangements.

2.21. We are also not persuaded by any of the arguments included in the consultation responses which seek to demonstrate that WACM 2 is less reflective of the impact different users have on the transmission system than the current ICRP methodology. Our views are set out in more detail in Appendix 2.

2.22. In addition, we continue to think that WACM 2 better promotes competition and better reflects developments in the transmission licences' transmission businesses for the reasons set out in our August 2013 consultation.

2.23. **We therefore continue to think view that WACM 2 better facilitates the CUSC objectives than the status quo.**

Assessment of consumer benefit

2.24. A more cost reflective charging methodology should lead to a more efficient energy system overall and this will, in the long term, lead to benefits for consumers. In our August 2013 consultation we laid out qualitative and quantitative evidence supporting this view.

2.25. We showed the monetised benefits in the August 2013 consultation based on the impact assessment modelling prepared by National Grid. In the consultation, we noted that the way contracts for difference (CfDs) and the capacity market were modelled had influenced results. This was leading to volatile capacity margins driving differences in wholesale prices. In addition, higher renewable generation in status quo as compared to WACM 2 was driving differences in the results between the two scenarios.

2.26. These issues above we also raised by respondents to the consultation. In addition, respondents also highlighted:

- Possible distortions to generation dispatch
- The impact of the low carbon generation mix
- The need for additional sensitivity analysis.

2.27. The impact assessment modelling had been constructed to reflect an understanding of the UK government's most up to date Electricity Market Reform ('EMR') proposals. However, given the responses to the consultation and the separate impact assessment modelling presented by one respondent, we considered that it was prudent to update the modelling to reflect the further detail on the likely scope of EMR and the proposed capacity mechanism that had become available. This work is discussed below.

2.28. When assessing the potential benefit to consumers, we have also considered what factors could not be modelled but would have a long term impact on the actual monetised benefits.

Revised impact assessment modelling results

2.29. Given the uncertainty of many of the wider assumptions (such as future gas prices) used in the modelling, we have considered two main modelling scenarios. As a result we have considered a possible range of results as opposed to a single case. The first is based on the set of assumptions used in the August impact assessment carried out by NGET but updated to more accurately reflect the DECC's latest policy on the capacity mechanism (the Original Case).

2.30. The second scenario applies the above revisions and adjusts for the assumptions shown in Table 1 below (the Alternative Case).

Table 1: revised modelling assumptions

Assumption	Original Case	Alternative Case
Gas and coal prices	DECC updated energy and emission projections: 2012[5]	**Lower gas price** to reduce generation costs of gas below that of coal (gas prices are 20% lower than Original in 2015 & 2016, 15% from 2017 to 2020, and 10% after 2020. Coal price increased by 20% in 2015 and 2016)
Generation mix (approach to meeting approximately 100g/kWh carbon intensity in 2030[6])	Nuclear: 15.2 GW CCS: 9.2 GW Onshore wind: 11.9 GW Offshore wind: 10.9 GW	Nuclear: 12.0 GW CCS: 7.0 GW Onshore wind: 14.1 GW Offshore wind: 18.7 GW
Interconnector contribution to de-rated margin	**0%** (i.e. interconnectors do not contribute to required capacity in Capacity Market)	**75%** (this represents a case in which the majority of interconnector capacity can be relied upon at times of system stress reducing the capacity requirement accordingly)

2.31. More detail, and the results of other sensitivities are shown in Baringa's report published alongside this document. The key results are shown in Table 2 and briefly summarised below.

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[5] https://www.gov.uk/government/publications/2012-energy-and-emissions-projections

[6] Nuclear and Carbon Capture and Storage (CCS) levels in the Original Case were developed by the CMP213 working group. In the updated modelling the timing and location of Nuclear and CCS is exogenous to the model. In the Alternative Case, a greater proportion of renewables has been assumed after 2020 by broadly mirroring the assumptions made by DECC regarding offshore and onshore wind deployment to 2030 in its Updated Energy Projections (UEP). There is correspondingly less CCS and nuclear to achieve a similar power sector carbon intensity of around 100 g/kWh by 2030.

2.32. **Power sector costs**: This represents the overall impact on the system of implementing WACM 2. Overall, the results are showing a small positive impact from WACM 2. There is a small dis-benefit from WACM 2 in the period to 2020 under both Original case (-£115m) and Alternative case (-£31m). After 2020, both cases demonstrate a net benefit of £184m and £99m respectively. These differences are much smaller than in the NGET modelling that underpinned our August impact assessment, reflecting the fact that differences in renewables build have been eliminated with the enhanced modelling approach. These cost differences are now mainly driven to the location of plant on the system with more renewable development on higher yielding sites under WACM 2. The benefits of this more than offset the higher transmission costs of building more transmission in Scotland.

Table 2: Cost Benefit Analysis

Expressed as a difference from status quo in NPV[7] terms (2011)		Original Case		Total	Alternative Case		Total
		2011-20	2021-30		2011-20	2021-30	
Power sector costs	Generation costs	-18	-607	-625	-19	-103	-122
	Transmission costs	38	169	207	0	86	86
	Constraint costs	99	339	438	55	-69	-14
	Carbon costs	-4	-85	-89	-5	-14	-18
	Impact on power sector costs	**115**	**-184**	**-69**	**31**	**-99**	**-68**
Consumer bills	Wholesale costs	51	308	359	212	65	277
	Capacity payments	114	630	774	13	213	226
	BSUoS[8]	50	169	219	27	-34	-7
	Transmission losses	38	131	169	41	31	73
	Demand TNUoS charges	0	28	28	-30	40	10
	Low carbon support	-106	-382	-489	-97	-417	-514
	Impact on consumer bills	**147**	**884**	**1,032**	**167**	**-102**	**65**
	Estimated average annual consumer impact[9]	**£0.19**	**£1.46**	**£0.75**	**£0.22**	**-£0.17**	**£0.05**

Positive numbers (black) represent cost increases under WACM 2 relative to the modelled version of status quo. Negative numbers (red) represent a decrease in costs.

[7] NPV – net present value
[8] BSUoS – balancing services use of system charges.
[9] This is the levelised impact on consumer bills. The NPV of the total consumer cost impact is divided by the NPV of the demand and adjusts to reflect average domestic consumption.

2.33. **Consumer bill impacts**: The economic benefit from WACM 2 that is illustrated by lower power sector costs is not being translated to a consumer benefit in the period to 2030 under either scenario in the model. Under the Original Case the model shows a consumer dis-benefit from WACM 2 of £1,032m to 2030, with additional costs in both periods. Under the alternative scenario, there is a small consumer dis-benefit from WACM 2 of £65m to 2030 but a consumer benefit of £102m in the period 2020-2030. For the whole modelling period, the modelled impact is equivalent to an increase in annual consumer bills of between £0.05 (in the Alternative Case) and £0.75 (in the Original Case).

2.34. In both cases, the modelled consumer dis-benefit is being driven by the interaction with the simplified version of the capacity mechanism modelled by Baringa. There are two offsetting effects resulting from this. First, in the capacity mechanism the level of the capacity payment for all plant is set by the marginal plant bidding in the capacity auction. In the Baringa modelling, the marginal plant is located in southern areas of GB where TNUoS charges increase under WACM 2. This exerts an upward pressure on the bids of marginal plant in the modelled version of the capacity market to compensate, which causes a higher capacity price and higher resulting wholesale prices. This increases costs for consumers relative to the modelled version of status quo. The net result depends on the marginal impact on prices, and the volumes of capacity which are exposed to the changing price.

2.35. The second effect is through low carbon support. Low carbon support payments decrease under WACM 2 by £489m to 2030 under the Original Case and by £514m in the same period under the Alternative case. Any increase in wholesale prices is offset by lower subsidy payments. Payments under the CfD are lower when wholesale prices are higher as less 'top up' is needed. In addition, because WACM 2 lowers the cost for onshore and offshore wind generators, this lowers the CfD strike price which reduces the low carbon support costs.

Interpretation of additional modelling results

2.36. We have considered whether the additional evidence set out above is consistent with the modification furthering our primary objective of protecting the interests of current and future consumers. This includes evidence of both monetised and non-monetised costs and benefits.

2.37. Monetised costs and benefits were assessed using the impact assessment modelling first prepared by NGET for the August 2013 consultation and then updated by Baringa. The modelling was updated because volatile capacity margins in previous modelling made comparison between status quo and WACM 2 difficult. The revised modelling has addressed these issues. We now consider that the modelling more reliably reflects the relevant inputs and interactions to the extent it is possible to do so in a modelling exercise. The results therefore provide an illustration of the potential range of impacts of implementing WACM 2. However, importantly, as discussed below the modelling cannot capture all the factors that will influence the results in reality. While we recognize that alternative modelling methodologies and assumptions give rise to different results (as demonstrated by the alternative modelling presented by one respondent to the consultation) we believe that our modelling is balanced. Quality assurance work has confirmed that the modelling methodology has been implemented correctly[10].

2.38. While we have used the modelling to help us to understand the effects of implementing WACM 2, it can only tell part of the story. It is not possible to capture the complexity of the energy market and how generators responded to changing signals and effects in a single model. This makes modelling the energy market in an impact assessment difficult. It is complicated further by the introduction of a capacity mechanism, the detail of which is yet to be finalised. We have seen in the modelling that this has a strong effect with small changes in assumptions producing very significant impacts on results. We also have no evidence to help us to understand how generators short term and long term responses to these changes will influence results in reality. DECC also recognises the uncertainty around generator behaviour following the introduction of the capacity market. While we have always believed that modelling of this kind is illustrative, this additional uncertainly strengthens the view that we should not consider results as definitive but as part of wider range of evidence to look at collectively.

Interpreting results from modelling of monetised costs and benefits

2.39. In both scenarios, the results show a small reduction in power sector costs under WACM 2. We think this illustrates the benefits of improved cost reflectivity. WACM 2 unlocks higher yielding renewables sites, particularly in Scotland. The selection of more efficient sites offsets increases in transmission costs arising because sites are further from the main centres of demand.

2.40. This is not fed into reductions in consumer bills in the modelling as the results are mostly being driven by the interaction with the capacity mechanism. The modelling results show that WACM 2 drives higher capacity payments because southern plant, who experience higher transmission charges under WACM 2, are the marginal plant which set the price in the capacity auction. However, there are dynamic effects that are discussed further below which are not captured by the modelling. These are likely to increase the benefits of WACM 2 relative to status quo.

2.41. We think that the modelling of power sector costs is likely to be a more accurate illustration of the impact of WACM 2 on the sector as a whole than the results for consumer benefit. Modelling consumer benefit relies on the interaction with the capacity mechanism and it is uncertain how the introduction of this mechanism will drive behaviour. The modelling of power sector costs does not rely on assumptions about this.

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[10] The quality assurance work has been carried out by Lane Clark Peacock. Its report is presented alongside this consultation.

Dynamic effects not modelled

2.42. Higher wholesale prices combined with lower costs shown in the modelling of power sector costs suggests that generators experience higher profits under WACM 2 but, the modelling does not consider how generators might respond to this. We consider higher profits will in the long term lead to existing generators choosing to stay open and/or new entrants to the market. This is likely to lead to lower wholesale prices through efficiency gains and greater competition in the capacity auction, resulting in lower capacity payments. We therefore consider in the long term that the differential in consumer’s bills between WACM 2 and the status quo is likely to be reversed or reduced.

2.43. Moreover, modelling cannot fully take account of other long term effects. In particular, it becomes increasingly more difficult to make meaningful assumptions about factors influencing the market over the longer term (such as policy development or market behaviour). It is also difficult to draw any conclusions using the existing modelling about likely benefits or costs post 2030, the end of the modelling period. But as WACM 2 results in more cost reflective charges, we consider this will bring benefits not captured in the modelling both within the period and beyond it. We would expect to see current and future generators responding efficiently to more cost reflective charges and to any short term increase in profits. This would give policy makers a clearer picture of the market to make efficient decisions and supports the long term efficiency of the energy market. For instance, we consider that the sustainability benefits of WACM 2 discussed further below would support policy makers to develop mechanisms in delivering long term renewables targets at lower cost.

2.44. Finally, the effects in the modelling are driven by assumptions about the marginal plant in the capacity mechanism. This is assumed to be conventional generators in the south in the model. The results are very sensitive to this assumption and any deviation from this affects the modelling results. We have also considered whether there are likely to be other responses that might influence the way in which the capacity market is driving results. The alternative scenario shows that the need to procure less capacity through the capacity market is likely to reduce the modelled impact of implementing WACM 2. We consider that similar effects could be achieved through the use of demand side response (DSR). The participation of DSR in the capacity market is not currently fully captured in the modelling although we are aware that DECC intends to make DSR an important part of managing security of supply.

Non-monetised benefits (wider sustainability benefits)

2.45. As well as the dynamic effects not been included in the modelling, there may be other benefits that cannot be monetised to be included in a model.

2.46. Our examination of whether WACM 2 furthers the interests of consumers includes considering their interests in the reduction of greenhouse gases. While the policy tools for incentivising and delivering low carbon generation sit primarily with government, looking at how implementing WACM 2 may support this is consistent with our objectives.

2.47. The modelling demonstrates that implementing WACM 2 increases the likelihood of meeting renewables targets for a given low carbon support budget. This can be seen in the lower CfD strike prices under WACM 2. Tariffs are lower under WACM 2 in Scotland, where the potential for renewable generation is high. As these sites generally have higher yields, less overall development should be needed to achieve targets. This could support the long term government policy to deliver increasing amounts of energy from renewable sources and to achieve carbon targets.

2.48. In addition, meeting long term renewable targets (eg beyond 2030) will require more renewable technology and incentives for renewable developers to innovate and develop their technologies (such as tidal and marine technology). The broader range of renewables technologies that might be developed under WACM 2 contributes to benefits in terms of energy mix.

Initial conclusion on consumer benefit

2.49. We have reviewed all the evidence of the potential for monetised and non-monetised benefits. Although the impact assessment modelling does not present clear evidence that the monetised benefits of WACM 2 outweigh the costs, we consider that the cumulative impact of factors not included in the modelling would reverse this effect in the long term.

2.50. Overall, we think that the actual impact of implementing WACM 2 is likely to be long term benefits to consumers not all of which have been captured in the impact assessment modelling. **We therefore consider that implementing WACM 2 is in line with our statutory duty to protect the interests of current and future consumers.**

Conclusion

2.51. We remain minded to approve WACM 2. We are of the view that this best facilitates the relevant CUSC objectives because it results in the most cost reflective charges, increases effective competition compared to the status quo and best incorporates developments in the transmission licencees' transmission businesses.

2.52. We are also of the view that because WACM 2 should in the long term result in benefits to consumers, it better facilitates the Authority's principal objective.

2.53. If we approve, we would be minded to implement in April 2016.

2.54. If we approve earlier, parties would not be able to adjust their agreed capacity in response without incurring penalties. Therefore we do not consider that there is any benefit in an earlier implementation date. In addition, we consider there to be a cost associated with an earlier implementation date. If we do not allow parties to respond to the changes ahead of implementation, they could increase hurdle rates for future generation investment if they have greater uncertainty about their ability to respond to future changes. This could adversely affect competition in the generation market and harm consumers. Earlier implementation could lead to suppliers including greater risk premia in their fixed tariff offers to consumers if they are not given sufficient lead time ahead of significant changes. This could increase costs to consumers.

3. Next steps

3.1. This consultation seeks views on the additional information, our further assessment, and our initial views on the way forward.

3.2. **Responses to our consultation should be submitted to us by 27th May 2014.** Details of how to submit a response are included in Appendix 1.

3.3. We will hold a stakeholder event on Tuesday, 6th May 2014 to give stakeholders an opportunity to comment on the outcomes of the additional modelling work and the views we are consulting on. The event will be held at Regus Victoria, Portland House, Bressenden Place, Victoria, London, SW1E 5RS. An invitation to the event has been published alongside this consultation.

3.4. The Authority will consider any responses to this consultation before reaching its final decision. We expect to reach a final decision later this year.

Appendices

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Appendix 1 – Consultation responses and questions

1.1 Ofgem would like to hear the views of interested parties in relation to any of the issues set out in the document.

1.2 We would especially welcome responses to the specific questions set out at the start of Chapter 2.

1.3 Responses should be received by 5pm on 27th May 2014 and should be sent to:

Catherine Williams, Head of Commercial Regulation – Electricity Transmission
Ofgem
107 West Regent Street
Glasgow
G2 2QZ

Tel: 0141 341 3979
email: project.transmit@ofgem.gov.uk

1.4 Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5 Respondents who wish to have their responses remain confidential should clearly mark the documents to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

Question 1: Do you agree with our interpretation of benefits to consumers of implementing WACM 2, including revised impact assessment modelling?

Question 2: Do you agree that the revised impact assessment modelling captures concerns raised during August 2013 consultation about the NGET modelling?

Question 3: Do you agree with our minded-to position in light of new evidence discussed below and the responses to the consultation set out in Appendix 2?

Question 4: Do you agree with our minded-to position to implement in April 2016?

Appendix 2 – Views of respondents to August 2013 consultation

1.1. We received a wide range of views on our minded to position and the underlying analysis supporting it. This section sets out a summary of those views and our response to them. These are grouped as follows:

- Cost reflectivity
- NGET's modelling presented in our August 2013 impact assessment
- Consistency, non-discrimination and complexity
- Treatment of HVDC and island links

1.2. The responses to the consultation are published on our website.

Cost reflectivity

Respondents' views: translation of the SQSS planning rules.

1.3. Some of the respondents felt that the WACM 2 methodology (and other applicable CMP213 options featuring a dual background) will not produce tariffs that have the desired effect of reflecting the drivers of network capacity required by the SQSS. The following points were raised in support of this view:

- the Year Round tariff component does not resemble the criteria "under conditions during the course of a year of operation" in the SQSS
- the generation background used in the determination of the Year Round tariff element of WACM 2 is based on demand conditions that reflect peak conditions. They argued that this is inconsistent with an approach seeking to reflect "year round" conditions.

1.4. One respondent went further to suggest there is no evidence as to which driver is of security is "binding" and presented analysis that charges computed using the WACM 2 methodology are not cost reflective of the expected investment costs derived from the Economy criterion. The same respondent went on to observe that the deterministic rules of the SQSS tend to prescribe investment slightly above the optimum emerging from the full CBA[11], implying that the "binding driver" of investment is the minimum Economy requirements. Another comment received on this topic contended that the primary driver for reinforcements should be the

[11] Appendix 4 of the GSR009 Amendment report submitted to the Authority (April 2011).

Demand Security criterion with the Economy criterion being used to justify investment over and above that.

Our views

1.5. We think there is a misunderstanding in the way in which some respondents have understood the alignment of WACM 2, in particular the Year Round tariff element, to the SQSS and the way in which planning is carried out in reality using the SQSS framework. We support NGET's interpretation of the SQSS and its translation into the TNUoS methodology under CMP213.

1.6. The purpose of WACM 2 is to update the charging methodology to reflect how different users have a different impact on the transmission system. WACM 2 uses a generator's output as a proxy for this impact, represented by a generators annual load factor (ALF) in the calculation. This reflects the principle that generators with a high output typically drive higher constraint costs and therefore trigger more investment.

1.7. NGET have confirmed our understanding of the SQSS. This is as follows:

- The two deterministic rules in the SQSS reflect a set of pre-determined requirements to establish the extent to which network reinforcement is required. The first of these only consider the requirements to reinforce the network based on times of peak demand. The second of these, the Economy criterion, has been developed as a representative 'snapshot' of the required level of efficient transmission investment that would be derived from a cost benefit analysis (CBA). This is in addition to that required for peak demand and is the level of investment required to efficiently manage constraint costs.

- The deterministic rules result in a reasonable proxy of the aggregate boundary flow and level of reinforcement across GB. However, they cannot capture specific regional circumstances. Therefore, the SQSS also provides for consideration of 'conditions in the course of a year of operation'. This recognises that a full CBA may be required in reality and that larger investments require more than a single 'snapshot' study to establish their justification.

1.8. Both the Economy criterion and 'conditions in the course of a year of operation' incorporate a CBA. This is an economic assessment weighing up the cost of current and future constraints against investment costs. The results are influenced by the output of generators behind boundaries and the plant mix in that area. This is consistent with the use of ALF and the sharing factor used in calculating the Year Round tariff under WACM 2. We therefore consider that WACM 2 is consistent with the SQSS.

1.9. The SQSS does not indicate the volume of investment driven by either criterion and does not indicate that the primary driver for reinforcements should be peak demand.

1.10. We consider one respondent to have provided incomplete analysis in reaching the conclusion that WACM 2 is less cost reflective if the "binding driver" of investment is the minimum Economy requirements. This is because it failed to compare both WACM 2 and status quo to costs of derived from the Economy criterion.

Respondents' views: use of annual load factor

1.11. WACM 2 proposes to use the historical 5 year average ALF to derive the Year Round element of the tariff as a proxy of the broad impact of individual users on transmission investment requirements. A number of comments were received from a range of stakeholders in support of this. These comments can be summarised as follows:

- The use of a load factor in this way, although a simplification, provides a reasonable indication of the broad impact of individual plant characteristics on transmission investment requirements when planning network capacity in accordance with the SQSS.
- NGET's analysis in the CUSC Panel's Final Modification Report (FMR) provides evidence of a correlation between load factor and incremental constraint costs across GB.

1.12. In contrast to the above points, there were some respondents who commented on perceived weaknesses associated with the use of ALF under WACM 2.

1.13. These respondents cited a range of factors in support of their view:

- The evidence of the linear relationship between incremental constraint costs and load factor is flawed. They do not believe that the use of ALF in the Year Round element of the tariff is an appropriate proxy for the impact of users on the transmission network.
- Generators should not expect to receive any load factor "dilution" to the Year Round tariff element where sharing does not appear likely to be a real phenomenon (e.g. when there is 0% low carbon generation).
- Applying ALF would represent an attempt to be "more cost reflective" than the SQSS, and this is not a legitimate objective for the TNUoS methodology.

- The use of load factor will place the charging arrangements in contravention of standard licence condition C26[12] which requires that constraint costs be recovered through a uniform £/MWh charge without regional variation.

1.14. Respondents also noted that there may be particular circumstances where the use of ALF to calculate the Year Round tariff would lead to peverse results.

1.15. One respondent made the general observation that in zones dominated by wind generation, WACM 2 would produce a Year Round tariff that would assume that there was little or no sharing. All generators within that zone would face the same Year Round charge per unit of capacity. In the view of the respondent, this would result in conventional generators within the zone paying the same charges as wind generators despite only producing output when the wind output was low. As a result, it was argued that this approach would produce a Year Round tariff that is not cost reflective for non-wind generation in the zone.

1.16. In a similar vein, the respondent noted that in its view constraint costs in ones with a lot of wind were more closely correlated with the outputs of wind generators than with higher load factor plants. It therefore argues, WACM 2 allocates overly high costs to high load factor generators and discriminates in favour of low load factor generators. For example, it suggests a nuclear generator operating at 90% would pay three times the charges under WACM 2 as a low load factor wind generator operating at 30%. They do not believe that this is reflective of the additional impact a nuclear generator has on constraints.

1.17. Some respondents also proposed the use of generic load factors in the charging calculation, similar to the level used by the SQSS scaling factors. This feature was not included in any of the options presented to us by the Workgroup and therefore we do not comment further on this.

Our views

1.18. The use of a generator's ALF as a proxy for the incremental cost of transmission network investment was at the heart of many of the CMP213 charging options presented to us, including WACM 2.   The use of ALF seeks to reflect that planning decisions are increasingly driven between a trade-off between investment to increase capacity and incurring constraint costs. This relationship is captured by transmission planners when they consider a CBA analysis.

1.19. In addition, WACM 2 recognises that capacity is less able to be efficiently shared in areas dominated by low carbon plant. This is because low carbon generators are more expensive to constrain off (due to interactions with government renewable energy support policies) and are more likely to generate at the same time. This results in higher constraint costs. It is therefore efficient to build more transmission capacity in these areas. In order to approximate this cost driver,

[12] C26 (Requirements of a connect and manage connection).

WACM 2 splits the Year Round tariff into a 'shared' and 'non-shared' element. Only the shared element is reduced by ALF. If the level of low carbon plant behind a boundary is 50% or less, then the entire Year Round tariff is considered 'shared'. Once this percentage exceeds 50%, an increasing proportion is considered 'non-shared'.

1.20. This approach is a simplification and we agree that in reality the relationship between generation output, plant mix and constraint costs is more complex. Transmission planners will consider many additional factors in a CBA such as levels of future demand. However, we note that significant consideration was given to this in the workgroups. This is discussed in detail in the FMR and we set out our views in our August 2013 consultation.

1.21. This simplification was deemed to provide a good objective approximation, under average circumstances, particularly when ALF is considered over the proposed 5 year time period. The evidence presented by the working group does show a broadly consistent, linear relationship across all zones. We note that at the extremes where either low carbon or carbon plant dominates behind a transmission boundary, the relationship may be less clearly linear. However, overall we consider this approach to be an appropriate proxy for the relationship between load factor and constraint costs and is an improvement to the currently methodology which does not recognise this relationship at all.

1.22. Our views in response to the other comments made by respondents are as follows:

- **ALF is "more cost reflective" than SQSS**: We do not agree with this interpretation. As noted above, ALF is used as a proxy for a generators impact on constraints and hence transmission investment. The use of load factor in the charging calculation provides a closer approximation to the investment cost drivers prescribed in the SQSS than the current method.
- **Potential beach of licence condition C26**: CMP213 does not propose any change to the way in which the balancing costs associated with managing constraints are recovered.

1.23. We note the views expressed that WACM 2 may result in perverse results in certain circumstances. The use of ALF is a proxy for the relationship between load factor and constraints. It therefore results in charges that are an approximation of the impact a generator has on transmission investment. WACM 2 may not precisely reflect an individual generator's impact on a specific constraint at a specific time. In addition, we note that the relationship may be less close at the extremes, for example in cases where there is 0% or 100% of a particular type of generation in a zone.

1.24. In the example referred to above of the nuclear generator, the respondent itself notes that it is appropriate that the tariffs for nuclear generators to be higher than those for wind. It just disputes this should be by a factor of three. However, as status quo would mean that both nuclear and wind were paying the same tariff, we consider that WACM 2 is the better methodology.

1.25. It would not be possible to develop a methodology that was able to capture every specific set of circumstances whilst being simple and transparent to operate in practice. We consider that WACM 2 results in an acceptable balance of cost reflective signals, transparency, stability and practicality.

Respondents' views: historical ALF is not forward looking

1.26. Some respondents were critical of approach to calculating the ALF using historical data. The substantive points raised include:

- It is inconsistent that a charging method that seeks to provide a forward looking signal is based on a generator's past performance.
- A generator should be able to respond to a charging signal by changing its load factor and see a change in the level of TNUoS charge payments (or receipts). The historical average approach to calculate ALF will dilute this ability to respond to an ex-ante charging signal.

Our views

1.27. The historical averaging approach developed by the CMP213 workgroup is an attempt to better reflect the different impacts (ie costs and benefits) of individual generators on the TOs' costs in an appropriate manner. The length of the historical average, five years with the highest and lowest values discarded, was a compromise solution to approximate this impact. We are mindful that a longer averaging period may provide a less representative charging signal of a generator's impact, but that a shorter averaging period may provide more volatile charges. NGET's view set out in the FMR, is that a period of 5 years provides a reasonable trade off that delivers a reasonable level of predictability, stability and cost reflectivity.

1.28. Our view is that the use of a generator's specific ALF, when averaged over 5 years, provides a reasonable mechanism for reflecting the impact that an individual generator has on investment decisions. We consider this to be an improvement to the existing approach which only recognises peak security as a driver of transmission investment and assumes that all types of generators contribute equally to it.

1.29. We acknowledge the views of some respondents who support an approach that uses forward looking annual forecast of load factor. They argue that this would provide a better indication of the impact of individual plant characteristics on future running costs. This would provide an incremental improvement in cost reflectivity relative to an historical approach. We consider that mitigation measures that are proposed within the load factor calculation (eg removing the highest and lowest values and for the load factor to be agreed with the relevant generator) provide an appropriate proxy for the incremental transmission costs triggered by a generator, and represent an improvement to the current method.

1.30. If we were to approve WACM 2, industry would be able to pursue further development of the load factor setting process through the normal governance process.

Respondents' views: ALF distorts generator dispatch

1.31. Some respondents commented that CMP213 options that use historical ALF will create a new variable cost of generation. This may increase or decrease generators' variable cost of generating and affect dispatch decisions[13]. One of these respondents went further to suggest that the impact could be significant and potentially distort trade with other EU member states.

Our views

1.32. We agree with respondents that the use historical ALF will have an impact on generator dispatch decisions. However, we consider this will be minimal.

1.33. The impact of WACM 2 on a generator's tariff will depend on a number of factors such as the type of generation and the mix of generation in a zone. Where a generator experiences an increase in tariffs, this will be an additional short run cost.

1.34. In theory, the change in relative costs for marginal generators could lead to higher cost generation running more often. However, we consider that the practical impact of this on the generation merit order and dispatch decision is limited. The highest or lowest load factor year in the five year period is discarded. Therefore, changes in load factor will not always have an impact on tariffs.

1.35. We instructed our consultants to perform further analysis in this area. The results are summarised below.

- The distortion would provide a signal for generators in the south to run more and those in the north to run less.
- As a consequence of more southern plant running, any generation cost increases due to distortion are likely to be outweighed by larger reductions in constraint costs and transmission losses.
- Baringa's analysis (on the Original Case) indicates that prices would decrease by an average of £0.05/MWh across the period of analysis.

[13] The NERA/ICL report considers the potential distortions to dispatch arising from a £1/kW Year Round Shared tariff for a generator under WACM 2. NERA/ICL concludes that there is an NPV saving of £10,965 in TNUoS for a 200 MW generator which reduces its generation by 100 GWh/year for two years. This is a reduction of 5p/MWh or an increase in SRMC of 0.1 % of a SRMC of around 50 £/MWh.

1.36. More detail on the analysis is included in Baringa's report published alongside this document. The conclusion of this work is that the impact on generator dispatch decisions would be minimal and, based on the modelling approach adopted by Baringa, potentially outweighed by movements in other parameters. We therefore disagree with the suggestion that the impact could be significant and potentially distort trade with other EU member states.

Respondents' views: other points raised on use of annual load factor

1.37. There were three other points raised in the responses include:

- the use of Final Physical Notifications[14] (FPNs) as the basis for load factor has flaws since there may be occasions when the FPN overstates the actual metered output.
- a charging methodology that uses only load factor will result in a significant burden being placed on all users through the residual charge to finance load related infrastructure in areas dominated by one plant type.
- the proposed method for calculating ALF could be made more responsive to factors which are outside the control of a generator's future running pattern.

Our views

1.38. Our response to the remaining points on the use of ALF is set out below.

- **FPN**: We recognise that a generator may be subject to Balancing Mechanism instructions from the System Operator[15]. This would potentially constrain the actual output of a generator at a particular location at a specific time meaning actual output was lower than the FPN. However, we consider that the use of FPN is a robust statement of the commercial intent by the generator and represents a suitable proxy reflecting the drivers of network investment.
- **Collection of revenue:** WACM 2 proposes to reflect the costs imposed by different types of generators on the electricity transmission network by splitting the tariff for use of the 'wider'[16] network into two components to align with the drivers of transmission investment. This will produce a Year Round tariff element that varies to reflect the costs imposed by users of the network driven by location and annual capacity reservation, used in the

[14] The Final Physical Notification for Balancing Mechanism Unit (BMU) is the level of import or export that a party expects to import or export from BMU in a settlement period.
[15] The Balancing Mechanism is used to balance supply and demand in each half hour trading period of every day. Where there is a discrepancy between the amount of electricity produced and that which will be in demand during a certain time period, the SO will accept a 'bid' or 'offer' to either increase or decrease generation (or consumption).
[16] The Main Interconnected Transmission System (MITS) is the boundary between the local transmission network (ie close to a generation site) and the integrated, or wider, electricity transmission network. The criteria for a MITS node are set out in 14.15.17 of the CUSC.

current method, but also the impact of an individual generator's load factor. While we acknowledge that a charging methodology that uses load factor in this manner may result in more revenue being recovered through the residual, we continue to believe that this approach is justified on the basis that it is a more appropriate guide to the incremental transmission costs triggered by a generator than the current method.

- **Load factor calculation:** We note that allowing generators to forecast their load factors in a 'hybrid' methodology is one way of providing further refinement to the historical methodology proposed for calculating ALF. Our views on the hybrid approach are set out in Chapter 6 of the August 2013 consultation. We continue to believe that such an approach would add additional complexity as it involves some ex-ante forecast and an ex-post reconciliation, and also require consequential changes to the billing systems to affect the submission and over-recovery payment. There is the option of future modifications of the load factor calculation through the normal governance process.

NGET's modelling presented in our impact assessment

Respondents' views

1.39. Those who were satisfied with the analysis of the impacts of the options presented in August 2013 expressed understanding of some of the difficulties faced in the modelling presented by NGET. In particular, they suggested that modelling can only be an approximate guide as to the impacts of implementing WACM 2 and that qualitative evidence is also important. They also stressed that in their view the results presented have been interpreted appropriately by Ofgem.

1.40. Those who were dissatisfied with the modelling had issues with the following areas:

- This approach contained a simplified assumption of how existing generators anticipated future capacity payments from the proposed capacity mechanism. Generators were closing because they were not anticipating these payments and this was increasing wholesale prices in the short run.
- Consumer bills are highly sensitive to modelled capacity margins through the interaction with the wholesale price. Some proposed that the modelling should be updated to more closely reflect the intent of DECC's proposed capacity mechanism to provide stable margins throughout the modelling period and improve the comparability of results between the charging options.
- Some argued that more sensitivity analysis should have been undertaken. For example, consumer bills could be sensitive to the modelled generation mix. Some questioned the extent to which consumer benefit was being driven by the assumed level of Carbon Capture and Storage (CCS) and little increase in onshore and offshore wind after 2020.

- It was argued by some that the interpretation of the analysis was flawed. For example, the total levels of renewable and low carbon generation developed under different options vary significantly.

Our views

1.41. NGET's modelling results were driven by assumptions that were made about the proposed capacity mechanism in advance of firm policy information. This approach contained a simplified assumption of how existing generators anticipated capacity payments prior to the introduction of the proposed capacity mechanism and factored these into decisions. This had an impact on wholesale electricity prices. Low margins increased wholesale costs leading to higher consumer bills.

1.42. The modelling approach was constructed to reflect an understanding of the UK government's EMR proposals as they stood at the time. Contract for Differences[17] (CfD) strike prices were also set to reflect the assumption that UK government policy targets are met.

1.43. The UK government has since provided further detail on the likely scope of the proposed capacity mechanism and published details of the applicable CfD strike prices. Furthermore, the EMR delivery plan has since confirmed that the published CfD prices will take into account the budget available (ie intention is to stay within the levy control budget framework).

1.44. We agree that the issues raised by respondents highlight weaknesses in the initial impact assessment modelling approach. We also decided there was merit in adjusting the modelling approach to reflect the most recent policy developments. We therefore commissioned Baringa to update the modelling approach. The updated modelling is presented in Baringa's report. This included four additional modelling sensitivities to address points raised by responses in this area.

1.45. We note the suggestion to perform sensitivity analysis on CfDs, for example replicating the published DECC strike prices. In the revised modelling the status quo and WACM 2 runs have different levels of CfD determined (endogenously) by the model to ensure that the 2020 policy target is hit. We consider this methodology is appropriate, given the competitive allocation of CfDs.

Alternative modelling of the impacts

1.46. One respondent criticised the rationale underpinning NGET's modelling approach. It commissioned NERA/ICL to conduct its own quantitative analysis and

[17] Under a CfD the purchaser agrees in advance to purchase a specified physical quantity of energy from the spot market at a "strike price". If the actual price paid by the purchaser is higher than the strike price, the counterparty to the contract (generator) pays the purchaser the difference in cost.

presented this in its consultation response. This analysis shows a £6.6bn consumer dis-benefit over the long term from implementing WACM 2 compared to the status quo. NERA/ICL also challenged the robustness of NGET's results.

1.47. The results of NERA/ICL's Original Case[18] and sensitivity[19] are set out below. There are set out in more detail in its report attached to RWE npower's consultation response published on our website.

Table 3: Summary of NERA/ICL's analysis

Costs relative to status quo 2014-2030 NPV £m		**NERA Original Total**	**NERA sensitivity Total**
Consumer bills	Power purchase	1,717	1,717
	Low carbon subsidy	2,851	269
	D-TNUoS	769	769
	Constraints	-63	-63
	Losses	687	687
	Total	**5,961**	**3,379**
Power sector costs	Generation costs	4,142	4,142
	Transmission investment	922	922
	Constraints	-63	-63
	Losses	687	687
	Carbon costs	n/a	n/a
	Total	**5,688**	**5,688**

Source: NERA/ICL

A positive number (black) represents a cost increase relative to the modelled version of status quo. A negative number (red) represents a cost decrease.

Our views

1.48. Since receiving the modelling results, we have discussed them with NERA/ICL (through a series of meetings and correspondence) to understand what is driving the difference in the modelling results. We have not been granted access to the model. Without having access to the model, we have had to limit our analysis to reviewing a description of the methodology, the modelling results, accompanying report and responses received to our questions. We have summarised the issues we have

[18] The analysis presented by NERA/ICL in the document entitled "Modelling the impact of WACM 2 Charging Model" (page ii), submitted on 9 October 2013, was updated by NERA/ICL on 25 November 2013 to correct an error identified in the CBA calculations. The effect of this error did effect the calculation of the NPV of the constraint payments. The corrected analysis is shown in Table 3.

[19] NERA/ICL's Original Case did not adjust the subsidy levels to reflect the increase in the wholesale price under WACM 2. If wholesale prices are higher, developers require less top up under the strike price. NERA/ICL provided a sensitivity analysis in December 2013 to show that if this effect is taken into account, the increase in low carbon subsidies under WACM 2 reduces to £269 m. This analysis is shown in Table 3.

identified with the model. These are also discussed in more detail in Baringa's report.

1.49. One area that we have focused on is the large increase in generation costs observed in the modelled version of WACM 2. We noted that both transmission costs and transmission losses increase. While the increase in transmission costs is expected (and consistent with our revised modelling) as generation shifts from sites in the South to Scotland as a result of lower TNUoS tariffs in these zones, we would have expected that the higher load factor of wind sites in these areas would reduce generation costs.

1.50. NERA/ICL explained that the major driver of generation costs is differences in the amount and location of onshore and offshore wind between the two options. We understand that more sites with lower load factors are developed. This increases the total amount of renewables development needed to achieve the UK government's 2020 target at lowest subsidy cost to consumers. Following discussions with NERA/ICL we understand that this explains nearly all of the £4.65 billion increase in power sector costs in its model. It also increases the amount of low carbon subsidy required to support renewable generators. This is the biggest driver of the difference in consumer benefit between Baringa's modelling results and those of NERA/ICL.

1.51. We questioned NERA/ICL on this issue in attempting to understand why lower load factor sites were being developed under WACM 2. Baringa has identified that under WACM 2 the lowest cost projects (Scottish highlands onshore wind with a load factor of ~50%) are not built in the NERA/ICL model. These have a levelised cost of £54.4/MWh under WACM 2, lower than the level of £56.3/MWh under status quo, and significantly lower than the next onshore or offshore project.

1.52. The explanation received from NERA/ICL was as follows:

"Such results may be down to:

- *Constraints on the rate of development for onshore and offshore wind;*
- *Constraints on the availability of particular onshore sites; and*
- *Trade-offs that exist between the model's ability to develop competing generation sites, created by the constraint that the model cannot build more capacity than required to meet the assumed renewables target (subject to a margin of modelling tolerance).*

Given the complexity of the model, it is not possible to observe precisely which of these effects is driving the result. Also, when interpreting the tables and charts showing levelised cost data, it is important to consider that they are simplified, static representations of the costs fed into the model (see above). In particular, the measure of TNUoS shown on the chart is averaged over a number of years, so the *data shown provide an approximate measure of the costs actually incurred by generators in our models."*[20]

1.53. In the absence of additional information we are unable to fully validate the reasons for NERA/ICL's modelling result. However, we do not consider that NERA/ICL have demonstrated that the renewable investment pattern observed is reasonable. We would expect a charging option that reduces TNUoS for onshore wind to lead to the cheapest projects to be developed, particularly under the current CfD arrangements through competitive auctioning for established technologies. NERA/ICL's suggestion that WACM 2 will increase generation costs, low carbon support costs and wholesale electricity prices to the extent indicated has in our view not been sufficiently explained. We do not understand the drivers of the NERA/ICL results which seem counterintuitive. We believe that overall the modelling approach developed by Baringa provides a better guide to the potential impacts.

Consistency, non-discrimination and complexity

Respondents' views

1.54. The charging arrangements currently apply equally to all existing and new generators, regardless of location or technology. The majority of respondents considered that WACM 2 tariffs are not discriminatory. However, some respondents did raise concerns in relation to consistency and differential treatment. The substantive points were:

- The categorisation of plant by "low carbon" and "carbon" characteristics may be discriminatory as it is an oversimplification[21].
- The current arrangements recognise that all generation users have access rights to transmission system based on capacity rather than output. WACM 2 introduces charges that mean users who are located in similar parts of the network but with a different mix of plant in a zone will face different TNUoS charges depending on the assumptions about their load factor. This could be discriminatory.
- The implementation of any option for change under CMP213 would lead to a more complex charging methodology than the current baseline.
- Our initial assessment failed to account for the distributional effects of the proposed change, particularly the risk that the change will add to perceptions of regulatory risk and increase costs to consumers through higher financing costs.

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[20] Reproduced with permission from the response submitted on 27 January 2014 to Ofgem by RWE npower on behalf of NERA/ICL.
[21] The respondent was of the opinion that it cannot be assumed that "low carbon" bid prices are always higher than those for carbon generators and will therefore trigger a higher level of transmission investment if there are higher concentrations of them in a zone.

1.55. In addition, some respondents raised concerns that WACM 2 was more complex than the status quo. This would deter competition.

Our views

1.56. We do not agree with the view that the CMP213 arrangements represent undue discrimination between participants in the market. The key issue is whether this differential charge treatment can be justified. We believe that aligning the transmission charging methodology to the SQSS provides objective justification charging users differently[22].

1.57. We recognise the increase in complexity associated with accommodating any of the CMP213 options. We consider the quality and transparency of supporting information to be crucial. We note NGET's work to provide clarity to the charges that generators will pay through provision of forecast tariffs (including the tariff calculator function) and supporting narrative.

1.58. It is our opinion that WACM 2 can increase effective competition since the benefits from the improvement to cost reflectivity reduce discrimination, do not adversely affect siting decisions and are not outweighed by the additional complexity of the TNUoS tariff calculation.

Treatment of HVDC and island links

1.59. Whilst AC circuits and cables of different voltage levels are included in the current TNUoS methodology, no HVDC technology, outside of the methodology for offshore generator connections[23], is currently taken account of.

1.60. WACM 2 includes 100% of the cost of HVDC converter stations[24] in the locational element of the generation tariff. Alternative options presented to us by industry socialised varying proportions of the cost of HVDC converter stations.

1.61. In our August 2013 consultation, we set out our views as to why we considered the treatment of HVDC converter stations under WACM2 to be the most cost reflective of the options presented to us.

1.62. Some respondents disagreed with our assessment and instead argued that we should have considered an option which socialised some proportion of the costs.

[22] We note that if the SQSS were to change then a change to the methodology and TNUoS charges would be expected to follow any changes to these deterministic methods (e.g. intermittent generation could be relied upon to contribute towards providing security at peak).
[23] 14.15.59 of Section 14 of the CUSC.
[24] When using HVDC cables converter stations are required to convert the AC power signal to DC and then back again to interface with the existing AC network.

There was not a consensus amongst these responses of the proportion of costs that should be socialised. These views are considered further below.

Equivalence of HVDC substations

1.63. Some respondents noted that the workgroup had provided evidence of the level of similarities between HVDC converter stations and other AC investments that were socialised in the current methodology. In their view, we had not explained how this had been taken into account when reaching our minded to position.

1.64. One respondent noted that if Ofgem did not think it was possible to agree a generic percentage for socialising HVDC converter station costs due to lack of evidence, it would still be preferable to choose the option that proposed considering the equivalence to AC investments on case by case basis.

Our views

1.65. Our view remains that it is appropriate that the costs that triggered by users should be paid for by those users. This promotes cost reflectivity and ensures efficient decisions. However, it may be appropriate to socialise some of the costs of HVDC converter stations if this would be consistent with the treatment of AC substations on the wider network.

1.66. The costs of HVDC converter stations are very high in comparison to an AC substation. The cost of the equivalent elements in an AC substation is likely to be much less than the cost of the relevant parts of an HVDC converter station. The evidence submitted to us does not include a comparison to the costs of an equivalent AC substation. However, we consider that this is likely to be below the percentage of costs to be socialised in the options presented to us.

1.67. It is also not clear to us whether quadrature boosters or voltage compensation equipment costs should be removed to reflect their equivalent functions to some AC substation components. In addition, we have no evidence of the extent to which the need for this functionality is driven by the introduction of HVDC circuits to the system and to which this functionality provides wider benefits to users other than those that are driving the reinforcement.

1.68. We note that one respondent to the consultation suggested that an AC line may have multiple substations. We understand the inference to be that we should consider the costs of one HVDC substation against multiple AC substations. We have not been presented with any evidence in support of this point and therefore do not currently have any basis for assessing equivalence on this basis.

1.69. Based on the evidence we have reviewed, we do not consider that the arguments discussed above are sufficient to support socialising the level of costs in the options presented to us by industry.

1.70. One respondent noted that our minded to position seems to be based on the view that HVDC converter stations for island links and HVDC bootstraps connecting two parts of the onshore network are equivalent to HVDC converter stations for offshore generators. While we note that our proposed method of including 100% of the costs of HVDC converter stations is consistent with the current methodology for the offshore transmission network, this is not the basis for our decision. In reaching our minded to position we considered the comparison between onshore HVDC converter stations and an onshore AC substation.

Potential wider benefits

1.71. A number of respondents to the consultation believed that there were wider benefits to the use of HVDC technology that meant that it was appropriate to socialise some of the HVDC converter substations. The benefits highlighted by respondents can be grouped into three categories:

- **Network benefits** – respondents highlight that there are wider system stability and control benefits through use of HVDC technology, especially newer voltage source converter (VSC) technology.
- **Socio-economic benefits** – some respondents noted that HVDC technology would be used to connect remote areas such as Scottish islands. This would bring about wider social and economic benefits and therefore the use of HVDC should be promoted through socialising some of the costs.
- **Strategic benefits to the HVDC industry** – in response to our consultation questions, some respondents said that they believed socialising an element of the HVDC substation costs would support learning and development in the HVDC industry. However, there was limited evidence put forward in support of this. Most respondents believed this would occur because socialising the costs would reduce a barrier to the deployment of this technology and that this would support the most efficient future development of the technology.

Our views

1.72. While there is some evidence that there may be wider system benefits related to HVDC technology deployment in GB, we have no evidence to quantify them. It is also unclear whether these benefits will accrue more widely to parties who would pay for any socialised element. In addition there may also be disbenefits associated with HVDC technology.

1.73. There may be wider socio-economic benefits to connecting remote areas such as Scottish Islands to the main transmission network. However, we do not consider this to be a relevant consideration for transmission charging. Moreover, our primary objective is to protect the interests of GB energy consumers. We consider that Government is best placed to set any policy based on wider socio-economic benefits.

1.74. Our August consultation invited respondents to submit evidence that socialisation of HVDC substations might deliver wider benefits in terms of technology learning and cost reductions. Respondents' views were mixed in this respect and did not receive any clear evidence to support a view that these benefits were material.

Summary of our views

1.75. Based on the limited information that has been presented, we remain of the view that it would not be in consumers' interests to socialise the costs of HVDC converter stations. We consider that the costs that are triggered by users should be paid for by those users.

1.76. We note the view expressed by some respondents of the potential for future developments in the treatment of HVDC converter station costs in the charging methodology. This would be based on evidence on the design and operation of HVDC links and island links as it emerges. We support this suggestion and expect NGET and industry to consider this issue at the appropriate time. This process of review and improvement should be facilitated through the normal governance process in a structured and transparent manner when new information is available.

Appendix 3 – Glossary

A

The Authority

Gas and Electricity Markets Authority (GEMA), established by section 1 of the Utilities Act 2000.

AC

Alternating current

C

CCGT

Combined Cycle Gas Turbine

CCS

Carbon Capture and Storage

CfD

Contract for Difference

Under a CfD the purchaser (typically an electricity retailer) agrees to purchase a specified physical quantity of energy from the spot market at a set price (the "strike price"). If the actual price paid in the spot market by the purchaser is higher than the strike price, the counterparty to the contract (typically an electricity generator or a financial institution) pays the purchaser the difference in cost. Conversely, if the price paid is lower than the strike price, the purchaser pays the counterparty the difference.

CMP

Connection and Use of System Code Modification Proposal

Connect and Manage

Under this regime generators can connect to the transmission network in advance of all the upgrades and reinforcements to the wider transmission system being put in place.

CUSC

Connection and Use of System Code

CSC

Current Source Converter

With CSC the direction of current cannot be varied, which means that reversal of the direction of power flow (where required) is achieved by reversing the polarity of DC voltage at both stations.

D

De-rated capacity margin

This is the capacity margin adjusted to take account of the availability of plant, specific to each type of generation technology. It reflects the probable proportion of a source of electricity which is likely to be technically available to generate (even though a company may choose not to utilise this capacity for commercial reasons).

E

Electricity transmission system
The system of high voltage electric lines providing for the bulk transfer of electricity across GB.

F

FPN
Final Physical Notification
The FPN for a Balancing Mechanism Unit is the level of import or export that a party expects to import or export in a settlement period.

I

Interconnector
Equipment used to link electricity systems, in particular between two EU Member States.

M

MITS
Main Integrated Transmission System. A MITS node is defined as being a node with more than four transmission circuits, or two or more transmission circuit and a Grid Supply Point.

N

National Grid Electricity Transmission plc (NGET)
The electricity transmission licensee in England & Wales

P

Plant margin
This is the amount by which the installed generation capacity exceeds the peak demand, eg peak demand of 100MW and 120MW of installed generation has a 20MW plant margin (20%).

R

RIIO-Transmission Price Control Review 1 (RIIO-T1)
The current price control of the electricity and gas transmission network operators, following the TPCR4 rollover. This price control runs from 1 April 2013 to 31 March 2021 and is the first transmission price control review to reflect the new regulatory framework, RIIO (Revenues = Incentives + Innovation + Outputs), resulting from the RPI-X@20 review

S

SQSS
System Security and Quality of Supply Standards

T

TEC
Transmission Entry Capacity

TNUoS
Transmission Network Use of System (charge)

Transmission Owner (TO)
Transmission Owner is used to describe the onshore transmission companies, NGET, Scottish Power Transmission and Scottish Hydro Electric Transmission. The use of the term TO in this document only describes the transmission ownership function; NGET also has a system operator function

V

VSC
Voltage Source Converter. VSC maintain a constant polarity of DC voltage and power reversal is achieved instead by reversing the direction of current. The additional controllability of VSC (at either end) improves the harmonic performance and does not rely on local voltage sources in the AC system for its operation.

W

WACMs
Workgroup Alternative CUSC Modifications

Appendix 4 – Feedback questionnaire

Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

Please send your comments to:

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