Making a positive difference for energy consumers

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

Decision

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Overview:

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

Project TransmiT identified defects in the current transmission charging methodology. An industry-led process was established to address the defects which led to several options for change being identified and a subset of these options being recommended to us by an industry panel. In August 2013 we published a consultation and analysis of the impacts of these options, including our initial minded-to position. We published a further consultation in April 2014 on new evidence that came forward in response to that consultation.

Following careful consideration of the evidence, including all the consultation responses, we find that our minded-to option set out in August 2013 and April 2014 is more cost reflective than the current methodology and best meets our statutory duties. We have therefore decided to approve this option for implementation in April 2016. We announced our decision on 11 July 2014 and this document sets out our reasoning.

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Context

Great Britain's energy sector is facing an unprecedented challenge. There is 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/

Project Transmit: Further consultation, April 2014
https://www.ofgem.gov.uk/publications-and-updates/project-transmit-further-consultation-proposals-change-electricity-transmission-charging-methodology

Project Transmit: announcement of decision July 2014
https://www.ofgem.gov.uk/press-releases/ofgem-gives-green-light-new-%C2%A31.2-billion-scottish-subsea-link-and-transmission-charging-reform

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Executive Summary

Connection and Use of System Code (CUSC) Modification 213 (CMP213) is a modification to the electricity transmission charging arrangements. It arose out of a Significant Code Review in 2011 and addresses defects that had been identified in the Transmission Network Use of System (TNUoS) charging methodology. Of the options for change presented to us by industry, we have decided to approve the option known as WACM 2. We have decided that National Grid should implement this in April 2016. In reaching our decision we have considered the information provided in the Final Modification Report from the CMP213 working group and the responses to our two consultations on the options. Our assessment is that WACM 2 better meets the relevant CUSC objectives and better meets our wider duties and principal objective than the status quo or any of the other modification proposals presented to us for approval under CMP213. The reasons for this are summarised below.

The change under WACM 2

WACM 2 would split the TNUoS tariff for generators into two parts: the Peak Security tariff and the Year Round tariff. Only conventional generators would be charged the former but all generators, including intermittent ones, would be subject to the latter. This aligns to the transmission planning standard and reflects the fact that intermittent generators are not assumed to contribute to meeting peak security. In its power flow model used to calculate tariffs, National Grid would split the circuits between the two tariffs using similar assumptions to those in the transmission planning standard.

There would also be two further adjustments to the Year Round tariff. The first of these is to split the tariff into two elements: 'shared' and 'non-shared.' This refers to generators' ability to 'share' transmission capacity which depends on the concentration of types of generators in a particular area. It recognises that it is efficient to build more transmission capacity for areas with a high concentration of low carbon generation because this type of plant is likely to be generating at the same time (ie when the wind blows) and is expensive to constrain off. Once the proportion of a low carbon generation in an area exceeds 50%, then part of the Year Round tariff will be classed as 'non-shared'. The proportion of the Year Round tariff that is non-shared will increase as the percentage of low carbon generation increases.

The second adjustment is to adjust the 'shared' element of the Year Round tariff by a generator's average annual load factor for the last five years (with the highest and lowest years discarded). This recognises that there is a link between the level of constraint costs triggered by a generator and the level of transmission investment.

Our assessment

WACM 2 is a better proxy of the drivers of transmission investment than the status quo, or other options presented, because it is more closely aligned to the transmission investment decision making criteria. Tariffs are therefore more cost reflective and better reflect the impact a generator has on the transmission system than the status quo. We recognise that in reality the impact of individual generators may differ from that estimated by WACM 2. However, this is a feature of the investment cost related pricing methodology. This brings other benefits for example through smoothing the lumpy nature of transmission investment and making tariffs more stable and transparent. These are important aspects to reducing barriers to entry and facilitating effective competition.

Our view is that there is an appropriate balance in WACM 2 of accuracy and transparency. There may be circumstances where WACM 2 could be less cost-reflective than the status quo, where for example, an intermittent generator triggers an investment with a very high cost such as an High Voltage Direct Current (HVDC) link. We consider the evidence shows that such divergences are likely to be limited and unlikely to lead to substantial distortions when set against the wide range of circumstances in which WACM 2 is more cost reflective. Therefore, we consider WACM 2 to be more cost reflective for GB as a whole. As a result, generators will be able to make more efficient decisions taking into account their impact on the transmission system, which in the long run will benefit consumers by lowering bills.

WACM 2 also incorporates solutions for HVDC into the charging methodology. In doing so, it does not socialise any of the associated converter station costs. We have not seen strong enough evidence to avoid targeting the recovery of these costs from the users of the links.

Our assessment is therefore that WACM 2 better meets the CUSC objectives than other options presented including the status quo as it is more cost-reflective, better facilitates competition and reflects developments in the transmission owners' businesses.

We also consider that WACM 2 better meets our wider duties and principle objective to protect the interests of existing and future consumers than the status quo and other options presented. We have considered a range of evidence in reaching this decision, not just the modelling carried out as part of the impact assessment. This is because modelling the impact on consumer bills does not show the full impact on consumers. The complexity of the energy market makes modelling very difficult and the results are sensitive to small changes in assumptions. Overall, we think there are benefits, not captured in the modelling, which will result in long-term benefits to consumers. There are more complex effects on generator behaviour which cannot be fully taken into account in a static model, such as how generators would respond to the higher profits under WACM 2. In a competitive market, we would expect these profits to be eroded through competition and that benefit transferred to consumers. In addition, there are wider sustainability benefits for consumers which cannot be captured in a model such as increasing the likelihood of meeting current and future renewables targets for fixed levels of budget.

It is important to allow generators to respond to any significant changes in the charging methodology within the notice period required by the user commitment arrangements. We have therefore decided to implement from 1 April 2016, the first date generators can adjust their agreed levels of capacity without incurring penalties.

1. Background

Chapter Summary
Background to CMP213 and the main changes to the charging methodology under WACM 2

1.1. Electricity generators and suppliers pay charges for using the electricity transmission network. These are known as Transmission Network Use of System (TNUoS) charges. They are determined using a methodology administered by National Grid Electricity Transmission plc (NGET). CMP213 is a modification to this methodology developed through the industry-led Connection and Use of System Code (CUSC) modification process. It is the culmination of a review of transmission charging known as Project TransmiT. A short outline of the development of Project Transmit is included in Appendix 1.

1.2. We have consulted twice on the CMP213 proposals that were put to us by industry to address the defects in the existing methodology identified as part of our Significant Code Review (SCR) in May 2012. This document explains our final decision and our reasons for it.

Reasons for the Significant Code Review

1.3. TNUoS charges recover the costs of installation, reinforcement, maintenance and renewal of assets by the owners of the transmission network that facilitate access to and the flow of power across the network. These costs vary both by location of the user and how and when they use the network.

1.4. 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 enable 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 lowest cost to the consumer.

1.5. Through the SCR process, a number of defects were identified in the existing transmission charging methodology in consultation with industry. Charges were considered to not reflect the costs different generators impose on the system especially that intermittent generators generally have a lower impact on transmission investment than conventional generators. As increasing numbers of intermittent generators connect to the system, it was considered that this could have a detrimental impact on the ability to achieve the UK government’s Renewable Energy

Strategy of 30% of generation from renewable sources by 2020 and on the overall cost of the system as a whole, including consumer bills[1].

1.6. We therefore directed NGET[2] to raise a modification to better reflect the following in the transmission charging methodology:

- the costs imposed by different types of generators,
- the development of High Voltage Direct Current (HVDC) links that will run parallel to the onshore network. The methodology needs updating as the first HVDC link is due to be commissioned in 2016.
- the potential development of subsea cable transmission links to islands.

Modification Process

1.7. In response to the SCR, industry developed different solutions to address these defects in a CUSC working group[3]. There were 27 options presented to the CUSC panel and a majority voted that eight of these better facilitated the CUSC objectives[4] than the status quo. Ofgem received the Final Modification Report (FMR) for CMP213 on 14 June 2013.

1.8. Having considered this, we issued an impact assessment and consultation on our minded-to position in August 2013. We said we were minded to accept the option known as "WACM 2", subject to the responses to the consultation. We said why we considered this option better addressed the defects and furthered the relevant objectives and our statutory duties compared with the status quo and the other options presented. There were several responses to this consultation, including some material new evidence that had not previously been presented. As a result, we told industry in December 2013 we needed more time to give it full consideration. We explained our view of this new evidence in our further consultation in April 2014 and that we remained minded to approve WACM 2 while seeking industry views on the new analysis.

1.9. The further consultation closed on 27 May 2014. We received 17 responses. These are published on our website. We have considered these responses, along with the responses to our earlier consultation and the evidence presented in the FMR in reaching our decision.

[1] These, along with the quality and security of supply across GB were the three broad aims of Project TransmiT.
[2] Standard Licence Condition C10 of NGET's Electricity Transmission Licence provides for NGET to raise a modification resulting from a SCR when directed to by the Authority
[3] The workgroup comprised of a number of industry specialists from a broad range of users
[4] The CUSC objectives are set out in in Chapter 2

Proposed modification

1.10. TNUoS charges are calculated using an investment cost related pricing (ICRP) methodology. Generators face a local tariff and a wider tariff – the former relates to their impact on parts of the system close to a generation site, and the latter relates to their impact on the wider transmission system. The changes under consideration relate only to the wider tariff[5], which has two parts. The first is a cost reflective locational element, designed to reflect the impact a generator has on the costs of the transmission network. This is calculated by assessing the impact on the costs of the network of adding a megawatt (MW) of generation or demand at different locations on the system. The resulting impact is converted into a monetary value in the tariff by using the average cost of building the existing network circuits at current costs.

1.11. The second component of the tariff recovers the costs not captured by the locational element. This is known as the residual and does not vary by the users' location.

1.12. Tariffs are averaged into zones and currently generators are charged based on their Transmission Entry Capacity (TEC)[6]. All generators in a zone face the same tariff on a £/kW basis.

1.13. Under WACM 2, the key principles of the ICRP methodology would still apply. However, it would change the locational element of the wider tariff for generators with the result that different types of generators would face different tariffs within a zone. This would reflect the impact different types of generators have on the system. The key changes are described below with detail of how these address the defects identified through the SCR set out in the next chapter.

Description of changes under WACM 2

1.14. WACM 2 splits the locational tariff into two elements. The 'Peak Security' tariff and the 'Year Round' tariff. Intermittent plant would not pay the Peak Security tariff. All generators will be charged the Year Round tariff, multiplied by their average annual load factor for the last five years (ALF) for the proportion that is 'shared' (see below). The change reflects how different plant drives different levels of investment and recognises that intermittent generation does not impact on investment in capacity for peak demand.

1.15. The Year Round tariff would be further adjusted into a 'shared' and 'non-shared' element. The split is based on the proportion of low carbon generation in an area. If the level of low carbon plant behind a boundary is 50% or less, then the

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[5] The methodology for demand tariffs and for local tariffs for generators does not change as a result of WACM 2.
[6] TEC is the maximum amount of electricity a generator is allowed to export on to the transmission system.

entire Year Round tariff is shared. Once this percentage exceeds 50%, an increasing proportion is considered ‘non-shared’. This change is to reflect that plant in zones dominated by low carbon plant tend to drive higher levels of constraint costs[7] and therefore investment than if there is a range of plant in a zone.

1.16. The locational element of the wider tariff for generators under WACM 2 will be calculated as follows:

Component of locational tariff	Conventional generators	Intermittent generators
Peak Security Tariff	£/kW x TEC +	
Year Round Tariff – non shared	£/kW x TEC +	£/kw x TEC +
Year Round Tariff - shared	£/kW x TEC x ALF	£/kw x TEC x ALF

1.17. WACM 2 will also incorporate a methodology for the treatment of HVDC circuits into the charging model. It will set the cost for these circuits to be used in calculating the locational tariff. This will include 100% of the cost of the HVDC converter stations. This will also apply to HVDC connections to islands.

Other options considered

1.18. In August 2013 we said that of the options presented to us, we were minded to accept WACM 2. The other options varied from WACM 2 in the following ways and each option was a combination of these variations:

- The way the charging methodology captured the impact of low carbon generation in an area on transmission investment. There were two alternative options presented in addition to that included in WACM 2, along with an option that did not include any adjustment for this effect.
- The assumptions used to calculate ALF. There was an alternative option in which generators could have chosen to use a forecast of their load factor rather than their 5 year historic average.
- The percentage of HVDC converter stations to be removed from the locational element of the tariff. There were three alternative options: remove 60% of the costs from locational element, remove 50% or remove a percentage specific to each project.

[7] Constraint costs are the payments made to generation parties by the System Operator to manage congestion on the system where there is insufficient network capacity.

1.19. There was also an option presented that would have resulted in radial transmission circuits no longer being included in the wider tariff[8]. Instead, these links would form part of the 'local' transmission network for the purposes of TNUoS charges.

1.20. In our August 2013 consultation, we said that the combination of variables in WACM 2 best met the defects identified in the SCR, and the relevant CUSC objectives, and was most consistent with our principal objective. Full details of all the options considered and our reasoning are included in the FMR and our August 2013 impact assessment. This decision document therefore only considers our decision between the status quo and WACM 2.

[8] Radial circuits are single 'spurs' that link generation and/or demand in one location to the wider interconnected transmission network.

2. Decision

Chapter Summary
Here we explain our decision and the reasons for it.

2.1. We have decided that WACM 2 better facilitates the relevant CUSC objectives than the status quo and the other options presented to us. It is most consistent with our principal objective and wider duties to protect consumers.

2.2. In reaching this decision we have considered the evidence presented in the CUSC Panel Final Modification Report (FMR), the responses to our initial August 2013 impact assessment and consultation and the responses to our further consultation in April 2014. This chapter discusses the reasons for our decision against each CUSC objective and our principal objective.

Cost reflectivity

2.3. Standard condition C5 of National Grid's electricity transmission licence sets out the objectives we must assess our decision against. This first objective states that transmissions charges should:

> "reflect, as far as is reasonably practicable, the costs…..incurred by transmission licensees in their transmission businesses…"

2.4. Cost-reflective charges are important as they allow market participants to make efficient investment decisions taking into account the impact that they have on the transmission network. This helps develop an economically efficient transmission system.

2.5. Our decision is that this objective is better met by WACM 2 because it better reflects the impacts different users have on the costs incurred by the owners of the transmission network. This is because it is a closer approximation of the transmission investment decision-making process. Our reasons for reaching this decision are explained below, taking into account responses to both our consultations.

Transmission investment decision process

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

2.7. The growth in intermittent generation connecting to the transmission system has changed the nature of investment planning. Traditionally, this has been driven by the need to ensure peak security in an environment dominated by conventional generators. However, intermittent generators cannot be relied upon to be operating at peak demand. In addition, increasing intermittent generation has given rise to investment planning now being driven to efficiently managing constraint costs. The SQSS was updated to reflect this shift in 2011 to include two sets of criteria setting out the assumptions to be used when assessing the required level of capacity[9]. TOs must build transmission capacity determined by the following two conditions:

- Demand Security criterion – the minimum transmission capacity required to ensure that conventional generators can meet demand at times when intermittent generators cannot run (ie there is no wind).
- Economy criterion – the additional transmission capacity needed above that to meet peak demand to efficiently manage the system taking into account the need to manage constraint costs in an effective and economic manner.

2.8. As well as these two criteria, the SQSS also recognises that in reality, a full cost benefit analysis (CBA) will be required as part of the decision-making process for major investments. This may drive a different level of investment from that resulting from either of the two criteria above.

2.9. Currently there is a mismatch between the investment planning requirements which drive actual transmission investment costs and the charging methodology which only considers peak demand as the driver of investment costs. WACM 2 seeks to address this defect and more closely align charges for generators to the costs they impose on the system. It updates the charging methodology by splitting the locational tariff into two components:

- Peak Security tariff – only conventional generators will be charged this component. This is because, under the SQSS Demand Security criteria, it is assumed that intermittent generators do not contribute to peak security and therefore do not drive investment for this reason.
- Year Round tariff – all generators will receive the year round tariff adjusted for their output. This is designed as a proxy for the impact a generator has on investment to manage constraint costs in an economic way. The reasoning for the use of annual load factor (ALF) [10] in this calculation is discussed in the next section.

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[9] https://www.ofgem.gov.uk/publications-and-updates/decision-proposal-amend-minimum-transmission-capacity-requirements-system-security-and-quality-supply-standard-sqss-gsr009

[10] ALF is a generator's actual annual output expressed as a percentage of its maximum annual

2.10. To determine how generators in different areas impact on investment in that area, NGET must determine which requirements would drive investment under the SQSS. They will do this by allocating the transmission circuit routes in the power flow model used to calculate the tariffs to either the Peak tariff or the Year Round tariff. This is based on which drives the maximum flows on that circuit using assumptions that are consistent with the two criteria in the SQSS.

2.11. We therefore consider that, in principle, splitting the tariff into two components more closely aligns the charging methodology to the investment decision making process than the status quo. It is therefore more cost reflective. Our view is that the way NGET determine the allocation of circuits to each tariff is appropriate. It reflects that, under the SQSS, intermittent plant do not drive investment for the purposes of peak security. It also recognises that managing constraints efficiently is becoming increasingly important in driving transmission investment. This is an improvement on the existing methodology which only considers one driver of investment with all plant contributing equally to this.

Use of annual load factor

2.12. Different types of plant impact differently on the transmission system. A further adjustment is therefore made to the Year Round tariff for a generator’s ALF and to account for how the mix of generation in an area affects transmission investment.

2.13. Under status quo, the charges paid by generators vary only by their Transmission Entry Capacity (TEC), the maximum amount of capacity they can use on the transmission system. But when transmission investment planners carry out a full CBA to determine the efficient level of investment, they will consider how a generator impacts on constraint costs on the system. This will be based on a generator’s output rather than its capacity. To reflect this, another adjustment is made in WACM 2 to adjust the Year Round tariff by a generator’s ALF. This is a proxy of the impact an individual generator has on the costs of a system when investment is planned to manage constraint costs. Plant that operates more frequently would pay charges reflecting their increased likelihood of triggering (or avoiding) constraint costs.

2.14. The existence of empirical evidence of a link between output and constraint costs was the subject of much debate during the CUSC workgroup and respondents to both consultations have continued to present arguments on the matter. We reviewed NGET’s analysis presented in the FMR which plotted the relationship between constraint costs and outputs based on market modelling using the Electricity Scenario Illustrator (ELSI) model. From this, the majority of the workgroup

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output. The calculation of ALF in WACM2 uses the average of the last five years annual load factor with the highest and lowest years discarded.

considered that a change to the charging methodology based on a linear relationship between a generator's annual load factor and its impact on incremental constraint costs was better than the status quo. However, it was noted in the FMR that this relationship varied across different plant types and location.

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

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

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

2.18. The calculation of WACM 2 will use a specific load factor for each generator using its output from the previous five years, with the highest and lowest year discarded. Some members of the working group and respondents to our consultation said it is not appropriate to use historic data to produce a forward-looking charge. In addition, some said it will distort output decisions as generators' TNUoS charges will vary as output varies. Our view is that using historic load factors is a transparent way to estimate the impact that a user has on the system. Forward-looking load factors would be subjective and less transparent. As we stated in our April 2014 consultation, an assessment of dispatch distortion carried out by our consultants, Baringa, showed that any impact of this would be minimal.

Comparison of tariffs to long run marginal cost (LRMC)

2.19. Based on an assessment of the principles that drive transmission investment and associated supporting evidence presented during the workgroup process, we consider that WACM 2 better reflects the drivers of transmission investment and so is more cost reflective. Therefore, in principle, as a result of implementing WACM 2 and correcting the identified distortion in the existing methodology, market participants will be able to make more efficient commercial decisions about where to locate new generation and when to close existing generation, taking into account the wider costs of these decisions on the network. This facilitates the development of the GB electricity sector and will, in the long run, benefit consumers in the form of lower bills.

2.20. During the consultation process RWE nPower (RWE) presented evidence which compared the status quo and WACM 2 tariffs to a view of the long run marginal cost (LRMC) of the transmission system based on modelling carried out by NERA/ICL. This was proposed as a way to quantitatively assess which set of tariffs were most cost reflective (ie closest to LRMC). RWE state that we cannot determine that WACM 2 is more cost reflective than the status quo without having carried out this assessment.

2.21. The modelling showed that in the majority of cases that WACM 2 was as good as or better than the status quo as compared to NERA/ICL's view of LRMC. This was based on a set of subjective assumptions about, for example, future generation and type of investment required on the system. The only circumstance in which NERA/ICL showed that WACM 2 was consistently less cost reflective than the status quo was for intermittent generators in Scotland after the construction of the Western HVDC link. We discussed this in our April 2014 consultation. In particular, we said that as NERA/ICL made the assumption that the marginal investment required to facilitate flows of power from Scotland to England will always be an HVDC link or an investment of equivalent cost, our view was that this effect was overstated. We asked for industry's views on our assessment.

2.22. We have reviewed the responses to the April 2014 consultation and we remain of this view. Evidence shows that there will be a range of investment in Scotland over the long term and some respondents to the consultation provided additional evidence in support of this position. Our view is:

- There may be additional HVDC links in the medium term but these will be considered on a case by case basis under the Strategic Wider Works process. Ofgem's approval of the funding for the Western HVDC link has not set a precedent that other HVDC links are the only future option to reinforce the network in Scotland.

- There will also be other investments in this area in the short to medium term and this is supported by National Grid's Electricity Ten Year Statement. This shows the range of transmission investment being considered including smaller scale upgrade works to lines or substations. As a result, we do not consider that all this investment will be at a cost greater than the average cost of the existing network used in the ICRP approach.

- The Baringa's impact assessment modelling also supports this view. For example, it shows only one further HVDC link built to facilitate the flow of power from Scotland to the South (Eastern HVDC) in the Original Case. This is built in 2021 under both the status quo and WACM 2. That only one Eastern HVDC link is built (rather than a possible three links in this area) is supported by discussions at the Electricity Network Strategy Group[11] where the TOs have set out their considerations for smaller onshore reinforcements to more efficiently manage congestion on the network, reducing the need for more HVDC links.

2.23. We therefore consider that the risk of a long run divergence between WACM 2 tariffs and LRMC in Scotland is not materially greater than in the status quo methodology. We are of the view that any short-term divergence will not have a material impact on the overall outcomes of the system and will not outweigh the benefits of a more cost reflective system for GB as whole. RWE state that in its view, wind generators are more sensitive to locational signals than other plant and so any divergence between tariffs and LRMC for these generators will have a disproportionate impact on the effectiveness of the system. We do not share this view. We consider that a range of different types of plant can respond to the locational signals provided by TNUoS charges. This is supported by the effect WACM 2 has on decisions by all plant in the Baringa modelling. We also note that, based on the Baringa modelling, WACM 2 does not have a significant effect on the building of new HVDC links – the only difference in HVDC build between the status quo and WACM 2 is that the Eastern HVDC link is built one year earlier under WACM 2 in the Alternative Case. We do not therefore consider that there is evidence that WACM 2 is driving inefficient levels of investment which would result in transmission costs exceeding the benefits of more efficient generation resulting from more development of higher yield renewable sites in the North.

2.24. The quantitative analysis carried out by NERA/ICL is based on subjective assumptions. Its calculation of LRMC is based on the modelling methodology and assumptions it has chosen. One respondent to our further consultation provided details of its own concerns about the assumptions used by NERA/ICL supporting this view. The modelling of consumer benefit (discussed later in this section) also demonstrates how small changes in assumptions can have a big impact on results. Our view is that WACM 2 better reflects the investment decision making process and therefore better reflects the impact a generator has on the system. WACM 2 is a proxy of the impact a generator has on the system and will not exactly match the actual impact in every case. NERA/ICL have identified a case where tariffs are not an exact match due to the nature of the ICRP methodology. We agree that this may arise but we do not consider that it is as likely as NERA/ICL have assumed, and will not have a material impact on the system. Doing our own analysis of LRMC, which

[11] https://www.gov.uk/government/groups/electricity-networks-strategy-group

would be based on our own subjective assumptions, is unlikely to inform this view further.

HVDC methodology and island links

2.25. While Alternating Current (AC) circuits and cables of different voltage levels are included in the current TNUoS methodology, no subsea HVDC technology is currently taken account of (outside of the methodology for offshore generator connections). Similarly, there is no provision for island links of either AC or HVDC technology. These have been incorporated into the methodology under WACM 2.

2.26. The options presented to us in the FMR varied in the proportion of HVDC converter station costs that are included in the calculation of the locational tariff. Under WACM 2, 100% of these costs would be incorporated into the locational tariff. We have considered whether this is cost reflective and consistent with the existing ICRP methodology where the costs of AC substations are socialised. We set out our analysis in the August 2013 impact assessment consultation and provided further analysis in light of responses in Appendix 2 to our April 2014 consultation.

2.27. Our view is that locational tariffs should reflect the differences in the costs of providing transmission capacity in different areas of the country. Our starting point is therefore that the benefits of a cost-reflective charging methodology will be best realised if the cost of HVDC cables, including converter stations are reflected in the tariffs of the generators who use those circuits unless there is evidence as to why socialising some of these costs would be more appropriate.

2.28. We have considered whether there are wider benefits to users of the transmission system from having HVDC technology, such as system stability, which would mean that it would be appropriate for some or all of the cost of HVDC converter stations to be recovered from all users. We are not persuaded by the evidence that these benefits are sufficiently material to outweigh the principle of cost reflectivity.

2.29. We have also considered whether the treatment of HVDC converter stations under WACM 2 would be discriminatory because it is not consistent with the existing onshore methodology, which includes AC substations in the residual element of the charge. We note that WACM2 would be consistent with the offshore transmission charging approach.

2.30. During the workgroup process and subsequent consultation, we were presented with some suggested percentages of the cost of HVDC converter stations that could be removed from the locational charge. These were based on an assessment of the percentage of the elements in an HVDC converter station that had an equivalent function to those in an AC substation. However, we did not receive enough evidence to enable us to properly assess whether the percentages proposed appropriately reflected the costs of equivalent components between the two types of asset. In the absence of this evidence, not removing any element of the HVDC converter station is our preferred option.

Conclusions

2.31. WACM 2 is an improvement to the existing transmission charging methodology and corrects the defect identified in the significant code review. It is a better proxy for the drivers of transmission investment across GB as a whole and therefore in our view result in tariffs that more closely reflect the impact a generator has on the transmission system in the long run. It sets an appropriate balance between accuracy and transparency of tariffs.

2.32. Overall, are satisfied that implementing WACM2, a methodology that is more cost-reflective, will allow market participants in GB to make more efficient decisions. We expect to see the benefits of this through more efficient renewable sites being developed, now that the defect in the transmission charging methodology has been corrected. This fulfils the original objectives of Project TransmiT, better meets the relevant CUSC objectives and furthers our principle objective.

Competition

2.33. The second relevant CUSC objective we must consider is whether WACM 2 would result in a more competitive energy market. Standard condition C5 of National Grid's transmission licence states that transmissions charges should facilitate:

> "effective competition in the generation and supply of electricity and (so far as is consistent therewith)...competition in the sale, distribution and purchase of electricity"

2.34. We have decided that this objective is better met by WACM 2.

2.35. Currently, some generators, especially intermittent generators, may be receiving tariffs that overstate their impact on the network creating a barrier to entry. WACM 2 more accurately targets the different costs that generators impose on the transmission network at different locations. This should reduce the barrier to entry.

2.36. In addition, our view is that the current methodology could be discriminatory. Discrimination can inhibit competition and can arise not just from treating like cases differently without objective justification, but also from unjustifiably treating different cases alike. Currently, all generators receive the same tariff in a zone but this does not reflect how different generators may drive transmission investment in that location according to the investment planning process. WACM 2 would reduce this discrimination as different generators would be treated differently according to the impact they have on the network. This is an objective justification to charging users differently and is therefore not in itself discriminatory, as suggested by some respondents to our consultation.

2.37. Reducing a barrier to entry and reducing discrimination should facilitate competition as generators should be able to more easily compete on their relative merits ie underlying cost differences and efficiencies. In our view, this is not outweighed by the increased complexity of the methodology. In addition, while there is an increase in the volatility of tariffs under WACM 2 due to the increase in the number of components to the calculation, we do not consider this will affect competition significantly.

2.38. The effect of implementing WACM 2 will in most cases be to increase the annual tariffs for generators in the South and decrease tariffs for generators in the North on an ongoing basis. Some respondents have argued that the negative impact on generators in the South outweighs the potential benefits from greater cost reflectivity. We note that the impact assessment presented in August 2013 showed some distributional effects with resulting decreases in profits for generators in the South and increases in profits for generators in the North over the modelling period. This effect arose primarily due to the decreases in wholesale prices from implementing WACM 2 alongside higher TNUoS charges for southern plant. The updated Baringa modelling presented with the April 2014 consultation showed a different effect on generators due to the interaction with the Capacity Mechanism[12]. The implication of the revised modelling is that generators are compensated for higher TNUoS charges through higher capacity payments. This dampens the distributional effects of implementing WACM 2. We are therefore of the view that these effects do not outweigh the benefits from a more cost reflective charging methodology as a whole.

Taking account of developments

2.39. The third CUSC objective we must consider is whether WACM 2 properly takes into account developments in the transmission licensees' transmission businesses.

2.40. We have decided that this objective is better met by WACM 2. Our view is that the transition to a low carbon economy is driving changes to the generation mix. This has required the building of the Western HVDC bootstrap as well as giving rise to the potential for some further investment in HVDC as well as links to islands to connect renewable generation. This was not envisaged when the charging methodology was developed. WACM 2 takes this into account and is therefore an improvement on the status quo.

European considerations

2.41. The last CUSC objective we must consider is whether WACM 2 complies with the Electricity Regulation and binding EU decisions. Our decision is that approving WACM 2 is consistent with this objective.

[12] The Capacity Market is part of the Governments Electricity Market Reform proposals. The aim is to ensure that there is sufficient electricity generation capacity to meet to demand at all times. Generators will receive a capacity payment in return for being available to generate when required.

2.42. Some respondents said that the use of ALF, a factor which varies with output, is contrary to the European position on transmission charges for generators and could distort European trade. However, this approach is consistent with the recent Agency for the Cooperation of Energy Regulators (ACER) opinion[13] on levels of transmission charges for generation. This says that 'lump sum' charges, including charges set out at the beginning of the year and based on historic levels of outputs, do not tend to have an impact on operational decisions. This is consistent with the Baringa analysis carried out at UK level.

Authority's principal objective

2.43. The Authority's principal objective is to further the interests of existing and future consumers.

2.44. Our decision is that this objective is better met by WACM 2. In reaching this decision, we considered the updated impact assessment modelling carried out by Baringa, an assessment of other impacts that have not been modelled and responses to our April 2014 consultation.

2.45. In our April 2014 consultation, we set out our reasons for considering a broad range of evidence when assessing the impact of WACM 2 against our principle objective. We noted that the impact assessment showed a potential impact on consumers ranging from £0.05 - £0.75 average increase in bills per consumer per year. However, we also considered that modelling did not give the full picture. For example, the modelling could not take into account more complex effects on generator behaviour resulting from both the implementation of WACM 2 and from the Capacity Mechanism. We considered that these effects, along with wider strategic benefits which could not be monetised, would result in long term benefits to consumers. We sought industry views on our analysis.

2.46. We have considered the responses to the April 2014 consultation and remain of the view that implementing WACM 2 will be in the interests of consumers.

Impact assessment modelling

2.47. Modelling all the interactions within the energy market is very complex and it is not possible to develop a model to capture this with a high degree of accuracy. The Baringa modelling results show that at worst, the impact on consumers is only 0.31% of the total value of wholesale prices in the model. This is well within the range of modelling error for a model of this type. Small changes in assumptions could materially change the results. For example, the model is very sensitive to the assumption regarding the marginal plant in the Capacity Mechanism. This is assumed

13 http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2014.pdf

in most years to be conventional plant located in areas which see an increase in transmission charges under WACM 2. If the marginal plant is further north, this would have a significant impact on results. For example, one respondent noted that in their view, it was more likely that existing mothballed gas plant in the North which faced lower TNUoS charges as a result of WACM 2 would be the marginal plant than was shown in the modelling.

2.48. We presented two modelling scenarios for the potential impact on consumers in our April 2014 consultation: an Original Case based on the assumptions used for the modelling in the August 2013 impact assessment updated to reflect more accurately DECC's latest position on the Capacity Mechanism and an Alternative Case with some additional changes to assumptions. Since our April 2014 consultation, DECC have updated its policy on the Capacity Mechanism to now include the contribution of interconnectors to security of supply when calculating the amount of capacity to be procured under the Capacity Mechanism. It will assume 75% of interconnector capacity to continental Europe can be relied on at times of system stress. This is broadly consistent with the assumption we make in the Alternative Case.

2.49. In addition, none of the scenarios presented contained an assumption on demand side response (DSR). In its updated Capacity Mechanism policy, DECC stated that it believes 2.6GW of DSR will be procured by 2019. We would expect this amount to also grow over time. As a result less capacity will need to be procured than has been assumed by Baringa in its modelling. This will reduce the modelled impact of WACM 2 on capacity payments.

2.50. We also consider that higher wholesale prices combined with lower costs shown in the modelling of power sector costs suggests that generators experience higher profits under WACM 2. However, the modelling does not fully consider how generators might respond to this. For example, the model does not allow sites outside a range of pre-identified options to be developed. This limits how potential benefits from competition and more efficient investment decisions arising from more cost reflective charges are captured. In addition, only simplistic bidding behaviour in the Capacity Mechanism is assumed.

2.51. The impact of a more competitive market will be more complex than assumed in the modelling. The impact assessment modelling clearly shows substantial additional profits for generators from implementing WACM 2 of up to £1.5 billion over the life of the modelling period. This exceeds the potential cost to consumers. Analysis of the distributional impacts of WACM 2 shows that generators in all locations will benefit from higher profits over the modelling period. This additional profit will in the long term lead to existing generators choosing to stay open and/or new participants entering the market, including new entrants not currently foreseen in our modelling. If generators enter 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. In addition, the threat of new entrants will also result in existing generators bidding more competitively to retain their market share. This behaviour is supported by the existence of higher profits. We therefore consider that in the long term the differential in consumers' bills between the status quo and WACM 2 is likely to be reversed.

2.52. Some respondents to the April 2014 consultation said that we have not considered the risk that the impact on consumers could be higher than that shown in the Baringa modelling. However, we carried out a range of sensitivity testing which was presented with the further consultation. The impact on consumers under all these scenarios was lower than that in the Original Case. We also note that the recent policy announcements by DECC on the Capacity Mechanism show that the modelling is suggesting an impact on consumer bills closer to £0.05p than £0.75p Finally, we consider that as the generation market is competitive, it is reasonable to assume that in the long run that generators will respond in a way that erodes the level of additional profits under WACM 2 currently shown in the modelling.

Alternative modelling

2.53. RWE presented revised modelling of the impact on consumers by NERA/ICL as part of its response to the further consultation. It previously presented modelling that showed that in its view, the cost to consumers over the modelling period was in the region of £6.6 billion. It has now updated the modelling and its view of the potential impact on consumers has more than halved to £2.7 billion. We note this is a very significant improvement in its results. While, as outlined below, we do not think that the NERA/ICL approach is an improvement on that taken by Baringa, we consider that shifts in results of this magnitude resulting from changes in assumptions further illustrates the difficulties of relying too heavily on this type of modelling.

2.54. We have considered the revised NERA/ICL modelling. The changes to the methodology have addressed some of our previous concerns. But we still think that the Baringa modelling more reliably reflects the relevant inputs and interactions to the extent it is possible in a modelling exercise. For example, we would expect to see a close relationship between the increase in TNUoS charges for marginal plant and the increase in capacity payments under WACM 2 as the marginal plant increases its bid into the Capacity Mechanism to cover its additional costs. This occurs in the Baringa modelling where average increase in TNUoS is £2.4/kw and average increase in capacity payment is £3.0/kw. In the NERA/ICL model the average increase in TNUoS is £4.5/kw but this drives a much larger increase in capacity payments with these going up by £7.5/kw. This drives NERA/ICLs results. If this effect was corrected, then we would expect to see the NERA/ICL and Baringa results converge.

2.55. In its response to the further consultation, RWE highlights one specific area where it considers the Baringa modelling underestimates the potential impact of Option 2. NERA/ICL's modelling methodology assumes that there is a range of load factors for onshore wind sites within 21 modelled onshore wind regions. Baringa assumes a single load factor for each of England, Scotland and Wales. We have no evidence of the extent to which this assumption drives its results. We consider that the impact of the higher capacity payments noted above is a much greater driver of the differences between the two models. We do not consider that the range of results presented by Baringa understate the potential impact on consumers of implementing WACM 2.

2.56. Some respondents to the further consultation noted that the potential future benefits for consumers were all long term, and that there would be costs to consumers in the short term which were more certain. They also point to other potential changes to the market such as those that may be brought about by implementing bidding zones within GB. In their view, this undermines the potential for long-term benefits arising from implementing WACM 2. We agree that benefits are likely to be seen in the long term, consistent with the fact that TNUoS sends a long-term signal. We would not expect to see short-term benefits arising from a change to the TNUoS methodology. We have considered whether there are any other changes in the shorter term that would reduce the likelihood of long term benefit accruing. There will always be changes in the market, but we do not believe that any are sufficiently certain to influence our decision on this modification. We also consider that a more cost reflective charging methodology will provide a better basis for future policy.

Wider benefits

2.57. Our statutory duties extend to considering the wider benefits to consumers alongside the impact on consumers' bills. This includes considering the interests of consumers in 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 consider that WACM 2 furthers our objective in these areas.

2.58. Transmission charging is not the primary way in which the government's environmental targets are met. Our modelling analysis assumes that the 2020 renewables targets are met in both scenarios, with a competitive allocation of Contracts for Difference (CfD)[14] support constrained by the level of available budget. However, the Baringa analysis shows that CfD strike prices[15] are lower under WACM 2 than the status quo. This makes it more likely that future renewables targets will be met, and this would be in the long-term interests of consumers. This benefit cannot be captured in the modelling.

2.59. We do not consider that implementing WACM 2 will affect security of supply. The Baringa modelling suggests that the de-rated capacity margin is broadly equivalent between WACM 2 and the status quo in each of the scenarios. This is because of the effect the Capacity Market has on stabilising the capacity margin.

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[14] CfDs are the new support regime for medium to large scale renewable energy supports. They will replace the existing renewable obligations from 2015.
[15] Under a CfD contract, a renewable generator will receive a payment equal to the difference between the wholesale price for electricity and the strike price. The strike price is set at a level which is estimated is needed to bring forward investment in that technology.

2.60. We note that some respondents have suggested that WACM 2 increases the risk that a marginal generator could close early and this would contribute to near term security of supply risks which would not be in consumers' interests. Our view is that this does not present a material risk to security of supply. We consider that WACM 2 is only likely to impact on retirement decisions at the margin and, overall, transmission charges are a relatively small part of the overall decision-making process. The main drivers of plant retirement decisions over the next few years are the Large Combustion Plant Directive and relative commodity prices of coal and gas. In addition, we note that the recent reform of cash out arrangements and the additional balancing services that National Grid in its role as System Operator will be able to procure over the coming winters has reduced the risk of consumers being impacted by tightening margins. We would expect any additional costs of these from implementing WACM 2 to be small compared to the potential for longer term benefits for GB.

2.61. We have considered the modification proposals against the requirements of European law. European legislation does not expressly require us to retain the status quo or implement WACM 2. It does require Ofgem to pursue a number of key objectives aimed at greater European integration. These include promoting cost-effective, secure and efficient network development and avoiding unjustified discrimination (including against renewable generation, particularly in remote locations). We consider that as WACM 2 is more cost reflective it is consistent with this.

Conclusions

2.62. We have concluded that WACM 2 better facilitates the relevant CUSC objectives than the status quo because it results in more cost reflective charges, increases effective competition compared to the status quo and better incorporates developments in the transmission licencees' transmission businesses. It also better facilitates the Authority's principle objective of protecting the interests of existing and future consumers. Of all the proposals put to us under CMP213, our view is that WACM 2 best meets these objectives. We have therefore decided to implement WACM 2.

3. Decision – implementation date

Chapter Summary
We explain our decision for the date from which WACM 2 should be implemented.

3.1. In reaching our decision on an implementation date, we considered three options: implementing from 1 April 2016, implementing from 1 April 2015 or a mid-year change in tariffs during 2014/15 charging year. We have considered the evidence presented to us by industry in reaching our views.

3.2. Our decision is that WACM 2 should be implemented with effect from 1 April 2016. This is the first date that industry can respond to the change by adjusting TEC without incurring a penalty under the user commitment arrangements. The views of respondents to the consultation and the factors we have taken into account in our decision are set out below.

Respondent's views

3.3. We explained in our April 2014 consultation that an implementation date earlier than 1 April 2016 would mean that parties might increase hurdle rates for future generation investment as they would have greater uncertainty about their ability to respond to changes in future. This could adversely affect competition in the generation market and harm consumers. Earlier implementation could also lead to suppliers including greater risk premiums 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. We asked industry for views on this.

3.4. Some respondents to the consultation supported the view that it was important to give industry time to respond to the change without incurring penalties. However, some respondents thought that it was important to effect the change more quickly. The arguments they made can be summarised as follows:

- Earlier implementation would allow the benefits of WACM 2 to be realised sooner.
- Industry expects TNUoS to vary between initial forecasts and final setting of the tariffs. If WACM 2 was implemented on 1 April 2015, the change to the tariffs currently forecast for 2015/16 would not be exceptionally higher than historic levels of variation in tariffs between forecasts and actuals.
- An implementation date of 1 April 2016, which is two years later than originally signalled in our August 2013 consultation, could result in investors perceiving there to be increased policy risk associated with investment in low carbon technologies.
- There is no evidence that an early implementation date would increase hurdle rates for generators or increase risk premiums for suppliers.

Industry has anticipated this change for some time and therefore has already factored the impact of WACM 2 into its plans.

- Other industry code modifications have been implemented more quickly.

Our views

3.5. WACM 2 represents a significant change in the charging methodology. As a result, considerations of regulatory risk must play an important part in our decision as to when it is appropriate to implement it. Implementing a significant change without giving generators an opportunity to adjust their TEC without incurring penalties will send a signal to industry that it can in future expect not to receive sufficient opportunity to respond to other significant changes. Our view is that this would increase the perception of regulatory risk and have a negative impact on consumers. While our minded-to position has been known for some time allowing parties to consider how this might affect their decisions in the event WACM 2 was approved, there is no certainty for generators to act on this until after our decision.

3.6. We have considered whether there are any benefits to consumers that would override potential costs from increasing regulatory risks. The benefits from WACM 2 will arise in the long term as TNUoS charges send a long term signal to participants about where to site new generation. As a result of now having certainty over the basis of future tariffs, generators will be able to start accounting for this in their planning. As a result, in our view it is unlikely that an earlier implementation date will change the long term outcomes of implementing WACM 2 or bring the benefits significantly forward.

3.7. We note that there is currently variation between forecast and actual tariffs and that implementing tariffs from 1 April 2015 could result in tariffs for 2015/16 being within the range of historic variation. However, parties currently expect this difference, and factor this into risk premiums. By implementing WACM 2 we would be adding more volatility in tariffs for 2015/16 over and above that already accounted for. We are of the view that this could cause parties to add additional risk into their future decision-making and would not be in the interests of consumers.

3.8. We note that decisions on an implementation date must be made on a case-by- case basis. There may be circumstances that mean that the benefits from an earlier implementation outweigh the potential for increased regulatory risk. In addition, there may be mitigating measures to reduce this risk such as phasing implementation. We do not consider that there are any mitigating measures that could be applied in this case.

3.9. We therefore remain of the view that considerations of regulatory risk take precedence in this case. Our decision therefore remains consistent with our April 2014 minded-to position and is to implement in April 2016.

Appendices

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Appendix 1 - Evolution of Project Transmit

The aim of Project TransmiT was to ensure that we have in place arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure and high quality network services at value for money to existing and future consumers. From its inception, it has been an open and transparent process. The main steps in the evolution of the project are summarised in this section.

Scope of Project Transmit

We launched Project TransmiT in September 2010 with a call for evidence on the issues that should be included. We also appointed a number of teams of independent academics to produce reports on the GB charging arrangements.

We established a dedicated web forum for Project TransmiT which provided stakeholders with an opportunity to contribute to the project by providing analysis and papers that could be posted on the Ofgem website. This was extensively used as a means of contributing to the body of evidence and stimulating debate.

We issued an open letter in January 2011, explaining that based on the response to the call for evidence, the scope of Project TransmiT would be electricity connection issues and electricity transmission charging. We identified a range of options to address these issues.

In May 2011 we consulted on how best to carry forward our work on Project TransmiT. This included a proposal to launch a Significant Code Review (SCR) on electricity transmission charging arrangements which would focus on possible short-term changes to the TNUoS arrangements.

We noted that we had identified some options for change that would require change to the wider GB trading arrangements. However, our preference was to limit the scope of the project to options to change transmission charging (TNUoS) alone as that that would be likely to deliver benefits to consumers more quickly. For similar reasons we also proposed to rule out fundamental changes to the structure of electricity transmission charging.

Significant Code Review

There was broad consensus from industry in support of our decision to exclude options that implied potentially more fundamental change from the scope of Project TransmiT and the SCR. Therefore, in July 2011 we launched a SCR to assess a range of potential options for TNUoS changes.

To help us identify and develop the technical detail of potential alternative charging methodologies we established and chaired a technical working group of 14 industry participants, representing a wide range of stakeholder interests. The working group met eight times between July and November 2011. They examined the issues raised by stakeholders and considered the range of possible options for change. They arrived at a view of the most appropriate alternative charging approaches. Agendas, papers and minutes for the workgroup meetings, together with the workgroups report were made available on our website.

We appointed external consultants, Redpoint Energy Limited (now part of Baringa Partners LLP(Baringa)), to carry out detailed modelling work for the SCR. This identified the potential impacts of the different candidate options for change.

On the basis of the work carried out by the working group and Redpoint, we identified three broad options which we could assess against the objectives of Project Transmit. These were:

- Retaining the **status quo**
- Introducing incremental changes to the methodology to better reflect the differing impacts that the different types of generators have on the costs of the transmission system (**Improved ICRP**)
- Recovering transmission costs through a uniform tariff, whatever the type or location of the particular generator (**Socialisation**)

During this process, we held two wider stakeholder events to provide general updates on the progress of our work including presenting the initial modelling results of the options.

In December 2011 we consulted stakeholders on our assessment of the impacts of the potential options, and our initial views on the way forward. We proposed not to progress a socialised charging approach as an option. Instead we considered Improved ICRP to be the right direction for transmission charging and that further work should be carried out by industry to refine this approach. We held two further stakeholder events to inform industry about the analysis and seek initial views.

In May 2012, having reviewed the responses to the consultation we concluded that we should progress Improved ICRP. We then directed NGET to raise a modification proposal to the TNUoS methodology.

The code modification process

In June 2012 NGET raised a formal modification proposal in accordance with our direction. This initiated an industry-led process to develop and consider options to improve the current ICRP transmission charging methodology via the CMP213 Workgroup. On 14 June 2013 the CUSC Panel submitted its final modification report to Ofgem for our consideration.

We consulted twice on the proposals and our assessment of the impact of these. This document sets out our final decision to approve one of the options.