Annex 1

We appreciate that this consultation is focussed just on the additional new information that is covered in this latest 25th April 2014 consultation. As such we have refrained from repeating here the substantial arguments, and supporting evidence, that we have provided on numerous previous occasions in response to earlier Authority, Ofgem and industry consultations on Project Transmit and CMP213. However, our responses to those previous consultations have a material bearing on any decision with respect to CMP213 and should, therefore, be taken into account when the Authority is making its decision on CMP213.

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

Whilst we agree with the Authority's interpretation of the high-level benefits to consumers of implementing WACM2, we do not agree with the quantitative modelling that accompanies this assessment in several aspects. We consider that the consumer impact outlined in the revised Impact Assessment modelling overstates the net cost to consumers in both the short and long term for the Original case and in the short term in the Alternative case. The costs outlined are small but we believe that given the uncertainty it would have been more appropriate to demonstrate a range of costs where the expected value is zero. This would have highlighted that the decision should be based on the principles of making the WACM2 change rather than the revised impact assessment modelling results in the latest consultation.

We agree with Baringa[1], in their latest assessment, that "*...WACM2 generally better reflects the relevant investment principles and is likely to be a better reflection of the relative cost impacts of generators on transmission investment costs, all other things being equal.*"[2]

We agree that WACM2 is more cost reflective and agree with the Authority's statement, in the latest consultation document, that "*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*"[3]

This is reinforced by the Phil Baker critique, which noted that:

> "*Implementing WACM2 would also deliver a number of "dynamic effects" referred to by Ofgem in their further Consultation document. The more cost-reflective locational signals delivered by WACM2 would result in benefits such as more efficient policy decisions such as the substitution of expensive offshore wind with cheaper onshore capacity, more efficient transmission investment, and more efficient investment decisions in relation to new plant*

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[1] We wish to record our agreement with the statement from Lane, Clark and Peacock LLP in their 'Quality Assurance of CMP213 Modelling' that, in respect of the Baringa modelling, they "...have reviewed certain elements of the updated CMP213 modelling and have found no issues with the implementation of the agreed methodology that we believe would materially affect the conclusions reached from the modelling results".

[2] Baringa: Further Analysis and Review of Consultation Responses (25th April 2014) page 10

[3] Ofgem, 25th April 2014 para 2.24

and the maintenance, operation and life-extension of existing generation plant."[4]

The Oxera review[5], counters the claims made in response to previous consultation that WACM2 is less cost reflective than Status Quo:

> *"Overall, we do not believe that the logical conclusion from the modelling results derived by NERA/ICL is that WACM2 charges are less 'cost-reflective' than charges under the status quo."*[6]

We agree with the Authority that WACM2 is less discriminatory as "*the benefits from the improvement to cost reflectivity reduce discrimination*"[7]. Therefore by inference Status Quo is more discriminatory. It follows that WACM2 should be introduced at the earliest opportunity since there is an absence of any compelling evidence to the contrary which would justify delaying the replacement of the discriminatory Status Quo methodology.

We agree with the Authority's conclusion in the latest consultation that WACM2 would increase effective competition because it is more cost-reflective and less discriminatory.

We agree with Baringa's latest assessment that the impact of WACM2 would be to deliver a more efficient price signal which would give better overall balance of reduced generation costs and increased transmission costs. This more efficient price signal may be expected to deliver a lower cost outcome therefore lowering costs to customers over the medium and long term.

Overall Baringa's latest modelling shows the impact on customer costs between the Status Quo and WACM2 is small in the context of EMR[8], and so there is no reason, in our view, not to introduce the more cost reflective WACM2 charging methodology.

In the following section we comment on aspects of the Authority's assessment focussing on power sector costs, customer bill impacts and missing dynamic effects highlighting areas where we agree with the Authority's conclusions and areas we think give further support to the 'minded to' approve WACM2 position.

Power Sector Costs Impact

We agree with the Authority statement, in this latest consultation, that "*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.*" [9]

We agree this reduction in power sector costs and higher generator profits modelled under WACM2 is likely to feed though to lower costs to customers through dynamic effects outside of the scope of the modelling.

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[4] Baker, 27th May 2014, section 7.2
[5] Oxera, 27th May 2014
[6] Oxera, 27th May 2014, Executive Summary, page 2
[7] Ofgem, 25th April 2014 para 1.58 (pg 40)
[8] Baringa, 25th April 2015 page 69
[9] Ofgem, 25th April 2014 para 2.39

We agree with the Authority view, in this consultation, 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.*"[10]

In the long term WACM2 will deliver a reduction in power sector costs because the savings in generation costs outweigh any higher transmission costs that arise because of any increased transmission investment that results from the modified locational incentive/signal.

We agree with the Authority that these long term savings in generation costs could be expected to flow through to even lower costs to customers through dynamic effects outside of the scope of Baringa's modelling as described below:

> "*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*" [11]

However, we also think that WACM2 will deliver short term benefits through reduced CfD costs, as recognised by the Authority, *"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."* [12] Given that the CfD arrangements will enter into force as early as this current 2014/15 charging year we consider that the Authority should, by their own reasoning, seek to implement WACM2 as early as possible in order to help see the cheapest CfD generation projects being developed.

Customer bill impact

The customer bill impact is mainly a trade-off between higher Capacity Mechanism costs and reduced low carbon support costs.

The result of the Baringa modelling is very sensitive to the input assumptions made in developing the model(s) (for example if the outturn market required a lower generation capacity receiving Capacity Mechanism payments, then this would reduce the negative customer impact of WACM2, as compared to the alternative scenario).

We agree with the Authority that the modelled increase cost per customer is very small and can be considered to be well within the normal (and widely accepted) margin of error of the type seen with complex modelling, such as that undertaken by Baringa (and indeed NERA/ICL). Given this we consider that Ofgem should conclude and state clearly that the Baringa modelling effectively illustrates that the change to WACM2 would have at worst a neutral impact on the expected costs to end customers in the short term where the range of outcomes modelled is limited. This then allows the impact of WACM2 to be judged on the higher level benefits.

[10] Ofgem, 25th April 2014 para 2.41
[11] Ofgem, 25th April 2014 para 2.40
[12] Ofgem, 25th April 2014 para 1.53 (pg 39)

It appears that consideration of the higher principles is the approach that is being used to develop the way forward with respect to the Electricity Balancing SCR ('EBSCR'). We consider that the Authority's approach to the implementation of WACM2 is in general consistent with the EBSCR developments and decision(s) that were recently announced by the Authority and, given this, a similar approach regarding early implementation, than 1st April 2016, should be adopted for WACM2.

We agree that WACM2 is unlikely to result in any change to the consideration of variable costs regarding power station dispatch decisions because of the five year historic average plant load factor approach which means that any impact is diluted and dominated by other much larger factors.

We also note that Baringa identify that "...*any generation cost increases due to dispatch distortions are likely to be outweighed by much larger reductions in constraint costs and transmission losses. The distortive incentives would provide a signal for generators in the south to run more and those in the north to run less, and so if anything making WACM2 more reflective of underlying costs*."[13]

The Baringa modelling only goes out to 2030, which is relatively short in terms of the long-term investment decisions of generation plant, so we would expect WACM2 to continue to deliver increasing benefits to customers over the even longer term (beyond 2030).

Dynamic effects

We agree with the statement, in the latest consultation, that "...*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*."[14]

We also agree with the statement, in the latest consultation, that "...*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.*" [15]

We agree that the Authority is correct, in the latest consultation, to place a high level of emphasis on the likely medium and longer-term customer benefits of switching to WACM2.

We agree with the assessment by both Baringa[16] and the Authority[17] in this latest consultation that WACM2 is more cost reflective and will therefore deliver a more efficient result and lower costs to customers over the long term.

We agree with the views of Baringa and the Authority to reject the criticisms arising from NERA/ICL paper on customer costs.

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[13] Baringa, 25th April 2014 page 10
[14] Ofgem, 25th April 2014 para 2.40
[15] Ofgem, 25th April 2014 para 2.43
[16] Baringa, 25th April 2014 page 18 "*Overall, we believe that the WACM2 methodology is more cost reflective than the Status Quo in recognising the dual drivers of transmission investment*"
[17] Ofgem, 25th April 2014 para 2.51

In coming to our view we have been mindful of the Authority's views on consumer costs and modelling and in particular:

> "*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*."[18]
>
> "*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*."[19]
>
> "*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*."[20]

We also agree that some of this benefit to customers will include dynamic effects which were beyond the scope of modelling objectives of Baringa. While Baringa have carried out a useful selection of modelling sensitivities, it is not possible or practical to model every circumstance and it is likely that a wider range of scenarios, or consideration of how the two charging methodologies may respond to shocks to the generation mix could highlight the longer term benefits of WACM2. There are a wide range of potential dynamic effects which could include:

- **Improved security of supply** – If WACM2 resulted in more onshore wind build in Scotland and more transmission network capacity is built between Scotland and England, then a larger interconnected area would result in better security of supply. This is because failures of individual generation units or sudden load surges could be absorbed more easily and it may be easier to deal with the failure of a power line, resulting in lower costs to customers.
- **Renewable portfolio benefit** – WACM2 may facilitate renewable generation to be built over a more diverse geographic area with a lower correlation of output between stations. This may have multiple benefits including reducing the intermittent nature of the GB renewables generation fleet, increase the level of sharing to reduce the average cost of transmission, reducing total forecast error and reducing system imbalance costs, all of which could deliver lower costs for customers.
- **More bidders in the balancing market** – Under WACM2, if there are more renewable generators in Scotland, then there will be a higher level of competition in the balancing market in the event of constraints. As with any market, a higher number of bidders and a higher level of competition may apply greater downward pressure on the price of balancing services.
- **Lower cost of transmission reinforcement** - We expect that the construction of the HVDC 'bootstraps' will make it easier and more economic to identify and carry out more onshore reinforcement since it will reduce the constraint costs which could be expected to arise from any onshore transmission outages.

[18] Ofgem, 25th April 2014 para 2.24
[19] Ofgem, 25th April 2014 para 2.38
[20] Ofgem, 25th April 2014 para 2.40

Baringa highlight that "*Were onshore transmission reinforcements available rather than more expensive HVDC bootstraps we expect that the savings demonstrated under WACM2 would be greater*."[21] Baringa's modelling was based on a fixed list of potential reinforcements.

- **Impact of DSR on Capacity auction** – We agree that the interaction of demand side response with the capacity mechanism, which was not fully included in Baringa's[22] modelling, could further increase the benefit of WACM2 over the Status Quo by reducing the impact of the cost of the capacity market.

- **More efficient policy decision regarding optimal mix between capacities of different low carbon technologies** – Whilst Baringa's decision to fix the ratio of capacities between different low carbon technologies improves the transparency of the modelling process, it understates the benefits of reducing power sector costs and cost to customers by reduced low carbon support costs that WACM2 brings. It is likely that following the introduction of WACM2, it would be a more efficient to build more lower cost onshore wind in the North instead of higher cost offshore wind in the South and this may occur either through more efficient policy decisions, or competition between technologies in the allocation rounds. Baringa state that "*If in the longer run onshore wind and offshore wind were to compete for CfDs in the same auction, changes to transmission charges might be a more significant driver of the renewables mix than assumed in this modelling.*" [23] The Authority also outline they expect this impact in the consultation document[24] as described above.

- **Incentivising locally appropriate plant mix**– The Status Quo is referred to as using a single Peak Security background, but it does not adequately deal with the issue of peak security which occurs when wind output is relatively low, while WACM2 does introduce an important change to the Peak Security approach by assuming zero wind in the Peak Security background.

    - For example, if there was a shortage of dispatchable generation plant in Scotland which may lead to security of supply issues and a risk of lost customer load, then Status Quo would continue to provide a perverse price signal to generators to avoid building peaking plant in Scotland. This would exacerbate the problem and further increase costs for customers. By contrast, WACM2 would appropriately provide very different price signals for peaking, baseload and intermittent generation. This would incentivise the building of a more appropriate plant mix which would help rectify the local security of supply issue. This in turn would result in lower overall costs for customers and increase in customer value through reducing the likelihood of lost customer load.

    - A second illustration may be if a there was a higher level of new generation build of offshore wind in the South of England instead of

[21] Baringa, 25th April 2014 page 10
[22] Baringa 25th April 2014 Annex 3
[23] Baringa, 25th April 2014 page 9
[24] Ofgem, 25th April 2014 para 1.53 (pg 39)

onshore in Scotland, then Status Quo may have the perverse effect of flattening the gradient of the TNUoS tariff to weaken the signal to build dispatchable generation plant in the South of England, hence this could result in security of supply issues in the South of England resulting in higher costs for customers. By contrast, the dual background approach of WACM2 will provide a more appropriate peak security price signal and thus deliver lower costs and greater value to customers in this circumstance.

- **We agree with the Authority[25] that under WACM2, there is an increased likelihood of meeting the UK Government's low carbon targets** - This will support long term government policy to deliver more renewable energy and lower carbon generation, which will reduce the likelihood that the UK government may need to take more urgent action at higher cost to customers in order to meet these targets.

- **Lower Capacity Mechanism clearing price due to negative Peak Security tariff** – It is possible, as per Baringa's August 2013 modelling, that plant opening and closing decisions could result in a negative peak security tariff in Scotland. If the marginal generation plant which set the clearing price in the capacity mechanism was an OCGT power station, then the negative peak security charge and low ALF could make it a lower cost to locate in Scotland, which may result in a lower capacity mechanism cost to customers compared with the Status Quo. In this way WACM2 could result in a lower cost to customers because it resulted in a lower cost of both low carbon support and lower cost of the capacity mechanism payments.

- **Lower Capacity Mechanism clearing price due to use of ALF –** Depending on the charging zone, the use of ALF may substantially reduce the cost of an OCGT within the capacity mechanism as compared with under the Status Quo. If an OCGT was the capacity mechanism clearing plant, then this may result in a lower capacity mechanism clearing price as compared with the Status Quo, hence reduce costs to customers.

WACM2 provides a number of additional consumer benefits which we agree should be factored in to the Authority's decision to implement WACM2.

- **Improved policy making on the back of having more efficient market outcomes arising from more cost-reflective charging.** WACM2 is more cost reflective, so should be more efficient and lead to more efficient.

- **The moderating impact of DSR on Capacity Market clearing prices –** We agree that the interaction of demand side response with the capacity mechanism, which was not fully **i**ncluded in Baringa's modelling[26], could further increase the benefit of WACM2 over the Status Quo by reducing the impact of the cost of the capacity market.

[25] Ofgem, 25th April 2014 para 2.47 "*The modelling demonstrates that implementing WACM 2 increases the likelihood of meeting renewables targets for a given low carbon support budget*."
[26] Baringa, 25th April 2014 page 86

- **Impact of optimal low carbon technology mix.** The Baringa modelling assumes the capacity mix is fixed. "*If in the longer run onshore wind and offshore wind were to compete for CfDs in the same auction, changes to transmission charges might be a more significant driver of the renewables mix than assumed in this modelling.*"[27] The change in generation mix that is likely to result from the implementation of WACM2 could lead to a significant reduction in the cost of low carbon generation support which will benefit customers. This is recognised by the Authority[28], as described above.

- **The modelled increase in profitability of generators under WACM2 should feed through to lower customer bills by encouraging more new entrants at lower cost**. This benefit would go beyond the Baringa modelling approach because the latest Baringa modelling was based on a specific list of potential new entrant generation sites. This list is common to both their Status Quo and WACM2 model. However, in practice a more efficient TNUoS charging methodology will encourage the development of more innovative solutions to deliver more generation capacity more cheaply, such as identifying new sites, or taking additional steps to extend the life of operating power stations. The greater level of older generation life extension arises because WACM2 delivers greater charging cost reflectivity for plant moving down the merit order due to the incorporation of load factor in the price signal.

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

We are satisfied that Baringa has addressed the issues raised regarding:

- **The impact of the higher level of renewable generation in Status Quo compared to WACM2** - We agree that it is appropriate for the modelling to assume an equal level of renewable penetration between the modelling scenarios for Status Quo and WACM2. However this does result in under-valuation of WACM2 as it ignores the fact that WACM2 is likely to help in practice with the deployment of lower cost renewable, namely wind in Scotland, which will allow for more renewable production for the same overall cost.

- **The impact of volatile capacity margins on wholesale prices –** We agree that it is appropriate to model a flat capacity margin between the scenarios for Status Quo and WACM2. However, this is likely to undervalue WACM2 as the model does not capture impacts arising from WACM2 which are likely to increase capacity margins all else being equal.

- **Possible distortions to dispatch from the ALF element of WACM2 –** We agree that the ALF element of WACM2 will have a minimal, or no significant impact on generation plant dispatch decisions, and so we support the latest view from Baringa that "*...the potential dispatch distortion from WACM2 is*

[27] Baringa, 25th April 2014 page 9
[28] Ofgem, 25th April 2014 para 1.53 (pg 39)

likely to be small and have only a marginal impact on generation costs and wholesale prices. In addition, if dispatch distortion did occur they would lead to reductions in constraint costs and transmission losses, due to a marginal decrease in generation from more northerly generators."[29]

- **The impact of the low carbon generation mix –** We support Baringa's decision for their latest modelling to maintain a fixed allocation between low carbon generating technologies under both Status Quo and WACM2. This approach makes the modelling more transparent and objective so it is easier to understand the moving parts which are included in the model. However, this approach to fix the generation mix likely results in under stating the benefits of WACM2. In practice, we would expect the more efficient price signals from WACM2 to result in more efficient policy decisions, which could result in meeting renewables targets and low carbon targets at an even lower cost if the mixture of low carbon technologies was able to adapt in response to changes in the TNUoS charging methodology.

We also believe that the modelling has successfully fulfilled the need for additional sensitivity analysis. We welcome the inclusion in the latest Baringa modelling of additional sensitivity tests to consider higher penetration of renewables, variations in gas prices, coal prices and the de-rating factor for interconnectors. The process of modelling the future electricity market is complex and there will always be more combinations of different sensitivities which could be considered. However, it is not possible or practical to model every eventuality and Baringa takes a reasonable approach to providing results to a reasonable range of sensitivity scenarios. In this regard we note that those parties that argue for yet more modelling of even more variables to be undertaken seem, in our view, to be doing so in order to just delay the CMP213 decision process rather than to achieve anything meaningful as a result of the modelling – they seek paralysis by analysis as a means of putting off to a much later date the implementation of a change they know to be fundamentally correct.

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?

We agree with the Authority's minded to position, in light of the new evidence which has been presented in the consultation document, and we discuss below these four areas of new evidence set out in the consultation document.

<u>(i) Cost reflectivity</u>

We agree that the issues regarding the cost reflectivity of WACM2, raised by NERA/ICL, in their February 2014 document, have been adequately addressed by the Authority in its most recent consultation.

We agree with the Authority's assessment that WACM2 is better than the Status Quo charging methodology in many important regards:

[29] Baringa, 25^{th} April 2014 page 20

- **Dual background better reflects the SQSS - We agree with Ofgem's assessment that** "*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*."

- **Application of the ALF better represents the impact on costs of different generators –** We agree that the use of the ALF is more cost reflective than the Status Quo and agree with the Authority's assessment that "*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*".[30]

Furthermore, we note, in passing, that NERA in a report in 2004 expressed their support for the principle behind the application of the ALF in WACM2 that plant with a lower availability will have a lower impact on transmission costs and stated that "*In reality, we would expect lower plant availability to increase spare capacity in the transmission network, and thereby reduce expansion costs, particularly in areas such as Scotland with high concentrations of hydro and renewables*." [31]

We agree with the Baringa view that the principles behind the WACM2 are better than Status Quo.

We agree with Baringa and National Grid's rejection of the concerns raised by NERA/ICL (and Poyry) regarding the principles behind the WACM2 approach. As stated by Baringa in their assessment

> "*National Grid has confirmed that the approach encapsulated in the WACM2 methodology, and modelled within the TDM, is an accurate reflection of how transmission investment decisions are assessed. Hence, in our opinion WACM2 is more reflective of a full CBA and therefore is consistent with investment principles, and certainly more consistent than the Status Quo approach to transmission charging which does not reflect the economy criterion at all.*"[32]

We agree with the Authority view, in the consultation, 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*."[33]

We have previously made a detailed case demonstrating the greater cost reflectivity of the approach represented by WACM2 due to the combination of the inclusion of the ALF, treatment of sharing and use of the proposed dual background. This evidence included quantitative modelling of a simplified network and a comparison with the SQSS of the implied charges arising from WACM2 and the Status Quo charging methodology. This clearly made the case that WACM2 is more cost reflective of the

[30] Ofgem 25th April 2014 para 1.18 (pg 30)
[31] NERA (2004), 'Review of GB-Wide Transmission Pricing: A Report for ScottishPower UK Division' section 6.5
[32] Baringa, 25th April 2014 page 4
[33] Ofgem, 25th April 2014 para 2.8

SQSS and therefore more cost reflective of a full cost-benefit analysis and the actual costs imposed by generators on the transmission system across a range of generation technologies and transmission charging zones. This previous evidence from us, and our advisers (Oxera and Phil Baker) comprehensively rejected the arguments made by Poyry[34], NERA/ICL[35], University of Bath[36], Centrica[37] and RWE[38] which questioned the better cost reflectivity of WACM2. This previous evidence provided by us, and our advisers, should be taken into account in the Authority's decision, but to avoid duplication, it has not been repeated here. This previous evidence from us included:

- SSE consultation response to Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, October 2013
- SSE letter to the Authority, 6th February 2014
- Review for SSE of Poyry's Report to Centrica Energy "Review of Ofgem's Impact Assessment on CMP213", Baker March 2014.
- Review of the NERA/Imperial College London report on the impact of the WACM2 charging model, Oxera, 27th February 2014
- University of Bath report "Year-round System Congestion Costs – Key Drivers and Key Driving Conditions": an alternate view, Baker October 2013
- Further analysis to provide a qualitative assessment of the three CMP213 Diversity options and of the potential for sharing in situations where more than one renewable technology is present, Baker October 2013

We agree with the views of Baringa and the Authority that it would be appropriate to reject the criticism of cost reflectivity from the NERA/ICL report and that by contrast, a more appropriate interpretation of the NERA/ICL analysis would be in support of the case that WACM2 is more cost reflective. We agree with the Authority that "*...in the majority of cases the NERA/ICL analysis suggests that WACM2 is closer to the measure of LRMC than status quo.*"[39] We consider that this can be restated as the NERA/ICL analysis illustrates that WACM2 is more cost reflective for almost all technology types for almost all generation TNUoS zones for almost all the time periods including for wind generation in Scotland in the period up to 2020.

- **NERA/ICL show that WACM2 is more cost reflective for Northern wind before 2020** - Regarding the NERA/ICL analysis, Baringa comments that "*In 2013, before HVDC bootstraps are built, the tariffs produced for wind across all TNUoS zones under the WACM2 methodology appear to be closer to the calculated marginal LRMCs than under the modelled version of the Status Quo methodology*." (Baringa 2014 3.3.)

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[34] Review of Ofgem's Impact Assessment on CMP213, Poyry, October 2013
[35] Project TransmiT: Modelling the Impact of the WACM 2 Charging Model, NERA/ICL, 9th October 2013
[36] Year-round System Congestion Costs - Key Drivers and Key Driving Conditions A report to Centrica and RWE, Li et al, University of Bath, January 2013
[37] Centrica consultation response to Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity charging methodology, Centrica 11th October 2013
[38] Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology - RWE response, RWE 10th October 2013
[39] Ofgem, 25th April 2014 para 2.15

- **NERA/ICL acknowledge that their model shows that WACM2 is more cost reflective for marginal gas plant (NERA/ICL 5.4.)** – NERA/ICL agree that their modelling shows that WACM2 is more cost reflective for marginal gas plant. They attempt to dismiss this result by claiming the increase in cost reflectivity will not have a material effect on investment decisions. However, investment decisions are based on a large number of different factors of which the TNUoS cost is only one part, so this an important result from the point of view of the principle of cost reflectivity and also from the point of view of more efficient investment decisions.

- **NERA/ICL modelling shows that WACM2 is more cost reflective for baseload gas and nuclear (NERA/ICL, 5.2.2)** – NERA/ICL claim that their modelling shows the cost reflectivity of WACM2 is similar to Status Quo, however, the results in their own graph clearly show that WACM2 is more cost reflective in this circumstance.

We agree with the Authority's view that "*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*."[40] We believe that our assessment above challenges the number of circumstances in which WACM2 may result in less cost reflective charges.

NERA/ICL's criticism of WACM2 rests on the individual case of Scottish wind after the commissioning of the Western HVDC bootstrap where they suggest that LRMC of Scottish wind would be greater than that suggested by the ICRP approach.

> "*...NERA/ICL's conclusions are not supported by the analysis they carried out. This report also shows that, had a less extreme assumption been made about future Scottish boundary reinforcement, WACM2 would be shown to be more cost-reflective than the Status Quo in virtually all situations*."[41]
>
> "*Overall, we do not believe that the logical conclusion from the modelling results derived by NERA/ICL is that WACM2 charges are less 'cost-reflective' than charges under the status quo*."[42]

Future transmission system reinforcements will be a blend of options cheaper than HVDC

We agree with the Authority's view that:

> "*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*

[40] Ofgem, 25th April 2014 para 2.20
[41] Baker, 27th May 2014 Executive Summary
[42] Oxera, 27th May 2014 Executive Summary page 2

> *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*".[43]

We also agree with the Baringa view that:

> *"The differences in ICRP tariffs will typically turn out to be a close match to the relative LRMCs of new investment where the variation in marginal investment fluctuates around a mean trend over a sustained period of time. For example, HVDC can represent a divergence from the mean trend, but it may be only a temporary divergence, in which case ICRP (on average over a sustained period of time) will produce tariffs that remain a close match to LRMC."*[44]

An important flaw in the NERA/ICL approach is that they assume that the North–South capacity of conventional overhead transmission lines cannot exceed 4.4GW, so by definition, they assume that all future reinforcement will be HVDC. In practice, this will not be the case and it is likely that further expansion will be built using lower cost technologies.

- **HVDC may play no part -** The Baringa modelling showed that in their Original case, there is no need for any additional HVDC reinforcement beyond 2021 within their modelling horizon. Therefore it may then be reasonable to assume that HVDC should play no part at all in the calculation of the LRMC of wind in Scotland.

- **More lower cost onshore expansion is available** - It may be possible to expand the capacity of conventional North–South overhead transmission lines beyond 4.4 GW, including the use of smart solutions to increase the transmission capacities of the existing lines at a lower cost than HVDC. National Grid's 2012 Ten Year Statement[45] shows a range of proposed reinforcement across the Northern system boundaries, including HVDC 'bootstraps' or links, AC circuit rebuilding and reconductoring, series compensation etc. The use of HVDC unit costs alone to define the LRMC of transmission therefore represents an extreme case and seems unlikely to reflect the range of transmission investment costs incurred over an extended time period. NERA, in a report in 2004, criticised the use of fixed expansion cost factors, as follows:

  > *"…'expansion constant' and 'expansion factors', which define the cost of these power flows in £ per MW km, overstate costs by ignoring the potential for low-cost methods of adding*

[43] Ofgem, 25th April 2014 para 2.17
[44] Baringa, 25th April 2014 page 37
[45] National Grid Ten Year Statement 2012, Appendix 3. http://www.nationalgrid.com/NR/rdonlyres/F4E4ADC3-C867-49AC-80E6-5997CEDF0A80/57727/ETYS_2012_Appendix_A3.pdf

transmission capacity that NGC has used extensively in the past."[46]

- **Western and Eastern 'bootstraps' may facilitate even more lower cost transmission reinforcement options -** Once these HVDC links are completed, it seems reasonable to expect that the additional dispatchable boundary capacity and doubling the number of transmission routes out of Scotland will reduce the congestion cost consequences of onshore AC outages. This would result in onshore AC reinforcement becoming a more attractive option and undermine the case for further HVDC reinforcement.

- **If an averaging approach was used for LRMC, then this could give a result close to ICRP** – We agree with the point made by Baringa in their review of the consultation responses[47], noting that while the high cost of HVDC transmission represents a divergence from the more averaged reinforcement costs underpinning ICRP-based charging methodologies, the divergence may only be temporary. Averaged over a sustained period, ICRP-based tariffs based on both HVDC and AC reinforcement costs may well produce transmission tariffs that are a close match to the LRMC of transmission.

- **NERA/ICL over state the gradient of relative charges of locational tariffs due to under estimating the cost of transmission reinforcement for Southern generators** – As noted by Baringa[48], the most appropriate test of cost reflectivity is the relative costs rather than the absolute levels. While NERA/ICL over estimate the cost of Northern reinforcement, as described above, they also under estimate the cost of Southern reinforcement and both of these combined lead NERA/ICL to produce a LRMC curve which over states the relative cost of Northern generators. National Grid provide the costs for a selection of reinforcement projects including those in England and Wales, which shows that Western HVDC is towards the lower end of this range.[49] Therefore, in practice, the cost of transmission system reinforcement is likely to be flatter with a more evenly distributed cost across North and South GB.

- **ICRP over states the relative cost of transmission system reinforcement in the North** – Further to the arguments above that the NERA/ICL analysis over states the difference in cost of transmission system reinforcement in £/MWkm between Scotland and England, this argument also implies that the ICRP transport model also over states the differential in reinforcement cost. Therefore, while WACM2 is more cost reflective than the Status Quo, WACM2 is still more likely to err on the side of producing TNUoS tariffs which still over state the transmission cost of northern generators. The ICRP approach assumes that the incremental cost of reinforcement can be

[46] NERA (2004), 'Review of GB-Wide Transmission Pricing: A Report for ScottishPower UK Division', p. ii.
[47] CMP213: further analysis and review of consultation responses (pages 37 &40). Report by Baringa to Ofgem, April 2014
https://www.ofgem.gov.uk/ofgem-publications/87397/redpointenergyreportonfurtheranalysisandreviewofcmp213consultationresponses.pdf
[48] Baringa, 25th April 2014 section 3.3
[49] National Grid (2011), 'NETS SQSS Amendment Report GSR009 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation', Appendix 5, April, pp. 58–59

represented by the average cost of the existing transmission network. It applies an expansion factor which is based on the reasoning that the average cost of the existing transmission network in Scotland in £/MWkm is more expensive than England and Wales, so the expected cost of reinforcement is also higher than England & Wales. However, as described above, a more appropriate geographical distribution of the cost of transmission reinforcement per MWkm may be even flatter than that assumed by the ICRP approach.

<u>(ii) NGET's modelling presented in our [the Authority's] impact assessment</u>

We welcome the additional cost impact modelling from Baringa. Whilst we have some reservations about the results we consider that they provide a compelling counter argument to the results presented by NERA/ICL.

We agree with Baringa's latest assessment that NERA/ICL's latest result can not be relied upon because the NERA/ICL counter intuitive result was due to artefacts of their flawed modelling approach regarding the allocation of low carbon subsidies which NERA have not been able to explain

"*We believe the NERA/ICL modelling approach suffers from a number of weaknesses, and counter-intuitive results which cannot be sufficiently explained. For example, we do not believe that an increase in transmission costs and generation costs under WACM2 is a likely outcome, since the incentives to relocate generation should lead to an increase in one and a decrease in the other. Therefore, we have concluded that the resulting significant net welfare dis-benefit for WACM2 shown by the modelling cannot be relied upon*."[50]

- Under WACM2 the NERA/ICL model fail to build the lowest levelised cost, highest load factor plant onshore stations in Scotland.
- NERA/ICL selects WACM2 generation plant outside of economic merit order, so their WACM2 result is less efficient due to their own assumptions, not as a result of a fundamental output of their model
- NERA/ICL assumed WACM2 resulted in more build of offshore wind at a higher cost to customers and that this displaced onshore wind. The additional cost arising from offshore wind displacing onshore wind appears to represent the bulk of the additional consumer cost reported by NERA/ICL. We agree with the Authority's rejection of the NERA/ICL results and consider that, given the sensitivity of consumer costs, that the Authority should make it clear that, given the opportunity of bilateral discussions, NERA/ICL were not able to help the Authority "*...to observe precisely which of these effects is driving the result*"[51]. This implies clearly that the results are not robust and should be discounted publicly.

<u>(iii) Consistency, non-discrimination and complexity</u>

[50] Baringa, 25th April 2014 page 22
[51] Baringa, 25th April 2014 page 31 (reference to "NERA/ICL, Sixth Response to Ofgem TransmiT Questions")

We agree with the Authority that the CMP213 arrangements do not "*...represent undue discrimination between participants in the market*"[52].

We consider however that remaining with the Status Quo does represent undue discrimination between participants in the market, especially given the evidence that has been presented by the Baringa modelling, ourselves, and others not least from the NERA/ICL modelling which in particular highlights that WACM2 is more cost reflective for most categories of generators in most locations than Status Quo.

(iv) Treatment of HVDC and island links

We agree with the Authority's view that *"...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*"[53]

We note the comments[54] that the costs of HVDC convertor stations are higher than AC substations. However, in our view, this is not a material consideration per se in terms of the charging methodology approach (of socialising that cost or not) as the same could be said about any element(s) of the transmission system; cable is more expensive than overhead line, tunnels are more expensive than cable etc.

The key question before the Authority, in respect of the treatment of HVDC, is 'Do elements of the HVDC 'bootstrap' (such as the convertor stations and undersea cable(s)) exhibit characteristics which are equivalent to elements of the onshore transmission assets which are socialised?' As we detailed in our response to the August 2013 consultation we believe there is evidence for this; both from the work of the CMP213 Workgroup but also the more recent technical work undertaken by international experts via the updated CIGRE detailed review and analysis of this technology.

We note the Authority's comment that it has been suggested by a respondent "*....that an AC line may have multiple substations*"[55] but that no evidence appears to have been forthcoming on this. We would observe that it should be possible for the System Operator to advise the Authority on the maximum distance, per AC kV capacity[56], in the existing GB transmission system between two substations and also what the average distance is. From that it should be a relatively simple exercise to deduce how many AC substations would have to be built for an equivalent onshore transmission line between, say, Hunterston and Deeside; assuming, for this purpose, that there were no other transmission assets in place.

In conclusion, taking account of the above four areas, overall we consider that the additional information that was provided by NERA/ICL has added nothing of substance to the body of evidence upon which the Authority has to make its decision.

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52 Ofgem, 25th April 2014 para 1.56 (pg 40)
53 Ofgem, 25th April 2014 para 1.65 (pg 41)
54 Ofgem, 25th April 2014 para 1.66 (pg 41)
55 Ofgem, 25th April 2014 para 1.68 (pg 41)
56 400 kV, 275 kV and 132kV

It is unfortunate that this has led to delay of the implementation at least to 1st April 2015 compared to the minded to position as at August 2013 (of 1st April 2014).

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

No. We do not agree with the Authority's 'minded to' position to implement on 1st April 2016 in three specific areas; (i) benefit (ii) consumer costs and (iii) precedent.

We believe that it is imperative to introduce WACM2 at the earliest possible date so that the long-term benefits to end customers can begin to be realised at the earliest opportunity. These benefits will include the CfD competitive allocation round for plant commissioning in 2015/16, so an implementation date, for WACM2, any later than 1st April 2015 would already delay these benefits being realised by customers.

We consider that the Authority's latest assessment has shown that the delay following on from the August 2013 consultation was unnecessary and that given this the correct response of the Authority would be to stick with their 'minded to' position to implement on 1st April 2015 as outlined in December 2013 as at least this would reduce the impact of the delay.

We address each of the specific areas in turn.

<u>(i) Benefits</u>

We do not agree that the fact that generators would not be able to adjust their TEC capacity in response to a decision to implement WACM2 before 1st April 2016 is a valid reason to delay that implementation of WACM2. The implication from the latest consultation is that the Authority believes that this inability to respond means that there is no benefit to earlier implementation. We outline below that we neither consider that it is reasonable to assume that generators cannot take action without incurring penalties nor that there is no benefit to earlier implementation, prior to 1st April 2016, of WACM2.

It is important to introduce the proposed (CMP213) WACM2 change to the transmission charging methodology as early as possible because any effect of an increase in the forthcoming Capacity Mechanism costs would apply in full from the start of that mechanism, but the reduction in low carbon support cost will take time to take effect as additional low carbon capacity is added over time. It is therefore not surprising that the benefit, of WACM2, to customers takes time to build. Any delay, beyond 1st April 2015, in the implementation of WACM2 will further delay the realisation of the low carbon support benefits and the greater benefits to customers that could have been realised if WACM2 had been introduced earlier.

We note, in this regard, that the original implementation date of 1st April 2012 (as per Ofgem's numerous statements[57] in 2011) has 'slipped' a further two years in the space

[57] See, in particular, our response to the August 2013 consultation for the details of these numerous statements

of circa three months - from 1st April 2014 (pre 16th December 2013[58]) to 1st April 2015 (pre 14th March 2014[59]) to 1st April 2016 (post 14th March 2014).

There are several benefits to an earlier implementation date, as described below:

- **CfD power stations will be able to respond without penalty, so an earlier implementation could reduce customer costs** - CfD power stations participating in the first CfD competitive allocation round in Autumn 2014 to receive CfD contracts commencing 1st April 2015 would also have the opportunity to react to the earlier implementation, of CMP213, on 1st April 2015 by changing their strike price. These CfD contracted power stations would be able to reduce their bid prices in the CfD allocation round, which could result in a lower clearing price and a sustained lower cost to customers. This benefit was recognised by Baringa in their modelling of costs to customers and if the implementation date for CMP213 is delayed to 1st April 2016, then this first year of benefit to customers from reduced low carbon support costs would be lost.

- **Repeated delays and a failure to implement by 1st April 2015 could increase future hurdle rates** - Continued commitment by the Authority to their intention to implement quickly which until mid December 2013 was a "minded to" implement on 1st April 2014 (that had been extensively consulted on and well signalled to the market) could help ensure the policy environment remains predictable from the investors' perspective which could help to lower investment hurdle rates for new generation. In contrast, the change outlined in mid December 2013 to the previous 'minded to' position, to implementation on 1st April 2014, then the subsequent change, by the Authority, to being 'minded to' delay implementation to 1st April 2015, then subsequently to delay further to 1st April increases the perception of risk around the transmission charging regime, and hence increase future hurdle rates. Especially in the context of other policy changes which have been put into place within a much shorter timescale than CMP213, it could be a significant concern that any future proposals for market change may be delayed and drawn out far beyond the timescale initially intimated has been the case with CMP213. This would be perceived as a step change increase in policy risk, and would lead to an increase in the required hurdle rates for generation investment and ultimately to higher costs to customers.

- **Similarly such delay to well heralded policy change could be perceived as an increase in policy risk by suppliers, leading to an increase in future risk premiums in Supply tariffs, ultimately leading to increases in customer bills** – As above regarding generator hurdle rates, an early implementation of CMP213 would be perceived as in line with industry expectations regarding the expected impacts of policy risk. However, a delay to the implementation of CMP213 could be seen to undermine the consultation and implementation cycle for future policy changes which could result in an increase to future supply tariff risk premiums.

[58] https://www.ofgem.gov.uk/ofgem-publications/85131/projecttransmitupdateonprogressandnextsteps.pdf
[59] https://www.ofgem.gov.uk/ofgem-publications/86569/projecttransmitupdateonprogressandwayforward.pdf

(ii) Consumer Costs

We do not agree that there is a cost associated with earlier than 1st April 2016 implementation of WACM2 in terms of increased hurdle rates for future investment. We outline above that we consider there is a strong case that the reverse is true, that delay in the implementation date to 1st April 2016 will impose a cost.

Furthermore, we do not agree that implementation before 1st April 2016 could lead to suppliers including greater risk premia in their fixed cost tariffs nor that this could increase costs to consumers. We have also outlined above that we consider there is a strong case that the reverse is true, that delay in the implementation date to 1st April 2016 will impose a cost.

The Authority puts forward, in the consultation document, three mechanisms by which the implementation date for CMP213 could impact the cost to consumers, although our view is that these mechanisms would not increase customer costs.

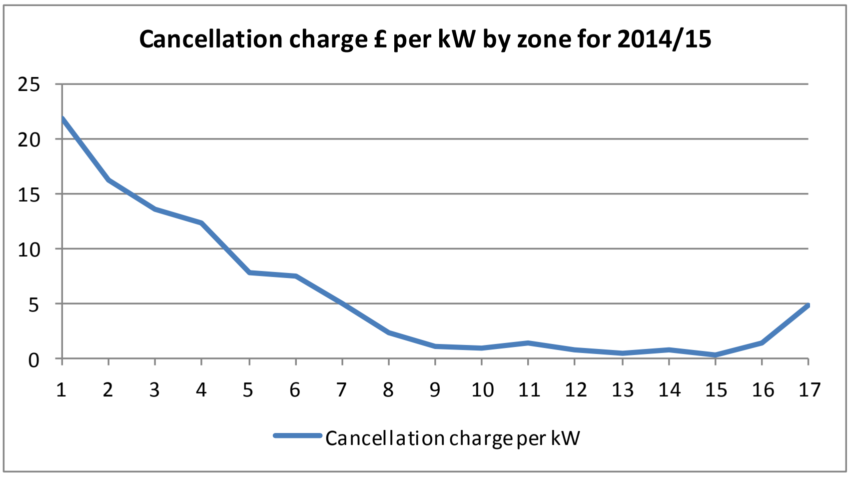
(a) Cost of generation if generators could not adjust their TEC capacity in response to early implementation of CMP213 (WACM2) without incurring penalties

It is possible, as suggested by the Authority, that the proposed change in TNUoS charges could make it economic for some generators to reduce their TEC and incur penalties in the process. Mitigating factors include:

- **Penalty charges would be small** – Penalty charges would only be an issue for generators who may see their TNUoS charges increase following the introduction of WACM2, which will tend to be generators in Southern zones. However, graph 1 below uses National Grid published data[60] to show that penalty charges for those same TNUoS charging zones are negligibly small at an average of only £1.05 per kW for cancellation charge zones 8 to 16. The only Southern zone with a significant penalty charge is zone 17, although even this is within the historic margin of error which generators accept and are accustomed to managing between National Grid’s announcement of final TNUoS tariffs and National Grids initial forecast one year before the start of the financial year to which the TNUoS charges apply.

[60] 2013/14 Wider Cancellation Charge Statement, Version 2, National Grid 7th January 2013

Graph 1



- **Penalty charges are not a cost to customers** - Any penalty payments made by generators would be offset against the residual, so would not represent a cost to customers.

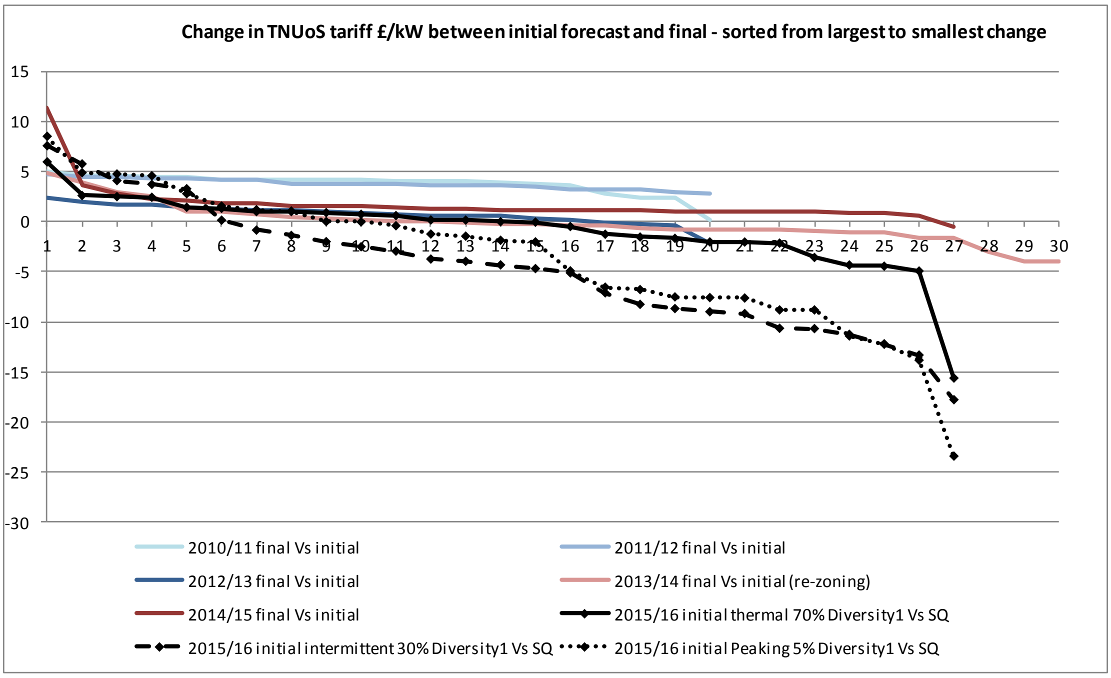
- **Net impact of late notice may be a reduced cost to customers** - The power stations likely to be most affected will tend to be those in negative zones receiving a subsidy from the TNUoS charging methodology. If these stations reduced their TEC at late notice after the final TNUoS tariffs had been announced, then they would not receive this subsidy payment for 2015/16, then this unpaid subsidy would tend to result in an over collection of TNUoS from generators in 2015/16, so representing a net reduction in cost to customers in the following year.

- **Reduced notice period** - It should not be necessary, but if a remedy was required, then this could include a one off (SCR directed modification specific) reduced notice period for power stations to adjust their TEC without incurring a penalty charge. In this respect we note the Authority's intention (in December 2013) to notify affected parties during March 2014 in time for them to submit their notice by 21st March 2014 (the year and five working day deadline this year to avoid a penalty charge). A similar approach could be applied to a reduced notice period.

- **Generators already face uncertainty regarding their final TNUoS charges and the switch to WACM2 is within that historic range.** The National Grid published initial forecast of TNUoS tariffs for 2015/16 showed that the expected increases in TNUoS charges of a conventional 70% load factor power station in the South under WACM2 would be within the historic margin of error between previous initial forecasts and final TNUoS tariffs which are also imposed within a year and do not provided an opportunity for generators to adjust their TNUoS without penalties (see graph 2, 3 and 4 below). There is no evidence to suggest that any TNUoS tariff increases following the introduction of WACM2 should be treated any differently from these historic variations.

Graph 2, shown below, shows changes in zonal tariffs between Final and Initial forecasts one year before the start of the charging year to which the TNUoS tariffs applied. This also shows the expected differences in charges between Diversity 1 and Status Quo for different technology types[61]. Please note the numbers shown are the rank of zones in order of largest increase to largest decrease and do not represent the names of the charging zones themselves. The data has been shown in this format so that historic changes can be compared over periods when there were 20 zones and 27 transmission charging zones. Graph 2 shows 30 ranked changes for 2013/14 due to the re-zoning which resulted in some new zones having more than one old zone as a comparator.

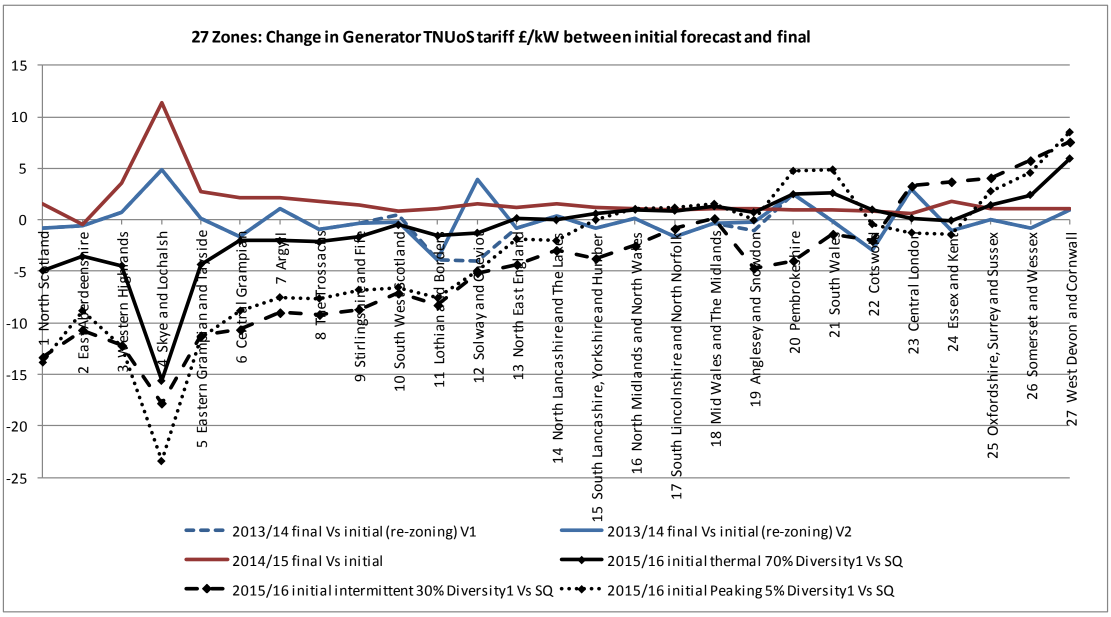
Graph 2



Graph 3, shown below, compares the historic changes between Final TNUoS tariffs and National Grid Initial forecasts one year before the start of the charging year to which the tariff applies, along with the expected differences in charges between Diversity 1 and Status Quo for different technology types. This is shown for 27 zones from 2013/14.

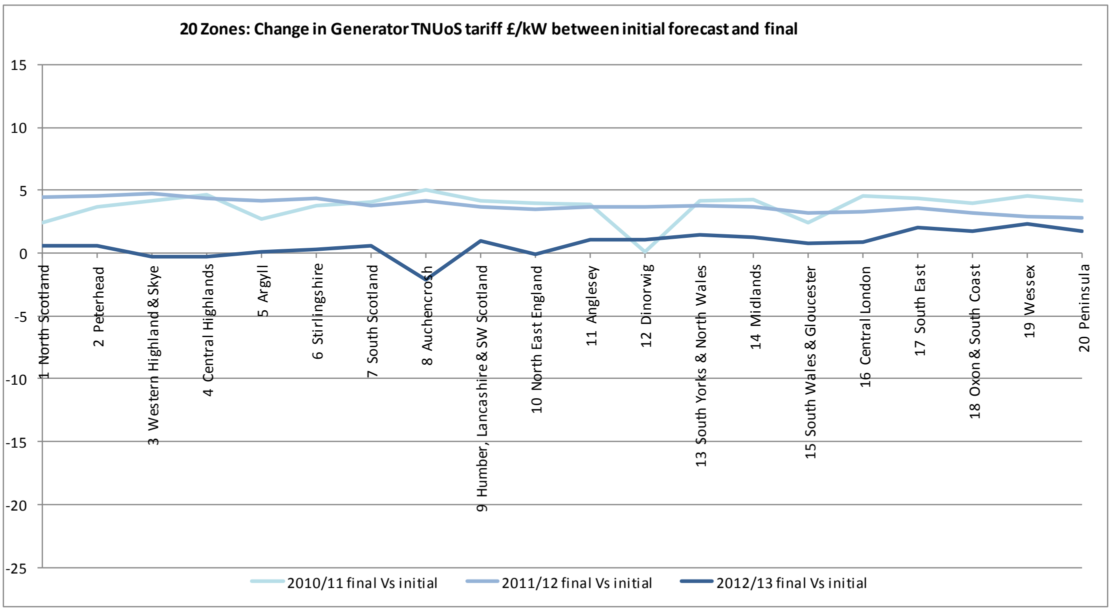
[61] National Grid Initial View of Use of System (TNUoS) Tariffs from 2014-15 to 2018-19, Section 3, May 2014

Graph 3



Graph 4, shown below, compares the historic changes between Final TNUoS tariffs and National Grid Initial forecasts one year before the start of the charging year to which the tariff applies. This is shown for 20 zones from 2010/11 to 2012/13. The expected change following the introduction of WACM2 is not shown on this graph because the forecast tariff data published by National Grid was for 27 zones which are not directly comparable. However it is possible to compare the historic changes which included many zones showing increases for approximately £5 per kW with the graph above which shows all technologies for almost all zones demonstrating increases of less than £5 per kW.

Graph 4



(b) Hurdle rates for future investment may change based on perception of future policy uncertainty

An earlier implementation of WACM2 than 1st April 2016 would not cause developers to increase their hurdle rates because of the reasons outlined below:

- **There is a relatively small risk to generators following the introduction of WACM2 at an earlier date** – As illustrated in graph 4 shown above, the expected increases in TNUoS tariffs for some generation technologies in some zones[62] is within the range of historic uncertainty between Final zonal tariffs and Initial National Grid forecasts one year before the start of the charging year to which it applies. This change is expected and well understood by generators, but even if it was not, then the impact is within the range of the uncertainty regarding TNUoS charges which generators already accept and are accustomed to dealing with.

- **Perceived policy risk is already factored into hurdle rates and this perception of risk will not be increased by an earlier implementation** – A number of recent studies have provided evidence that policy risk is an important factor affecting hurdle rates. [63] This means that hurdle rates already account for the expectation that policies are likely to change, so this is already taken into account in investment decisions. If WACM2 was introduced earlier, than the now 'minded to' date of 1st April 2016, then this would be within the expected range of policy uncertainty which is already taken account of within existing hurdle rates. The Project TransmiT / CMP213 change to the charging methodology has been known to market participants for some time, and would

[62] National Grid Initial View of Use of System (TNUoS) Tariffs from 2014-15 to 2018-19, Section 3, May 2014
[63] See, for example, the survey evidence presented in Oxera (2011), 'Discount rates for low-carbon and renewable generation technologies', April.

already have been factored into investors' expectations of the financial attractiveness of future investments, especially given that the initial Ofgem stated position[64] was to implement four years earlier, on 1st April 2012, and the Authority's original minded to position was to introduce the change two years earlier on 1st April 2014. As described above, a wide range of different GB industry code changes, charging methodology changes, tariff changes and other policy changes have occurred at even shorter notice, so this is part of the normal and expected operating practice of the generation market. The only mechanism by which this particular decision for an earlier implementation date could increase hurdle rates would be if it signalled a step change towards future policy risk being greater than historic policy risk, but there is no evidence to suggest this could be the case. Prior to the publication of the Authority's letter in March 2014 parties were expecting the implementation date to be 1st April 2015.

- **One year earlier change to TNUoS methodology would be relatively insignificant compared with other risks** - When set against other risks that affect the business case for future generation, such as wholesale market price risk, construction cost risk, a revision in the timing of a change to a relatively small part of the overall cost base of new power plant would unlikely have a material impact on investors' required returns especially as this change (from 1st April 2015 to 1st April 2016) was only notified to the market in March this year.

(c) Suppliers may change the risk premia built into their fixed tariffs if they do not have sufficient time to plan for changes in transmission charges.

It is reasonable for suppliers to apply a risk premium to customer bills to take account of the many risks faced by suppliers regarding the future costs of procuring and delivering energy to customers. However, an earlier implementation of WACM2 than 1st April 2016 would not cause suppliers to increase their risk premiums because of the reasons outlined below:

- **The contribution of TNUoS charges to the customer risk premium is relatively small -** The size of supplier risk premiums are likely to be driven mainly by expected volatility in the wholesale power price, while TNUoS costs account for a very small proportion of the bill.[65]

- **The expected change in supplier costs is within the range of historic changes between National Grid initial and final tariffs** – An earlier implementation would have minimal impact on supply TNUoS rates**.** The change in supply TNUoS, if WACM2 were implemented on 1st April 2015, would be well within the expectations of existing risk premia, so would not result in any increase in future supply risk premia, (see graph 5 below). National Grid's initial forecast of 2015/16 tariffs under both WACM2 and Status Quo showed that the expected impact on demand TNUoS tariffs is insignificant in all but two charging zones, so even if TNUoS was a significant contributor to risk premium, the expected risk from the change to the charging methodology is in most cases insignificant.

[64] This is set out in detail in our response to the previous (August 2013) consultation
[65] See, for example, Ofgem (2013), 'Updated Household energy bills explained', February. As at December 2012, transmission charges represented around 4% of the average consumer's electricity bill.

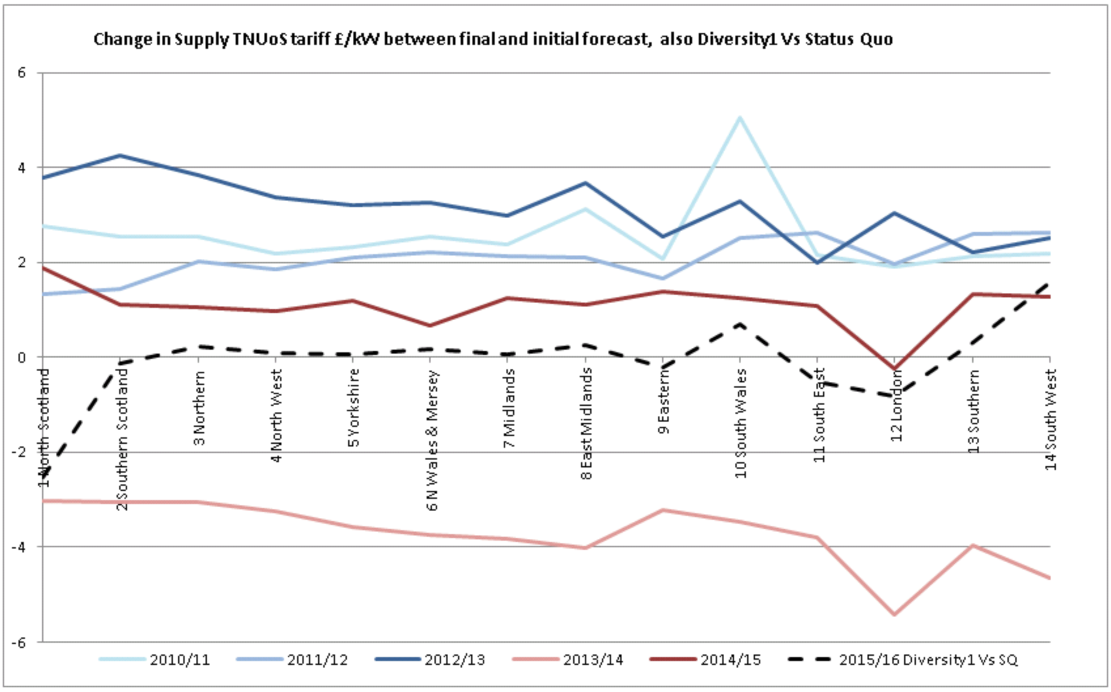
- **Only two small zones show any significant change in supply tariffs** - Only two zones (zone 1 and 14) demonstrated any significant change following the switch from Status Quo to WACM2 (one increase and one decrease) and as the graph shows, even these are within the historic range of variations in supply tariffs which could be expected between National Grid published initial forecasts and final tariffs. The only zone showing any significant increase represents a very small proportion at 5% of total demand (For 2015-16, Zone 14 shows 2,922 GW out of a total of 55,574 GW).[66]

- **There would be insignificant pass though from generator TNUoS and wholesale costs –** TNUoS represents a fixed cost to generators based on their TEC, so an earlier implementation of WACM2 (from 1st April 2016 to 1st April 2016) is unlikely to impact the marginal cost component of the wholesale price. As suggested by Baringa[67], if the ALF component did feed though to the wholesale price through generator marginal costs, then the subsequent impact on changes to merit order, and hence a reduction in constraint costs, would likely result in a net benefit to customers. It is possible that a change to the charging regime could encourage generation plant to adjust their TEC, and hence result in a change to system plant margin. However, this impact could go either way, especially since the increase in TNUoS costs to northern generators of choosing the Status Quo for 2015/16 would be so much larger than relatively small increase in TNUoS costs to southern generators from introducing WACM2.

Graph 5, shown below, illustrates the difference between the Final half hourly TNUoS supply tariffs and the Initial tariffs published by National Grid one year before the start of the charging year to which the tariffs will apply. The graph also shows the difference in half hourly TNUoS supply tariffs as shown in the National Grid 13th May 2014 publication of its "Initial View of Network Use of System (TNUoS) tariffs from 2014-15 to 2018-19", Section 3[68].

[66] Initial View of Network Use of System (TNUoS) tariffs from 2014-15 to 2018-19, Appendix E : Zonal Summaries of Modelled Demand, Table 46, National Grid, 13th May 2014
[67] Baringa, 25th April 2014 page 83
[68] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

Graph 5



The recent EBSCR final decision document from the Authority indicates that the reform will being about an increase in the wholesale posts in 2016. This however has not lead to a decision, by the Authority, to direct that the implementation be delayed. The Authority stated in the same decision document that "*The bill impacts also do not account for any changes in supplier risk premiums or for any impacts on competition. However, our analysis has shown there are unlikely to be any significant impacts in these areas.*" [69] The expected changes in wholesale prices arising from WACM2 are much smaller than those expected to arise from the EBSCR directed changes. Thus it seems inconsistent to delay the implementation of WACM2 (to 1st April 2016) whilst not delaying the implementation of the two EBSCR directed Modifications.

<u>(iii) Precedent</u>

In our view the evidence provided in (a) the letters of 16th December 2013 and 14th March 2014 and (b) the latest consultation of 25th April 2014 to support these two substantial changes have been limited; and this is especially the case with respect to the latest slippage (from 2015 to 2016) as the reasoning (plus supporting evidence) is lacking from this latest consultation document.

We are mindful that the Authority embarked upon Project Transmit on 22 September 2010[70]. Since then there have been a series of changes to TNUoS and other charges incurred by generators and suppliers (such as BSUoS) which have been implemented within a charging / calendar year. It is inconsistent that the Authority are "minded to" delay implementation from what was the "minded to" position in December 2013 especially given that the basis for such delay has not been substantiated with evidence

[69] Ofgem, 15th May 2014, para 3.37

[70] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-call-evidence

or quantified. As outlined above we do not agree that such a delay will have no impact on delivering the positive aspects of Project Transmit. We have also outlined above that we do not agree that implementation before April 2016 will result in negative long term impacts on customers.

However, this proposed implementation approach for CMP213 is not only inconsistent with what the Authority has done with respect to recent similar changes but also it appears to be manifestly inconsistent with what the Authority is now proposing to do with respect to the forthcoming Electricity Balancing SCR[71] directed first modification that would see the PAR value halved from '500MWh' to '250 MWh' in time for this coming November.

We explore the precedence established by the Authority for early implementation for both previous charging changes and future changes (vis the Electricity Balancing SCR directed changes) further below.

We note that the current notification period[72] for changes to TNUoS is, according to the Transmission Licence, 150 days in advance for indicative charges and one month in advance for the final charges, whilst the industry code sets the notification period as two months in advance. These licence obligations seem significantly at odds with the position now being taken by the Authority.

In terms of the impact on suppliers and the need '*to avoid them building risk premiums in future for fixed tariff offers to consumers*' we note that is has proved extremely difficult for any supplier (or other stakeholders) to quantify the approximate, let alone actual, volume (either in terms of overall customer numbers and / or MWh etc.,) that suppliers have on fixed tariffs. We are also mindful that this 'reason' has been used by a number of suppliers in respect of CMP201 and, more recently, in the CMP224/CMP227 deliberations to seek to have three, four and even five years 'notification' of changes, even though the forward curve liquidity shows no volume beyond winter 2016 and small volumes in the winter 2016 and summer 2016 time periods according to EnergyUK latest analysis[73].

In putting forward the suggestion that its '*important to give suppliers sufficient lead time ahead of implementation to avoid them building risk premiums in future for fixed tariff offers to consumers*' there is a very real danger that the Authority is seriously interfering with the market place by actively dis-incentivising suppliers from managing any of their own risks. Suppliers who have chosen to provide fixed tariff offers to customers are, it would appear with this 'minded to' position of the Authority, now to be protected from the commercial impact of the decision they freely took to make those offerings in the market place.

In this respect it should also be noted, as set out in Section 14.28 of the CUSC[74] (the charging methodology section of the CUSC) that with respect to the stability and predictability of TNUoS charges that the "*...Charging Methodology has a number of*

[71] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review
[72] Ofgem 17th October 2012, Table 2.2 page 16
[73] http://www.energy-uk.org.uk/publication/finish/5-research-and-reports/1103-wholesale-market-report-may-2014.html
[74] http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/the-cusc/

elements to enhance the stability of the tariffs, which is an important aspect of facilitating competition in the generation and supply of electricity" [75] and these elements are highlighted in that part of the CUSC.

In addition to these elements National Grid facilitate competition in supply (and generation) by providing users with tools and information to help with the users' long term planning, as noted in Section 14.28 of the CUSC:

> "*More fundamentally, The Company [National Grid] also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis*." [76]

Notwithstanding this wealth of information provided to suppliers (and generators) by National Grid they also provide updated forecasts, to suppliers (and generators), of TNUoS charges four times a year for the following charging year as well as an annual five year TNUoS forecast.

Furthermore, it should be noted that transmission charges make up circa 4% of a customers bill and this WACM2 change will see, in the short term, no additional transmission assets built over and above that already contracted (as it take more than two years to build new capacity and get it into the MAR) so thus it should have no meaningful impact on any suppliers' charges – indeed there is a strong suggestion that suppliers will see no appreciable effect on their charges from WACM2 in the medium and long terms. Conversely the wholesale energy costs make up the majority of a customers' bill and, as noted above, the latest EnergyUK analysis shows no forward curve liquidity beyond winter 2016 (and little volume in the immediate period before this) – suppliers are fully exposed to this situation.

We would also like, in particular, to highlight the following five inconsistencies with other Authority decisions made during the Project Transmit period.

(a) 22 September 2010 Project Transmit commences

The Authority issued its 'call for evidence' consultation[77] that began the Project Transmit / CMP213 process of which this consultation is the latest incarnation in September 2010.

(b) 1st October 2010 Mid-year update to TNUoS tariffs

Following the Authority's approval[78], during the 2010/11 charging year, of GB ECM21 this meant that generators and suppliers had missed the opportunity to submit a notice to avoid these charges (by giving notice some three weeks earlier by mid

[75] CUSC Section 14 V1.6 –12th March 2014, Page 93 of 116
[76] http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/the-cusc/
[77] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-call-evidence
[78] of GB ECM21 on 9th April 2010, implemented on the same day.

March 2010). Later that charging year, on 1st October 2010, National Grid notified TNUoS parties that the TNUoS charges for the 2010/11 charging year were to be changed, 'mid year', from 1st December 2010.

It is interesting to note the views of National Grid set out in their Conclusions Report to the Authority on GB ECM-21[79] when considering the responses of stakeholders, such as suppliers, to the proposed 'mid year' TNUoS change.

They noted that they, National Grid, were "*...unconvinced that users would be unable to respond to the cost signals that option 3 would give. All industry participants already react to costs that are changing year on year, for example BSUoS costs change continually and the industry factor in the risk of this cost change. However National Grid recognise that the industry would like as much clarity and prior warning of changing costs and will endeavour to supply information to this effect. Suppliers routinely change tariffs to consumers, for example between May and October 2009 suppliers changed their tariffs 39 times, and therefore National Grid is unconvinced that suppliers would be unable to respond to the tariff changes if they wanted to*."

We agree with these comments by National Grid. We note that the National Grid analysis of the large number of times that suppliers changing their tariffs to customers was not confined to 2009 but extended into 2010 (this is illustrated by the data from 'SimplySwitch' who tracked all the gas and electricity price changes in the UK energy market for 2010[80]) when suppliers continued to changes their tariffs numerous times.

(c) 4th October 2010 GB ECM-26: "Review of interconnector charging arrangements[81]"

The Authority approved a retrospective change to TNUoS charges for generators which, if you accept the arguments put forward by those who argue against CMP213, would have an effect on charges for suppliers as well.

The Authority GB ECM-26 decision letter noted:-

> *"We acknowledge the views of some respondents that the proposals should not be applied to tariffs within the current charging year. However, for the reasons set out below, we consider that the application of the revised tariffs to the entire tariff year are appropriate."*
>
> *"We are of the opinion that, when taken together, there are reasonable grounds that warrant the retrospective application of the proposed charging changes to the charging year from 1 April 2010 to 31 March 2011."*

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[79] http://www.nationalgrid.com/NR/rdonlyres/0129372D-E96D-4B0B-9E0F-A564705995DD/40216/GBECM21ConclusionsreportFinal.pdf

[80] http://www.simplyswitch.com/home/energy-price-rise-table

[81] http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Historical-Use-of-System-charges-consultations/

This retrospective change was approved by the Authority on 4th October 2010 and applied to TNUoS charges from 1st April 2010 – over halfway through the charging year.

(d) 15th August 2012 CMP202 – Removal of BSUoS charges from Interconnectors

In mid August 2012 the Authority approved CMP202[82] which was designed to remove BSUoS charges form users of the interconnector.

The Authority's decision letter noted:-

> *"...NGET estimated that interconnectors currently contribute 2.1% of the total BSUoS charges which would be reallocated to other CUSC parties as a result of this modification."*

Whilst there were benefits from implementing CMP202 (as there are with CMP213) we cannot see how these benefits were realised within ten working days (which was the implementation period for CMP202). This meant that parties, both generators and suppliers, did experience an actual detrimental impact (from the approval of CMP202) in the short term – yet this did not prevent or impede the Authority setting a ten working day implementation period.

(e) 15th May 2014 Electricity Balancing SCR Final Decision

Whilst not a change to the charging arrangements (as (a) to (d) are) during the course of this latest CMP213 consultation the Authority issued a direction[83] to National Grid to bring forward a (BSC) modification to:-

> *".....make cash-out prices more marginal, specifically, we consider it is important for the Price Average Reference volume as defined in the BSC (PAR volume) to be lowered to 250MWH [from 500 MWh] by early winter 2014/15"*

The effect of this halving of the PAR volume is designed to have a material impact on market prices – hence why the Authority is seeking this change being brought in for this coming winter.

Although the actual implementation date for this directed modification has still to be determined it is clear that the Authority, by making its decision (vis the Electricity Balancing SCR) to issue a direction, has already led to an increase in market prices for this coming winter (and beyond) from mid May as the forward market reacts to the directed change.

However, BSC parties (such as suppliers) will have had limited time to react to this change in market prices – and yet this has not prevented the Authority directing that this change be brought forward, for this coming winter.

[82] http://www.nationalgrid.com/NR/rdonlyres/A12AC378-A737-423E-BD0B-F66AD644C0A2/55821/CMP202D.PDF
[83] https://www.ofgem.gov.uk/publications-and-updates/direction-national-grid-electricity-transmission-plc-relation-electricity-balancing-significant-code-review

It also raises a related question; namely how is it consistent that one SCR change (for electricity balancing) can be implemented within six months of an Authority direction (which includes the time needed for a modification to be raised, assessed, and industry consulted – twice) whilst with another SCR (namely CMP213) the implementation date is to be some four years after the direction was issued[84] of which circa 18 months will be from the period between a final Authority decision (to approve) and the actual date of implementation?

We are not the only party to recognise that changes to TNUoS charges can occur out with a '1st April' timeframe.

This was highlighted in the Authority's 17th October 2012 'Decision in relation to measures to mitigate network charging volatility arising from the price control settlement'[85] which noted that:

> "*Responses [to the Authority's consultation] indicated that in the last five years across all sectors there have been changes to charges outside of 1 April. The materiality and frequency of these changes has been varied. The reasons stated for these changes were mixed but generally they were to update forecast position and therefore avoid the over or under recovery penalty by the end of the year,* ***or for changes in the charging methodologies*** [emphasis added]"[86].

These respondents views were clearly persuasive because we note that the Authority went on to indicate in their decision that whilst a '1st April' was preferred that

> "*We consider that in all sectors there is benefit in allowing for exemptions to this requirement. We intend to include provision, within the licence, for the Authority to allow for changes outside of 1 April if NWOs can provide reason why it would be beneficial. For example, it may be necessary for a DNO or GDN to change its charges as a result of the supplier of last resort requirement,* ***for important changes to the charging methodologies*** [emphasis added] *or to correct for material charging errors*."[87]

It is clear that when the Authority established the Significant Code Review process that they considered such a process would be 'reserved' for important changes. As Ofgem's "Guidance on the launch and conduct of Significant Code Reviews (SCRs)"[88] noted with respect to when an SCR would be undertaken that it would be when:

> *"the Authority considers those issues are* ***significant*** *in relation to its principal objective and/or its other statutory duties and functions, or due to obligations arising under EU law, in particular –*

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[84] 25th May 2012
[85] https://www.ofgem.gov.uk/ofgem-publications/50572/cvdecision.pdf
[86] Ofgem, 17th October 2012 para 2.34
[87] Ofgem, 17th October 2012 para 2.43
[88] https://www.ofgem.gov.uk/ofgem-publications/61740/guidanceintiating-and-conducting-scrsfinal-draft110810.pdf

> *...there is likely to be significant impacts on **gas and electricity consumers** or **competition** (based on a qualitative assessment); ...”*

In our view the Project TransmiT SCR is clearly an important change to the charging methodology and thus the Authority is well within its rights to implement this WACM2 change, to the charging methodology, out with the ‘1st April’ timeframe. If CMP213 (WACM2) is not considered ‘important’ then it does beg the obvious question what change(s) to the charging methodology exactly, if not Project Transmit, is considered ‘important’?

Annex 2

We have commissioned a review, by Oxera, of the NERA-Imperial College London report "Assessing the Cost Reflectivity of Alternative TNUoS Methodologies" that was prepared for RWE npower (dated 21st February 2014).

The Oxera review, dated 27th May 2014, forms part of our consultation response as this Annex 2.

We have drawn from the Oxera review in the body of our response to the consultation.

Annex 3

We have commissioned a critique, by Phil Baker, of the NERA-Imperial College London report “Assessing the Cost Reflectivity of Alternative TNUoS Methodologies” that was prepared for RWE npower (dated 21st February 2014).

The Baker critique, dated 27th May 2014, forms part of our consultation response as this Annex 3.

We have drawn from the Baker critique in the body of our response to the consultation