# CMP213: further analysis and review of consultation responses

Further analysis of CMP213 options, and review of NERA/ICL and Pöyry responses to CMP213 Consultation for Ofgem

***Version History***

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# Executive Summary

Project TransmiT is Ofgem's review of electricity transmission charging arrangements.  As part of the Significant Code Review (SCR) under Project TransmiT, Ofgem commissioned Redpoint Energy (now part of Baringa Partners LLP) to model the impacts of the transmission charging options being considered. The results of our study were published in December 2011[1] alongside Ofgem's consultation document[2].

The conclusion of Ofgem's SCR[3] on Project TransmiT included a direction for the Connection and Use of System Code (CUSC) Panel to develop a modification to the CUSC (CMP213) based on the Improved Investment Cost Related Pricing (ICRP) approach, which would recognise the dual drivers of transmission investment namely a year-round component (reflecting the output patterns of renewables) as well as the established peak demand security driver.  National Grid undertook further analysis and modelling in the Transmission Decision Model (TDM) which was developed by Redpoint in conjunction with National Grid and Ofgem under the SCR, to assess proposals developed under CMP213.  In Summer 2013, Ofgem commissioned Redpoint to perform a review of this analysis[4].  This was published alongside Ofgem's Impact Assessment[5] in August 2013, which announced a minded-to position to approve the option known as "Workgroup Alternative Connection and Use of System Code (CUSC) Modification 2 (WACM2)".  The consultation on the Impact Assessment closed in October 2013.

Through the consultation process on its minded-to position, Ofgem received a wide range of feedback including a number of challenges to its conclusions and the underlying analysis supporting these conclusions.  The most extensive responses were provided by RWE npower and Centrica, with supporting reports respectively from NERA/Imperial College London and Pöyry.

Ofgem commissioned Redpoint Energy to review these consultant reports to assess the validity of the arguments raised and to understand the differences between the analysis presented in these reports and the work undertaken by National Grid in support of the CMP213 Impact Assessment. We were also asked by Ofgem to update the Impact Assessment modelling to address comments received through the consultation phase, and to take into account the latest policy positions on Electricity Market Reform (EMR) which have evolved considerably since the original analysis was undertaken.

[1] Modelling the impact of transmission charging options – A report by Redpoint Energy, December 2011.  Available at: http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

[2] https://www.ofgem.gov.uk/ofgem-publications/54124/project-transmit-dec11.pdf

[3] https://www.ofgem.gov.uk/ofgem-publications/54066/transmit-scr-conclusion-document.pdf

[4] https://www.ofgem.gov.uk/ofgem-publications/82377/cmp-213-modelling-review-cmp213-impact-assessment-modelling-ofgem-redpoint-energy.pdf

[5] https://www.ofgem.gov.uk/ofgem-publications/82538/projecttransmitimpactassessmentofcmp213options.pdf

***Key issues raised by NERA and Pöyry***

Both the NERA/ICL and Pöyry reports raised issues relating to the principles underpinning the WACM2 approach. The reports suggest that the WACM2 methodology does not reflect the transmission investment principles as set out by the Security and Quality of Supply Standard (SQSS). Specifically, the reports argue that the WACM2 year round background does not match the economy criterion in the SQSS. However, the economy criterion reflects a pseudo-CBA approach which is a proxy for a full CBA (which would be used for larger transmission investments). 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.

Both the Pöyry report and the NERA/ICL review claim that the Impact Assessment does not provide sufficient evidence that the WACM2 approach is more cost reflective than Status Quo, and it is true that there is no direct comparison of the incremental transmission costs related to different generation types in different locations and the transmission charges that they face in the Impact Assessment consultation. NERA/ICL have conducted useful analysis using ICL's Dynamic Transmission Investment Model (DTIM)[6] model which compares the expansion cost of the marginal investment (the Long Run Marginal Cost, or LRMC) to a set of Status Quo and WACM2 tariffs calculated in the DTIM model.

The ICRP methodology on which both Status Quo and WACM2 are based reflects average incremental, expansion costs[7] (based on load flow modelling across available transmission assets). The differences in ICRP tariffs will typically turn out to be a close match to the relative LRMC where the variation in marginal investment cost fluctuates around a mean trend over a sustained period of time. Where this is not the case, the tariffs produced by the ICRP methodology may not be as close a match to the relative LRMCs of new investment.

Both the Status Quo ICRP methodology and the WACM2 variant are approximate representations of the drivers of transmission costs. What the NERA/ICL cost reflectivity analysis suggests is that in the specific case of onshore wind where the incremental transmission expansion is facilitated by bootstrap HVDC technology, the modelled version of the Status Quo approach is slightly more reflective of the marginal transmission expansion costs than the WACM2 methodology. However, in circumstances where HVDC reinforcement is not the method by which incremental transmission network capacity is provided to accommodate onshore wind , and for most other generation technologies, the WACM2 methodology is generally somewhat more cost reflective than the Status Quo methodology. This result is consistent with analysis conducted by National Grid on the drivers of constraint costs (and hence the need for transmission reinforcement) undertaken for the CMP213 Impact Assessment. The NERA/ICL cost reflectively analysis is useful in illustrating the complicating factor caused by the incorporation of HVDC technology, and illustrating the imperfections in any transmission charging methodology.

[6] DTIM is an optimisation tool which aims to minimise the overall cost of constraints and network reinforcement works. It considers multiple boundaries and multiple years, to derive the optimal amount of transmission expansion at each boundary in each epoch modelled (assuming each boundary can be linearly expanded).

[7] The methodology is based on linear expansion of existing transmission assets (in the proportions required to accommodate a marginal MW of generation or demand) and removes the 'lumpiness' associated with transmission investments by decoupling charges from the actual investments made.

*Review of NERA/ICL quantitative analysis*

As part of RWE npower's consultation response, in addition to the cost reflectivity analysis, NERA/ICL undertook an independent impact assessment of the WACM2 methodology. Further details of this were provided to Ofgem through supplementary information requests. In summary, their analysis suggests a significant dis-benefit of WACM2 relative to Status Quo. This is in contrast to the results from the National Grid modelling, particularly by the fact the NERA/ICL analysis suggests increases in transmission ***and*** generation costs under WACM2.

**Table 1 NERA/ICL CBA results**

| | 2014-2020 | 2021-2030 | Total |
|---|---|---|---|
| **Impact on Consumers** | | | |
| Power Purchase Costs | 1,484 | 233 | 1,717 |
| Low Carbon Subsidies | | | 269 |
| D-TNUoS | 412 | 357 | 769 |
| Constraints | -49 | -14 | -63 |
| Losses | 268 | 418 | 687 |
| Total | 2,936 | 3,026 | 3,379 |
| | | | |
| **Power Sector Costs** | | | |
| Generation Costs | 1,157 | 2,985 | 4,142 |
| Transmission Investment | 501 | 420 | 922 |
| Constraints | -49 | -14 | -63 |
| Losses | 268 | 418 | 687 |
| Total | 1,877 | 3,810 | 5,688 |

Source: NERA/ICL

We believe that this result is counter-intuitive. Most expectations of modelling in this area would be that the impact of WACM2 would be to reduce generation costs and increase transmission costs (since WACM2 reduces transmission charges in Scotland, bringing forward generally higher load factor wind but requiring additional transmission capacity). If the reduction of generation costs is less than the increase in transmission cost this would suggest that WACM2 was less cost reflective, and vice versa.

The major driver of the higher generation costs originates in the amount, location and timing of onshore and offshore wind deployment. We have reviewed the NERA/ICL methodology for renewables investment based on information provided. Wind build is controlled by the level of renewable subsidies, limited by constraints on the rate of wind deployment (annually across GB and by zone).

We understand that NERA/ICL's renewables subsidy model optimises the level of onshore and offshore wind subsidies to meet the 2020 renewable electricity target at lowest subsidy cost to consumers, by testing subsidy levels at intervals of about £6.5/MWh for onshore wind and about £8.5/MWh for offshore wind. The results show that under WACM2, lower load factor onshore and offshore wind is built, therefore requiring additional capacity to be built to meet the 2020 renewable target. This capacity is also located such that it increases transmission costs and transmission losses. Whilst the increase in transmission costs is expected (and is consistent with the National Grid modelling), most observers would suggest that the average load factor of wind built would be higher with more build in Scotland.

In attempting to find a rationale for this effect, we have identified that under WACM2 the lowest cost projects (Scottish Highlands onshore wind with a load factor of 46.9%) are not built in the NERA/ICL modelling. These are assumed to have a levelised cost of £54.4/MWh under WACM2, lower than the level of £56.3/MWh under Status Quo, and significantly lower than the next onshore or offshore project.

NERA/ICL have offered the following explanation for this effect:

*[…] "Such results may be down to:*

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

*Given the complexity of the model, it is not possible to observe precisely which of these effects is driving the result. Also, when interpreting the tables and charts showing levelised cost data, it is important to consider that they are simplified, static representations of the costs fed into the model (see above). In particular, the measure of TNUoS shown on the chart is averaged over a number of years, so the data shown provide an approximate measure of the costs actually incurred by generators in our models.*[8]

Ofgem requested further details from NERA/ICL on which constraints are binding, but NERA/ICL did not provide this information. In the absence of additional information, we are not able to validate the reasons for this counterintuitive result. In our view, it is not a credible result that under a charging option which reduces TNUoS for onshore wind, the cheapest projects are no longer developed, particularly under the current proposals for allocating Contracts for Differences (CfDs) through competitive auctioning for established technologies. Furthermore, we no longer believe that transmission charging will materially affect the proportions of onshore and offshore wind built since CfDs will be allocated through separate funds for established and emerging technologies. Hence, suggesting that WACM2 will increase costs by bringing on more offshore wind at the expense of onshore wind is not valid. Because of the limitations in the assumed approach for allocating subsidies in the NERA/ICL analysis, and the counter-intuitive results it produces, we do not believe that its alternative impact assessment modelling can be relied upon.

***Further analysis of costs and benefits of WACM2 relative to Status Quo***

Although we have significant reservations about the independent impact assessment modelling undertaken by NERA/ICL, their report and that which was produced by Pöyry, together with other consultation respondents, raised a number of relevant issues relating to the analysis carried out for Ofgem's Impact Assessment. These include:

- The impact of the higher level of renewable generation in Status Quo compared to WACM2;
- The impact of volatile capacity margins on wholesale prices;
- Possible distortions to generation dispatch from the historic Annual Load Factor element of WACM2 tariff calculation;
- The impact of the low carbon generation mix; and

[8] NERA/ICL, Sixth Response to Ofgem TransmiT Questions

- The need for additional sensitivity analysis.

We have further enhanced the TDM based on latest EMR design positions and performed further analysis which aims to address these issues. We now model CfDs as being competitively allocated by technology type. This ensures that the cheapest projects are developed and eliminates cost differences in the modelling resulting from different levels and mixes of renewables. This enhancement helps to isolate the impact of transmission charging changes from other effects that can affect the results. The Capacity Market is now fully captured as a market based on capacity auctions to maintain a de-rated capacity margin of 10%[9]. This has helped to eliminate differences in consumer costs resulting from volatility in wholesale prices driven by variability in capacity margins, again making comparisons between cases much clearer. In addition, we assume generators cannot respond to WACM2 tariffs before 2015.

We have modelled an Original Case in the enhanced model, using the assumptions from the analysis for Ofgem's Impact Assessment, and an Alternative Case. The key assumptions are shown in Table 2.

**Table 2 Differences in assumptions between Original and Alternative Case**

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

Our analysis suggests that under WACM2, there is a shift in development of onshore and offshore wind capacity northwards. This decreases generation costs due to the higher assumed load factors of onshore wind in Scotland relative to England and Wales, but increases the sum of transmission and constraint costs.

[9] It is important to note that these de-rating factors differ from those used by Ofgem for its Capacity Assessment (CA) in 2013. The margin of 10% used is roughly equivalent to a 2015/16 derated margin of 4% using Ofgem CA 2013 de-rating factors, and a Loss Of Load Expectation of 3 hours per year (consistent with the reliability standard that DECC is proposing to assess the capacity requirement). We note that Ofgem's CA 2013 demonstrates that the margin required to achieve a specific reliability standard may change over time with changing capacity mixes.

[10] Nuclear and CCS levels in the Original Case were developed by the CMP213 working group. In the updated modelling the timing and location of Nuclear and CCS is exogenous to the model. In the Alternative Case, a greater proportion of renewables was assumed after 2020 by broadly following the DECC UEP onshore and offshore wind deployment assumptions to 2030, with correspondingly less CCS and nuclear to achieve a similar power sector carbon intensity of around 100 g/kWh by 2030.

Under WACM2, new thermal generation capacity may be located further north (as gas exit charges become a more important locational driver), and retirements may occur more rapidly for plant in the south. This has the impact of increasing transmission costs under WACM2.

Table 3 shows the updated Cost Benefit Analysis. Overall, the change in power sector costs under WACM2 is a small dis-benefit in the period to 2020 under both the Original Case (-£115m) and the Alternative Case (-£31m). After 2020, both cases demonstrate a net benefit, of £184m and £99m respectively. These differences are much smaller than in the National Grid modelling for Ofgem's Impact Assessment, reflecting the fact that differences in renewables build have been eliminated with the enhanced modelling approach. These cost differences are now entirely related to the location of plant on the system.

The changes in consumer costs relative to the underlying changes in power sector costs are driven by two offsetting effects. Under WACM2, the levelised cost of the marginal CfD strike price setting onshore wind and offshore wind plant reduces, which creates a saving for consumers. On the other hand, the typically higher charges faced by the marginal thermal capacity in the Capacity Market (an effect correctly identified in the NERA/ICL report) increase costs for consumers. The net result depends on the marginal impact on prices, and the volumes of capacity which are exposed to the changing price.

Under the Original Case assumptions, the Capacity Market effect outweighs the CfD effect (due mainly to a larger volume of capacity receiving CM payments than CfD payments), leading to a net cost to consumers of -115m up to 2020, and -£884m between 2021-2030, despite the lower power sector costs. Under the Alternative Case assumptions, overall CM payments are lower (since less GB capacity is required to meet the capacity requirement) and the difference between Status Quo and WACM2 capacity price is reduced since the auctions are typically clearing on plant which are less affected by the changing transmission charges. Overall, there is a small disbenefit to consumers in the 2011-2020 period and a small benefit to consumers in the 2021-2030 period, reflective of the underlying changes in power sector costs.

**Table 3 Cost Benefit Analysis**[11]

| WACM2 benefit relative to Status Quo NPV (£m) | | Original Case | | Alternative Case | |
|---|---|---|---|---|---|
| | | 2011-20 | 2021-30 | 2011-20 | 2021-30 |
| **Power sector costs** | Generation costs | 18 | 607 | 19 | 103 |
| | Transmission costs | -38 | -169 | 0 | -86 |
| | Constraint costs | -99 | -339 | -55 | 69 |
| | Carbon costs | 4 | 85 | 5 | 14 |
| | **Decrease in power sector costs** | **-115** | **184** | **-31** | **99** |
| | | | | | |
| **Consumer bills** | Wholesale costs | -51 | -308 | -212 | -65 |
| | Capacity payments | -114 | -630 | -13 | -213 |
| | BSUoS | -50 | -169 | -27 | 34 |
| | Transmission losses | -38 | -131 | -41 | -31 |
| | Demand TNUoS charges | 0 | -28 | 30 | -40 |
| | Low carbon support | 106 | 382 | 97 | 417 |
| | **Decrease in consumer bills** | **-147** | **-884** | **-167** | **102** |

Aside from the distributional effects between generators, and the equitability issues which we have not been asked to assess, our analysis shows that WACM2 is likely to have a small positive impact on power sector costs in the longer run. For consumers the potential benefits are less clear cut mainly as the result of the effect of transmission charging changes on capacity prices. Consumers enjoy the benefit of lower power sector costs under WACM2 if the increase in costs from the increase in TNUoS for the marginal CM generator is smaller than the saving from low carbon support. This appears to be the case in the long run under a scenario where a high level of interconnector availability can be relied upon within the capacity requirement. However, there is a material risk that capacity prices could be higher under WACM2 depending on the exact parameters used for the capacity requirement and the capacity auction details. (It should also be noted that any increase in earnings associated with WACM2 for generators could be competed away elsewhere in the market.)

The implementation of EMR is an important factor in the analysis. The proposed approach for allocating CfDs to 2020 will be the most important driver of new renewable build, with transmission charging potentially having a small locational impact. 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. In terms of the Capacity Market, the assumed contribution to security of supply from interconnectors, and the manner in which these are included (if at all) in the auction, will not only impact on the overall costs of the CM, but also the effect of transmission charging on capacity prices. The relative cost differences due to transmission charging are small compared to the overall impacts of implementing EMR.

[11] Positive values represent benefits (cost decreases) under WACM 2 relative to the modelled version of Status Quo.

We have also conducted sensitivity analysis to support these conclusions. The sensitivity modelling indicates that both power sector costs and consumer bill impacts are relatively sensitive to the set of assumptions used; the range in power sector cost across the sensitivities in the period 2021-30 is £630m and for consumer costs is £1,016m.

A consistent theme across all sensitivities is the trade-off between the generation cost benefits of migrating capacity north (to access lower gas exit charges and higher onshore wind load factors) and the consequent increase in transmission investment costs, constraint costs and transmission losses.

The sensitivities further reveal the importance that EMR mechanisms have on the consumer bill costs and benefits of WACM2. Those sensitivities that simultaneously reduce the capacity requirement in the CM and produce greater savings in low support costs under WACM2 improve the impacts of WACM2.

In our core analysis we have assumed that transmission charges do not impact on generation dispatch decisions. However NERA/ICL argued that the Annual Load Factor link in WACM2 may cause a distortion of the generation dispatch merit order due to the indirect impact on short run marginal generation costs. We have separately analysed this potential effect in the TDM and conclude 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.

***Conclusions***

Based on the evidence considered, we conclude 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. The exception is if the marginal transmission investment diverges significantly from the mean trend in investment costs over a sustained period.

In our view, the NERA/ICL independent impact assessment does not reflect the likely outcomes under WACM2, and a scenario whereby both transmission ***and*** generation costs increase is very unlikely. We believe that the way that low carbon subsidies are assumed to be allocated in their modelling is the cause of the issue.

Based on consultation feedback we have enhanced the modelling approach used in Ofgem’s Impact Assessment. The updated analysis confirms that transmission costs are likely to increase, but generation costs reduce under WACM2. However, by eliminating differences in total volumes and type of renewables build, and differences in capacity margins, the updated analysis suggests that the differences relating purely to changing transmission charging are much smaller than previously assumed.

In the longer run, the analysis suggests a small reduction in overall power sector costs since the savings in generation costs are likely to outweigh the higher transmission costs. Were onshore transmission reinforcements available rather than more expensive HVDC bootstraps we expect that the savings demonstrated under WACM2 would be greater.

Whether consumers are able to benefit from potential reductions in power sector costs under WACM2 will critically depend on the impact of changing transmission charges on CfD and CM auction clearing prices. Depending on final aspects of EMR design, the way in which market participants respond to the new mechanisms, and future development of low carbon technologies, there is a risk that consumers could pay more under WACM2 despite reductions in underlying power sector costs.  Although there is significant uncertainty, we would expect the overall impact on consumers of WACM2 would be small in the context of the costs of EMR.

# Contents

# 1 Introduction

Project TransmiT is Ofgem's review of electricity transmission charging arrangements. As part of the Significant Code Review (SCR) under Project TransmiT, Ofgem commissioned Redpoint Energy to model the impacts of the transmission charging options considered. Two options were developed by the TransmiT Technical Working Group and were analysed in detail: (i) Improved Investment Cost Related Pricing (ICRP) which involves enhancements to the current ICRP methodology to include a year-round as well as a peaking element to transmission charges; and (ii) socialised charging under which all generators would pay a uniform tariff for using the transmission system, irrespective of their location or type. Redpoint developed a modelling suite, the TransmiT Decision Model (TDM), to model the impact of transmission charging regimes on transmission and generation investment decisions. With National Grid's support, we incorporated National Grid's Transport and Tariff model and ELSI model. The results of our study were published in December 2011[12].

The conclusion of Ofgem's SCR[13] on Project TransmiT included a direction for the Connection and Use of System Code panel (CUSC panel) to develop a modification to the CUSC (CMP213) based on the Improved ICRP approach. National Grid undertook further analysis and modelling in the TDM to assess proposals developed under CMP213. The key features of the Improved ICRP option were retained in the Original proposal that National Grid raised as CMP213. Additionally, National Grid's analysis included four more charging options: (i) Original 50% HVDC, which uses a similar approach as the Original, however with a reduction in converter cost by 50% for both parallel HVDC circuits and island connections comprised of sub-sea HVDC cable technology; and (ii) three Diversity options (Diversity 1, Diversity 2 and Diversity 3) that aim to recognise diversity between low-carbon and fossil fuel generation in the use of transmission infrastructure.

In Summer 2013, Ofgem commissioned Redpoint to perform a review of this analysis[14]. (In addition, that report contains a description of the features of the different charging options considered.) This was published alongside Ofgem's Impact Assessment[15] in August 2013, which announced a minded-to position to approve the option known as "Workgroup Alternative Connection and Use of System Code (CUSC) Modification 2 (WACM2)". This option is the Diversity 1 option referred to above. The consultation on the Impact Assessment closed in October 2013.

Through the consultation process on its minded-to position, Ofgem received a wide range of feedback including a number of challenges to its conclusions and the underlying analysis supporting these conclusions. The most extensive responses were provided by RWE npower and Centrica, with supporting reports respectively from NERA/Imperial College London (ICL) and Pöyry. RWE submitted two reports from NERA/ICL (*Review of Ofgem Impact Assessment of Industry Proposals CMP213*[16]

[12] Modelling the impact of transmission charging options – A report by Redpoint Energy, December 2011. Available at: http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

[13] https://www.ofgem.gov.uk/ofgem-publications/54066/transmit-scr-conclusion-document.pdf

[14] https://www.ofgem.gov.uk/ofgem-publications/82377/cmp-213-modelling-review-cmp213-impact-assessment-modelling-ofgem-redpoint-energy.pdf

[15] https://www.ofgem.gov.uk/ofgem-publications/82538/projecttransmitimpactassessmentofcmp213options.pdf

[16] http://www.nera.com/nera-files/130909_Review_of_Ofgem_Impact_Assessment_of_Industry_Proposals_CMP213.pdf

and "*Modelling the Impact of the WACM2 Charging Model,* referred to throughout this document as the NERA IA review and the NERA modelling report respectively). Centrica submitted a report from Pöyry (*Review of Ofgem's Impact Assessment on CMP213*[17]*,* referred to throughout as the Pöyry report).

In addition, Ofgem has had further communication with RWE, NERA and ICL via emails and meetings to clarify aspects of the responses. A further report, *Assessing the cost reflectivity of Alternative TNUoS Methodologies* (referred to as the NERA Cost Reflectivity report throughout this document) was received from NERA/ICL.

Ofgem commissioned Redpoint Energy to review these consultant reports to assess the validity of the arguments raised and to understand the differences between the analysis presented in these reports and the work undertaken by National Grid in support of the CMP213 Impact Assessment. We were also asked by Ofgem to update the Impact Assessment modelling to address comments received through the consultation phase, and to take into account the latest policy positions on Electricity Market Reform (EMR) which have evolved considerably since the original analysis was undertaken.

This report summarises our work on the above areas and is structured as follows:

- In Section 2 we review the main arguments raised by NERA/ICL and Pöyry;
- In Section 3 we review the quantitative analysis presented by NERA/ICL;
- In Section 4 we present our updated analysis of Status Quo and WACM2; and
- Finally, in Section 5 we present our conclusions.

The appendices include supplementary results of our analysis and additional review of NERA/ICL analysis.

[17] http://www.nera.com/nera-files/131009_WACM2_Modelling_Report.pdf

# 2 Review of issues raised by NERA/ICL and Pöyry

## 2.1 Overview

In this section we review the main arguments made in the reports and present our responses, focusing on those points relating to the quantitative analysis.

## 2.2 Investment principles

The Security and Quality of Supply Standard (SQSS) sets out criteria and methodologies for planning and operating the GB Transmission System. The SQSS, as modified by GSR009, sets out a dual background approach for assessing reinforcements. The Demand Security criterion ensures that peak demand can be met (without intermittent generation). The Economy criterion incorporates a pseudo-Cost Benefit Analysis (CBA) approach for assessing transmission reinforcements, which is based on a generic CBA considering the trade-offs between transmission investment costs and constraint costs.

The WACM2 charging approach better reflects the principles of a full Cost Benefit Analysis, by taking account of the annual load factor of generators as a proxy for their impact on constraints. Both the NERA/ICL and Pöyry reports argue that the WACM2 approach is at odds with the pseudo-CBA economic criterion in the SQSS. The reports identify a number of areas in which WACM2 is not aligned to the SQSS. For example, the SQSS prescribes fixed scaling factors in the economy background whereas the WACM2 charges on the basis of Annual Load Factor[18]. In fact, we believe the latter approach is more reflective of a full CBA.

The Authority in its determination on GSR009 explicitly recognised that investment decisions by TOs could deviate from the SQSS Economy criterion (particularly for larger investments), and that adopting a full CBA approach is a valid basis for investment decision making. Therefore, we believe that it is appropriate for WACM2 to differ from the pseudo-CBA in the SQSS, in order to better reflect a full CBA.

The reports claim that the SQSS Economy criterion will typically lead to a higher level of investment than a full CBA. They go on to base a number of arguments on the logic that the SQSS Economy criterion sets a minimum level of reinforcement.

This conclusion is not correct. It is clear that a full CBA may indicate a higher or lower amount of investment, depending on the specific options available. For example, because transmission reinforcement is lumpy, constraint costs in certain years will have to rise to the level at which otherwise oversized assets are economic compared to no reinforcement, which might delay reinforcement. The SQSS level could be either above or below the economically efficient level because different boundaries have different generation mixes behind them which the pseudo-CBA may not fully reflect.

[18] WACM2 uses the generation background condition established by the generic scaling factors under the economy criterion, and uses the generator specific ALFs in the calculation of tariffs.

We note that the NERA/ICL modelling framework used for their analysis uses a full CBA approach for transmission investment decision making.

## 2.3 Demonstrating cost reflectivity

Both the Pöyry report and the NERA IA review claim that the IA does not provide sufficient evidence that the WACM2 approach is more cost reflective than the Status Quo, and it is true that there is no direct comparison of the transmission costs related to different generation types in different locations and the transmission charges that they face.

***Comparison of constraint cost impacts to SQ and WACM2 tariffs***

In our analysis (Section 4), transmission reinforcements are specific projects with defined capacities across one or more boundaries (i.e. reinforcements are lumpy). Multiple boundaries have an impact on a particular zone as there is not a one-to-one mapping of reinforcements to boundaries. Therefore, there is not a single simple definition of the Long Run Marginal Cost (LRMC) impact on transmission from each generator type.

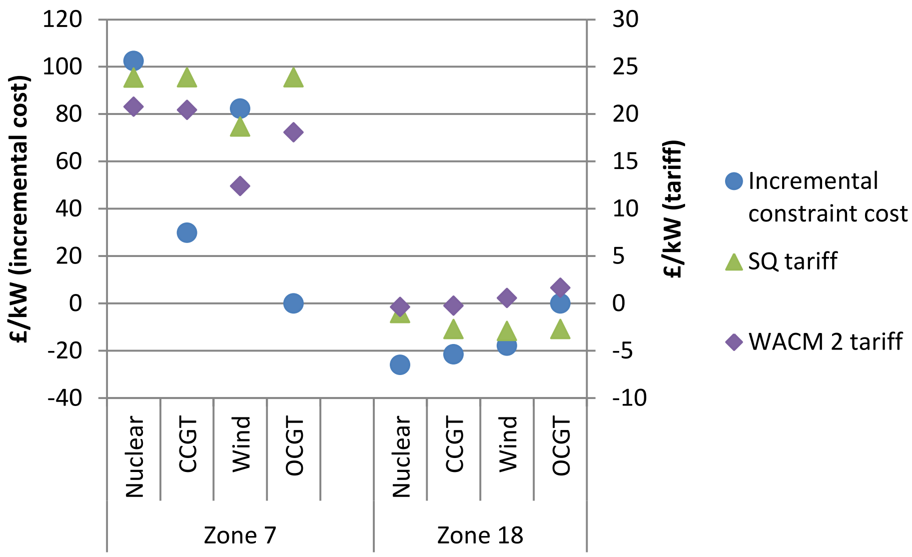
To address this cost reflectivity point, we have used our modelling to compare the relative impact of generators on transmission costs to the tariffs they face under Status Quo and WACM2. This analysis is illustrative and is based on the modelling described in Section 4. To attempt to represent the LRMC for a specific zone, we have considered the impact on constraint costs of an additional MW of generation. There is a close relationship between constraint costs and LRMCs of reinforcement because reinforcement occurs when constraints on a particular boundary exceed the annuitised cost of the reinforcement. Because transmission reinforcement is lumpy, constraint costs in certain years will have to rise to the level at which oversized assets are economic compared to no reinforcement. The absolute level of the impact of a generator on constraints in any one year may vary from zero (if there is spare capacity) to many times the reinforcement cost (if the available reinforcement is very large). Therefore, we consider an individual boundary in the year prior to reinforcement, to ensure that the constraint costs are approaching the level at which reinforcement is economic, and hence constraint costs are a good proxy for incremental transmission reinforcement costs. To consider whether ALF is an appropriate driver of transmission investment, we consider the relativities of tariffs compared to the relativities in the incremental impact on constraints.

We have considered 2021, which is the year prior to the commissioning of the Eastern HVDC #2[19] under the updated modelling, mainly to relieve a constraint on boundary B7a. Figure 1 shows the incremental costs in 2020, alongside the Status Quo and WACM2 tariffs for 2021 (once the HVDC bootstrap has been commissioned and affects tariffs), for Zone 7 (South Scotland) and Zone 18 (Oxon & South Coast). Nuclear is assumed to have an 80% load factor, and the load factors for wind and OCGT are 28% and 0% respectively. New CCGT is charged based on a 70% load factor, but the actual load factor (calculated by the dispatch model) is lower (~50%), mainly due to the competitiveness of coal generation under DECC's UEP commodity price assumptions. In Zone 7, plant with higher load factors increase constraints, whereas in Zone 18 the reverse is true. Under WACM2, tariffs reflect the incremental impact to some extent (showing a relationship to load

[19] Eastern HVDC Link #1 is also available as a reinforcement option but is not built by the model under the particular scenarios and assumptions modelled. Eastern HVDC Link #2 reinforces fewer boundaries, but at a lower cost.

factor), whereas the Status Quo tariffs do not[20]. (Note that the OCGT tariff under WACM2 does not drop to zero because it is still charged the peak security tariff and the Year Round Non shared tariff.)

**Figure 1 Incremental constraint costs, load factors (2020) and tariffs (2021)**




The relationship between ALF and incremental constraint cost appears to be reasonable, except that wind appears to have a greater impact on constraints than a CCGT running at a higher load factor. As the wind capacity increases towards 2020, the correlation of wind outputs means that wind load factors in constrained periods will typically be higher than year round (and the reverse may be true for CCGTs). The analysis shows that ALF and diversity factors, whilst far from being a perfect representation of the impact of generators on constraints, are likely to be a reasonable proxy, and better than taking no account of load factor at all[21]. Therefore it is likely that WACM2 is a better reflection of the incremental impacts of different generator types on transmission costs than the Status Quo charging methodology.

***Arguments regarding the use of Annual Load Factor in WACM2***

Both reports claim that the use of annual load factors (ALFs) is not a good proxy for the need for reinforcement, relying heavily on the University of Bath study[22] as evidence.

The CMP213 Workgroup performed analysis of relationship between load factor and constraint costs. NERA/ICL make the point that the scatter plots in Annex 9 of the FMR document (relating constraint costs to capacity of different technologies) are based on an extremely small number of data points. Whilst this is true, the relationship is reasonably consistent across all zones, and is

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[20] The reason that wind has a lower tariff under Status Quo (when wider tariffs for all technologies in the same zone are equal) is due to the Small Generator Discount which will apply to a proportion of wind projects in Scotland

[21] In this analysis we have not been able to separately identify the impacts of ALF and diversity factors

[22] CMP213 FMR, Volume 3, page 180 onwards. http://www.nationalgrid.com/NR/rdonlyres/48D10E02-5CB5-422E-8515-98E0171E1A2A/61006/FinalReportVolume3v10FinalReport.pdf

supported by our own analysis above (Figure 1). Furthermore, if the ELSI model is a key component of National Grid decision making, it is by definition reflective of the costs that it bases its investment decisions on (for England and Wales).

Pöyry identifies a number of perceived anomalies where ALF is not a perfect proxy for impact on constraint costs. For example, in a zone with a high concentration of wind and therefore little sharing, an OCGT would pay nearly as much for year round as wind in a zone with no sharing assumed, even though the impact on constraint costs from the OCGT may be minimal. Another point made is that the average load factor of wind when the system is constrained would be a lot higher than average load factor of wind across the year. This is likely to be true for zones with a high penetration of wind.

Whilst it would be difficult to argue that ALF was a perfect proxy, and the examples provided are good ones, it is also difficult to argue that the Status Quo approach is a better reflection of underlying drivers for reinforcement.

We note that the use of ALF to represent the impact on constraints (modified by diversity factors) is the best that the industry has come up with in the Workgroup process, and one that National Grid confirms is reflective of the underlying basis on which decisions are made.

Overall, we believe that the WACM2 methodology is more cost reflective than the Status Quo in recognising the dual drivers of transmission investment. NERA/ICL have also performed cost reflectivity analysis which we review (Section 3.3) and which we interpret to show that WACM2 would also be more cost reflective all generation types, but for the higher costs of the HVDC links and converter stations.

## 2.4 Impact Assessment modelling approach

Both the Pöyry report and the NERA IA review raise issues with the Ofgem IA modelling approach.

In this section we respond to the following issues:

- The impact of the higher level of renewable generation in Status Quo compared to WACM2
- The impact of volatile capacity margins on wholesale prices
- Possible distortions to dispatch from the ALF element of WACM2
- The impact of the low carbon generation mix
- The need for additional sensitivity analysis, which is stressed in both reports

We have performed additional analysis including enhancements to the TDM to account for the issues raised. This is described in Section 4.

***The impact of the higher level of renewable generation in Status Quo compared to WACM2***

In our review of the Ofgem IA analysis, we noted that one of the drivers of differences in power sector costs between Status Quo and Diversity 1 (WACM2) was the difference in total renewables penetration.

*The NPV of generation costs were found to be considerably lower under the Original 50% HVDC and Diversity 1 charging options due to savings in generation capital costs and fixed costs associated with replacing expensive offshore wind with onshore wind. By 2030 Diversity 1 results in the lowest overall renewable level (31.3% as seen in Table 32) and as a result this also reduces generation costs* *and thus presents the Diversity 1 run in a more favourable light than if the renewable generation matched exactly.*

Table 4 shows the deployment of major low carbon technologies in the Ofgem IA analysis and the resulting renewables penetration and carbon intensity, in 2020 and 2030. Diversity 1 has an additional 1.2 GW of offshore wind, partially offset by a 300 MW reduction in onshore wind. This leads to a difference of 3 TWh in renewable generation in 2020 and 6 TWh in 2030.

**Table 4 2020 and 2030 carbon intensity and renewable penetration results – Status Quo and Diversity 1**

| | Status Quo (2020) | Diversity 1 (2020) | Status Quo (2030) | Diversity 1 (2030) |
|---|---|---|---|---|
| Onshore Wind (GW) | 9.6 | 9.9 | 11.1 | 11.4 |
| Offshore Wind (GW) | 11.3 | 10.1 | 12.2 | 10.1 |
| Renewable Penetration (%) | 30.4% | 29.6% | 32.8% | 31.3% |
| Nuclear (GW) | 7.6 | 7.6 | 14.8 | 14.8 |
| CCS (GW) | 1.1 | 1.1 | 8.4 | 9.3 |
| Carbon intensity (g/kWh) | 246.8 | 252.1 | 99.0 | 99.5 |

NERA/ICL noted this point in Section 4.2.3 of their IA review report, and estimated the cost impact of having additional renewables (as opposed to the impact of different mixes of renewables which are an outcome of the tariff modelling). Using assumptions on the levelised costs of CCGTs, onshore wind and offshore wind, NERA/ICL calculated the cost of additional renewables to be 60 £/MWh. The resulting estimate for the NPV cost of additional renewable was £2.12bn on a NPV basis.

We have recreated this calculation, using the actual levelised costs from the modelling (which NERA/ICL did not have access to). The resulting cost of additional renewables under Status Quo is £1.20bn, which is lower than the total reduction in power sector costs under Diversity 1 of £1.95bn. Therefore, after accounting for the value of the additional renewables in Status Quo, WACM2 would show a net reduction in power sector costs of around £750m.

In the updated analysis in Section 4, our updated approach to CfD allocation means that the capacity of each low carbon generation type is unchanged between Status Quo and WACM2. It is only the location of generation that changes.

***The impact of volatile capacity margins on wholesale prices***

The reports highlight known issues surrounding difficulty in interpreting results where capacity margins (and hence wholesale prices) differ. These caveats in interpreting the results were highlighted in our review of the NG analysis. Due to the impact of capacity margin variability the NG analysis of consumer costs cannot be relied on (in a future world of capacity payments), and hence we have updated the modelling approach as described in Section 4.2.

*Possible distortions to dispatch from the ALF element of WACM2*

Section 3.3 in the NERA/ICL report considers the potential distortions to dispatch arising from a £1/kW Year Round Shared tariff for a generator under WACM2. NERA/ICL conclude that there is an NPV saving of £10,965 in TNUoS for a 200 MW generator which reduces its generation by 100 GWh/year for two years.

Section A.2 includes analysis of the potential impact of dispatch distortions, using our updated WACM2 model run. From our analysis we can conclude that the potential dispatch distortion from WACM2 is 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.

*Impact of low carbon generation mix*

Pöyry notes that there is a high amount of nuclear and CCS capacity after 2020 and little increase in onshore and offshore wind. The implication was that these input assumptions were driving much of the consumer benefit observed in NGET's analysis.

The specific target for nuclear generation in 2030 of 14 GW was the result of a Workgroup decision to fix a level of nuclear. The CCS projects available in the model were all based on named proposals and so represent a plausible set of projects, assuming that funding is available.

The ratio of onshore to offshore wind was influenced by the increase in the total available offshore wind capacity by 2020 to reflect the latest National Grid 2012 Accelerated Growth scenario, which makes ambitious assumptions in terms of total possible offshore wind deployment (33 GW by 2020). We note that in National Grid's Future Energy Scenarios[23], the Accelerated Growth scenario has been 'retired'. We also note that the overall impact of the change on the output build is restricted by the global build constraints on offshore wind (7.5 GW/year) and by the profitability of projects under the CfD levels used.

Pöyry notes that there is no assumed growth in Solar PV. This assumption does not reflect the latest assumption in DECC Final Delivery Plan[24] of 2.4-4 GW of large scale solar PV by 2020. The main impact of distribution connected solar PV would be to reduce the amount of renewable generation required by up to 3 TWh, and to reduce net demand by the same amount. Any locational impact would depend on whether the distribution of solar PV is similar to the distribution of demand across GB.

Biomass conversion was treated through changes to capacities and fuel type of existing generators in the model.

In the updated analysis, as well as an Original Case using the assumptions from the Ofgem IA, we have modelled an Alternative Case, a feature of which is increased levels of renewables by 2030 and decreased levels of nuclear and CCS, relative to the Original assumptions.

[23] http://www2.nationalgrid.com/uk/Industry-information/Future-of-Energy/

[24] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268221/181213_2013_EMR_Delivery_Plan_FINAL.pdf

***Additional sensitivity analysis***

The need for additional sensitivity testing is stressed throughout both reports. We have modelled two main Cases and four additional sensitivities, described in Sections 4.3 and 4.4.9.

***Summary***

Table 2 summarises how we have addressed the issues raised.

**Table 5 Issues raised with Ofgem IA analysis**

| Issue | Treatment in updated analysis |
|---|---|
| The impact of the higher level of renewable generation in Status Quo compared to WACM2 | Total capacity of each renewable generation type equalised between Status Quo and WACM2 |
| The impact of volatile capacity margins on wholesale prices | Implementation of new Capacity Market modelling approach |
| Possible distortions to dispatch from the ALF element of WACM2 | Additional analysis which demonstrates that this is a small effect and would be outweighed by savings in constraint costs and transmission losses |
| The impact of the low carbon generation mix | Two cases modelled, with different low carbon generation mixes in 2030 |
| The need for additional sensitivity analysis, which is stressed in both reports | Four sensitivities modelled |

## 2.5 Market Impacts

Both reports raise concerns regarding the distributional effects, and link this to the timing of implementation. Both reports noted that if implementation were to occur in 2014, parties would not be able to react to TNUoS signals. However, Ofgem's latest minded to position is for an implementation date of 1st April 2016 (if Ofgem were to accept the modification). In any case, these arguments can be refuted, to a degree, if the current arrangements are considered discriminatory due to lack of cost reflectivity relative to the alternative.

Pöyry cites precedence regarding the BSC P229 decision which suggested that modifications that have low net welfare impacts, but significant distributional impacts, should be rejected. A further point that both reports make is that change is not justified if wider change, such as market splitting, is coming. Ofgem will need to give due consideration to the validity and importance (or otherwise) of these arguments.

# 3 Review of quantitative analysis

## 3.1 Overview

In this section we present our review of the quantitative analysis provided by NERA/ICL. As well as the main body of the separate modelling report, this review covers the calculation of tariffs on a simple schematic network presented in Appendix B of that report.

## 3.2 NERA/ICL quantitative modelling

***Overall approach***

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.

NERA/ICL's modelling approach has previously been reviewed. In 2011, Redpoint Energy[25] and Oxera[26] separately reviewed NERA/ICL's modelling of ICRP compared to a uniform (socialised) charging methodology. In July 2013, Oxera produced a further review[27] of NERA's October 2012 assessment of Improved ICRP.

There are a number of concerns with the NERA/ICL approach which have been raised previously. The iterative approach for converging on a combined generation and transmission investment outcome is highly sensitive to small changes in assumptions, as shown by the sensitivity of the results between iterations to small changes in transmission charges. As a result, the degree of convergence to an "optimal" solution (and indeed how convergence is interpreted) is influenced by user judgement of the results of iterations. NERA/ICL attempt to address this by averaging the results across iterations, but it is not clear that this addresses the underlying issue.

When the iterations converge, the modelling approach represents a perfect foresight world in which decision making on generation and transmission investment is made with full knowledge of future tariffs and profitability. This approach does not reflect the imperfect view of the future that investors have to assess to when they make their decisions.

NERA/ICL emphasise the differences in how they model subsidies relative to the NG/Redpoint approach used for the Ofgem IA. We acknowledge that there were weaknesses in the previous approach, given that there was little information on how allocation of CfDs would work. We have

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[25] Redpoint Energy, A review of "Project TransmiT: Impact of Uniform Generation TNUoS prepared for RWE npower", https://www.ofgem.gov.uk/ofgem-publications/85165/consultationresponsefromsse5.pdf

[26] https://www.ofgem.gov.uk/ofgem-publications/54270/oxera-critique-nera-imperial-report.pdf

[27] https://www.ofgem.gov.uk/ofgem-publications/85164/consultationresponsefromsse4.pdf

updated the approach to reflect the latest policy positions from DECC on the allocation of CfDs. The NERA/ICL approach is not reflective of current policy.

The NERA/ICL approach minimises the subsidy required to meet a particular renewables target (after 2017 when the RO closes to new accreditations). The perfect foresight assumption is unrealistic but more importantly seems to be driving some anomalous results, explored further below, which appear to be suggesting that more expensive onshore and offshore wind projects would be deployed earlier under WACM2. This is not a good reflection of likely outcomes, since in reality given the same support level we would expect cheaper sites to be developed first. This different approach to modelling renewable support appears to be at the heart of the differences in the modelling results.

Transmission investment is optimal under the NERA/ICL approach, which we assume means linear expansion of boundaries to any MW level is possible. Whilst this may mean that results are more stable than they would otherwise be and therefore more likely to converge, this does not reflect the true lumpiness of transmission investments.

NERA/ICL point out their approach to modelling dispatch is superior to that in National Grid's ELSI model since it takes into account unit commitment and dynamic constraints. This may be true but we do not consider that this materially affects the results in this context. In designing the TransmiT modelling framework we actively took the decision to use the simplified ELSI model over a more detailed market dispatch model, such as PLEXOS, in order to speed up run times. However, we used PLEXOS to calibrate key outputs from ELSI such as constraint costs. National Grid uses ELSI for network planning studies which confirms its relevance as a tool for assessing constraint costs and transmission investments.

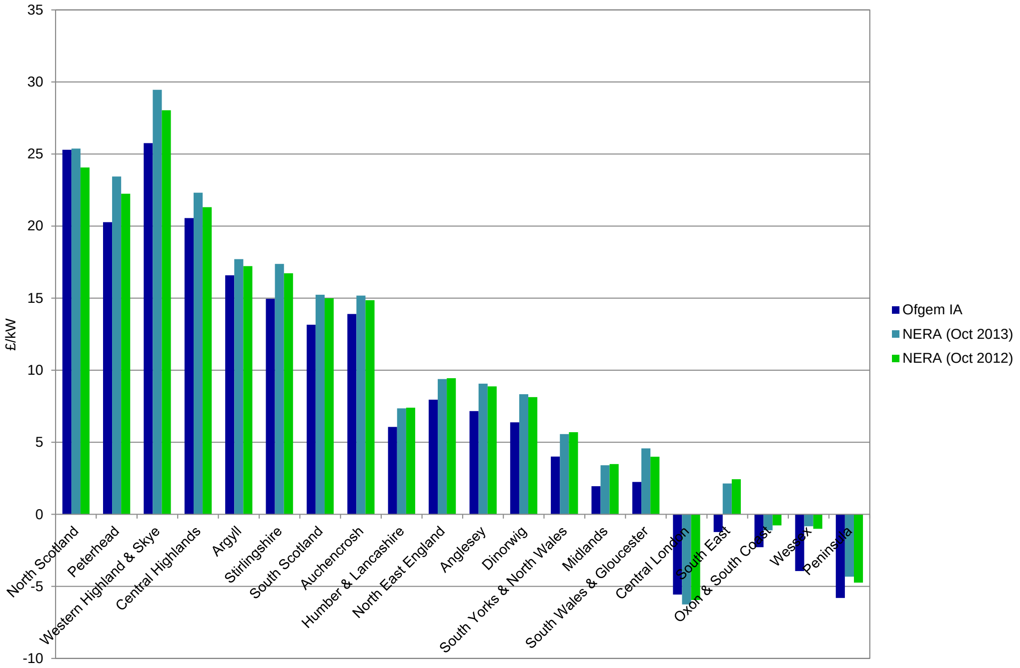
***Tariff modelling***

In the October 2012 report (Section 2.3.2, Figure 2.2), NERA/ICL present charts showing the 2012 Status Quo tariffs from the NERA/ICL modelling compared to the published 2012/13 generation tariffs. These tariffs showed a close match.

The October 2013 NERA/ICL report does not present calibration of WACM2 tariffs. In their responses to Ofgem's queries, NERA/ICL argue that there was not sufficient time or a clear background to compare the tariffs to because their model uses data from October 2012, whereas the latest published tariffs under WACM2 use more up to date data and are based on 27 generation zones.

In the figures below, we compare the 2014 tariffs from the NERA/ICL modelling (both 2012 and 2013) to those in the Ofgem IA. We note that the models use different generation and demand backgrounds and therefore a very close match is not necessarily to be expected. Figure 2 shows the Status Quo tariffs are close given potentially different input assumptions. The NERA/ICL tariffs are higher on average by around 1.8 £/kW suggesting a higher residual component. The relative differences across the zones are consistent between the Ofgem IA values and the NERA values.

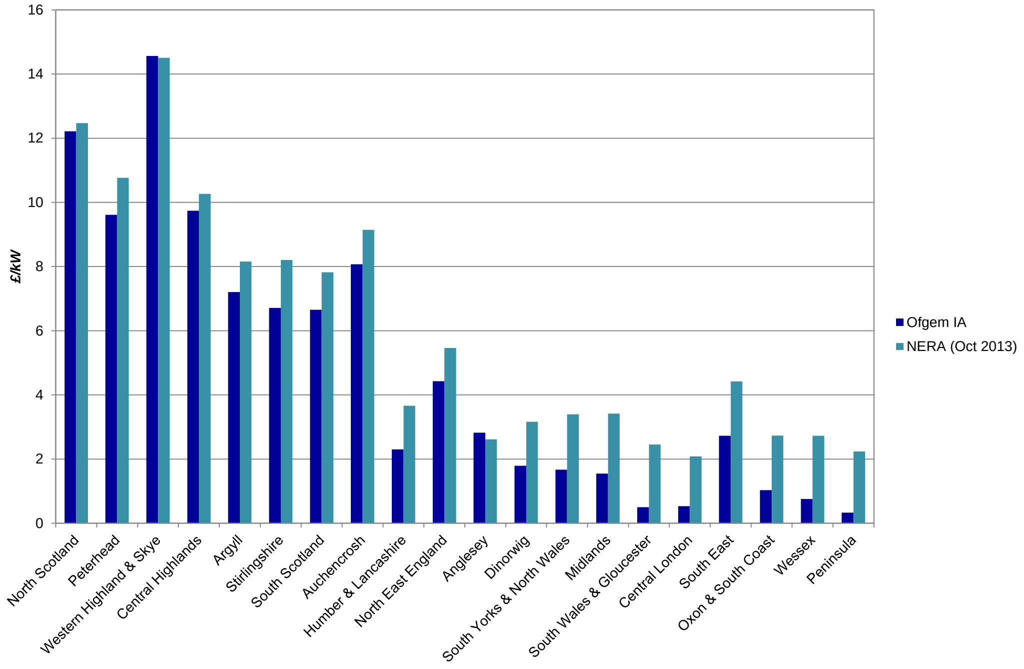
**Figure 2** **Status Quo tariffs, 2014**




Source: Ofgem & NERA/ICL

The NERA/ICL WACM2 tariffs are similarly higher on average than the Ofgem IA values, due to a 1.75 £/kW difference in residual tariffs. The comparison of tariffs for a wind generator with a 30% load factor (Figure 3) indicates that the zonal differences in tariffs are similar, although the NERA/ICL modelling has relatively higher tariffs for all zones, except Western Highlands & Skye, and significantly higher in the south of England.

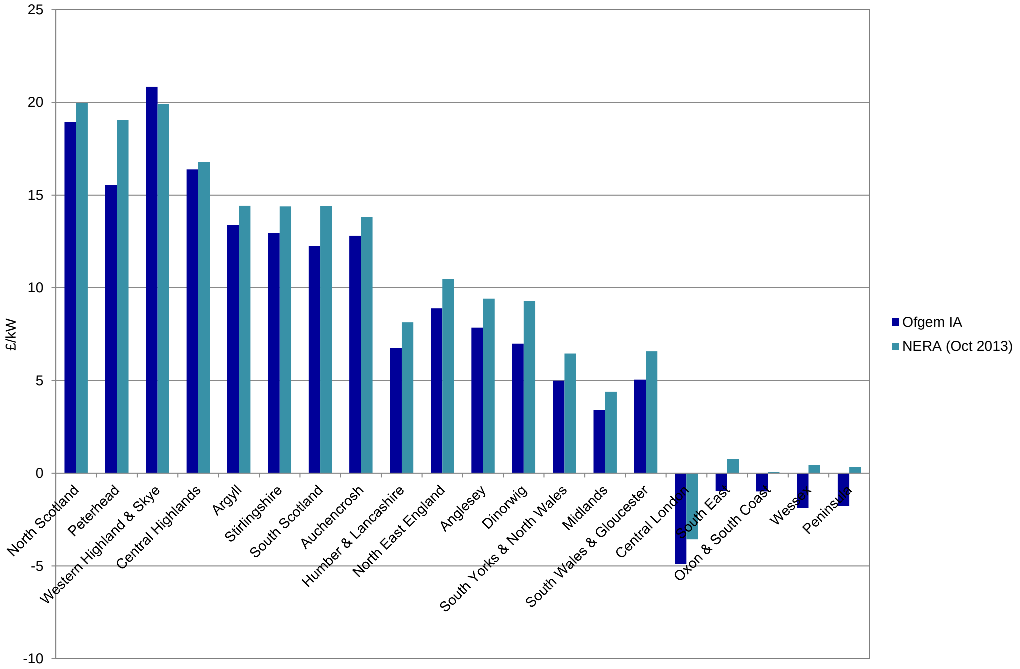
**Figure 3 WACM2 tariffs, wind 30%, 2014**




Source: Ofgem & NERA/ICL

The comparison of tariffs for a conventional generator with a 70% load factor (Figure 4) indicates a less pronounced difference in tariffs in the south of England, although certain tariffs are positive rather than negative.

**Figure 4 WACM2 tariffs, conventional 70%, 2014**




Source: Ofgem & NERA/ICL

Overall, the comparison above indicates that it is likely that NERA/ICL have modelled the key features of WACM2 (that are relevant in 2014) in a similar manner to the Ofgem IA modelling.

It is not meaningful to perform a comparison of tariffs for later years as the generation (and resulting transmission) backgrounds will evolve in difference ways. In particular the timing of HVDC bootstraps is likely to be different and will have a significant impact on tariffs.

***Amount and location of onshore and offshore wind***

In the NERA/ICL results, generation costs increase by £1,157m in NPV terms between 2014 and 2020, and by £2,895m between 2021 and 2030. This is a significant difference to our analysis which shows reductions in generation costs over these periods. The major driver of the higher generation costs originates in the amount, location, and timing of deployment of onshore and offshore wind.

We understand that NERA/ICL's renewables subsidy module optimises the level of onshore and offshore wind subsidies to meet the 2020 renewable electricity target at lowest subsidy cost to consumers, assuming that renewables investors aim to maximise profit. It does this by testing subsidy levels at intervals of about £6.5/MWh for onshore wind and about £8.5/MWh for offshore wind, for two periods (2017-2023 and 2024-2030). For each scenario of subsidy levels tested, the most profitable wind investments are selected, subject to constraints on deployment. The scenario selected is that which meets the renewables target at lower cost than any other set of subsidies tested.

For the reasons described below we do not believe this is delivering a credible outcome for the differences in renewable build between Status Quo and WACM2.

The wind input data is described in NERA/ICL's October 2012 report[28]. For onshore wind, NERA/ICL model 21 onshore wind regions including two Scottish Island groups. For the mainland wind, load factors vary within a region as shown in Table 6. Each load factor corresponds to a proportion of the capacity available in the region. We note the additional granularity in these assumptions relative to our own modelling. However, the data is from a single year and therefore may not be representative of the true range in load factors.

**Table 6 Onshore wind load factors (NERA/ICL modelling)[29]**

| | Percentile | | | | | |
|---|---|---|---|---|---|---|
| **Location** | **0.1** | **0.3** | **0.5** | **0.7** | **0.9** | **Mean** |
| Western Isles | 35.0% | 35.0% | 35.0% | 35.0% | 35.0% | 35.0% |
| Shetlands | 49.0% | 49.0% | 49.0% | 49.0% | 49.0% | 49.0% |
| Highlands | 46.9% | 39.3% | 34.5% | 30.3% | 23.7% | 33.4% |
| Aberdeenshire | 43.9% | 37.5% | 32.9% | 28.8% | 23.1% | 31.6% |
| Perth & Kinross | 35.5% | 31.8% | 28.0% | 25.3% | 21.7% | 26.9% |
| Angus & Fife | 38.6% | 36.5% | 35.6% | 33.6% | 24.8% | 31.5% |
| Argull & Bute | 36.4% | 31.8% | 27.6% | 25.6% | 22.7% | 27.7% |
| Borders | 34.8% | 32.3% | 29.3% | 26.9% | 25.7% | 28.7% |
| North England | 37.7% | 29.3% | 26.5% | 22.4% | 17.3% | 25.4% |
| Yorkshire | 35.5% | 30.0% | 27.4% | 24.1% | 20.6% | 26.0% |
| Northwest England | 35.5% | 30.0% | 27.4% | 24.1% | 20.6% | 26.0% |
| North Wales | 32.8% | 32.2% | 31.7% | 31.1% | 30.5% | 30.4% |
| Lincolnshire | 35.8% | 30.3% | 26.8% | 25.4% | 23.1% | 26.4% |
| West Midlands | 32.3% | 31.2% | 28.2% | 24.8% | 19.9% | 26.1% |
| East Anglia | 33.7% | 30.9% | 27.6% | 25.1% | 21.2% | 26.2% |
| South Wales | 32.8% | 30.3% | 27.1% | 23.8% | 19.6% | 25.6% |
| Wiltshire | 32.8% | 30.3% | 27.1% | 23.8% | 19.6% | 25.6% |
| London | 29.3% | 28.5% | 27.7% | 26.8% | 26.0% | 26.6% |
| Kent & Thames Estuary | 29.3% | 28.5% | 27.7% | 26.8% | 26.0% | 26.6% |
| Devon & Cornwall | 33.0% | 29.0% | 27.2% | 25.5% | 23.3% | 26.8% |
| South Coast | 22.5% | 20.6% | 16.8% | 13.2% | 12.1% | 16.5% |

*Source: NERA/Imperial analysis of Ofgem data*[30]

For offshore wind, NERA/ICL model 26 projects (Table 7). For offshore wind the load factors do not vary within a location.

[28] http://www.nera.com/nera-files/PUB_Transmit_1012_full.pdf

[29] NERA/ICL document submitted to Ofgem: *140205 Renewables Workbook.xlsx*

[30] Based on a single year of data from Ofgem's ROC register.

**Table 7 Offshore wind load factors (NERA/ICL modelling)** [31]

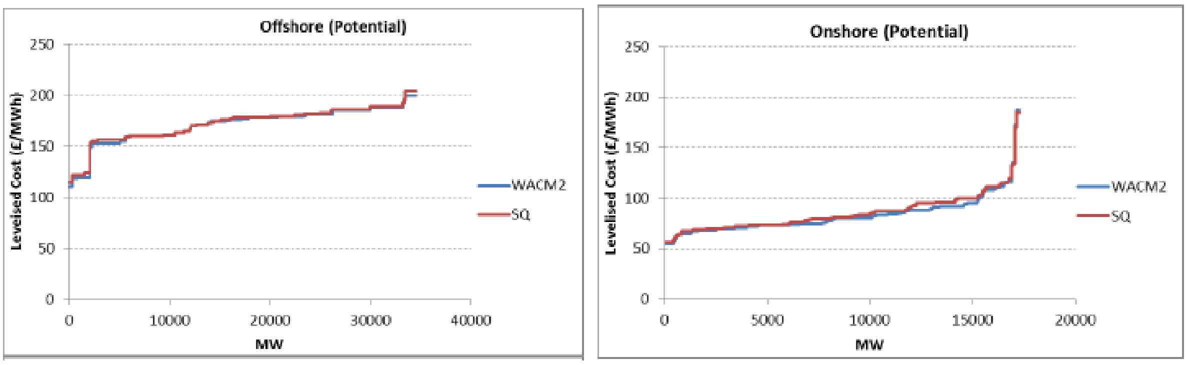
| Location | Load Factor (%) |
|---|---|
| Docking Shoal | 32.9% |
| Race Bank | 35.4% |
| Humber Gateway | 32.9% |
| Triton Knoll | 35.4% |
| Westermost Rough | 30.4% |
| Dudgeon | 35.4% |
| London Array II | 32.9% |
| Gwynt y Mor | 35.4% |
| West of Duddon Sands | 37.9% |
| Bristol Channel | 40.4% |
| Dogger Bank | 42.9% |
| Firth of Forth | 42.9% |
| Hastings | 35.4% |
| Hornsea | 37.9% |
| Irish Sea | 40.4% |
| Moray Firth | 32.9% |
| Norfolk Bank | 37.9% |
| West of Isle of Wight | 35.4% |
| Argyll Array | 47.9% |
| Beatrice | 32.9% |
| Forth Array | 37.9% |
| Inch Cape | 35.4% |
| Islay | 45.4% |
| Kintyre | 47.9% |
| Neart na Gaoithe | 35.4% |
| Solway Firth | 30.4% |

*Source: NERA/Imperial analysis of Carbon Trust and Wind Atlas (http://www.renewables-atlas.info/downloads/documents/Renewable_Atlas_Pages_A4_April08.pdf) data*

The associated costs and capacity data is described in NERA/ICL's October 2012 report, and have been summarised by NERA/ICL in the supply curves in Figure 5. The charts stack the projects in levelised cost order, left to right. For onshore wind, the supply curve is lower under WACM2 which is what would be expected. The differences are particularly significant for projects over the 30,000 GWh mark.

[31] NERA/ICL document submitted to Ofgem: *140205 Renewables Workbook.xlsx*

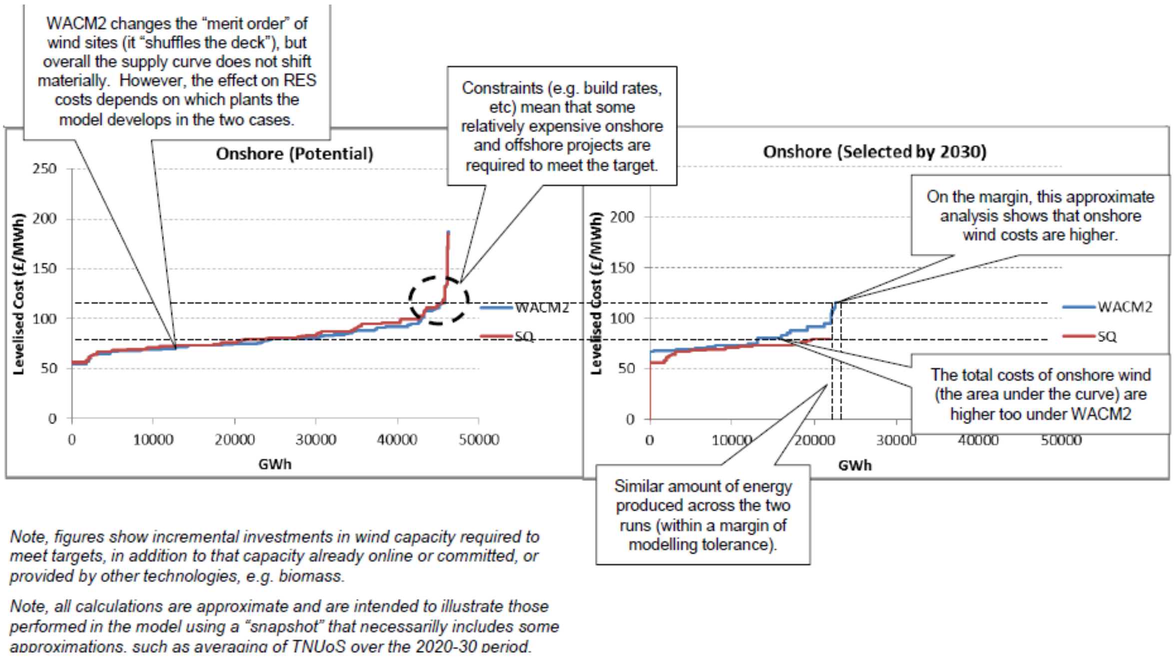
**Figure 5 Supply curves of potential wind projects (NERA/ICL modelling)** [32]




Source: NERA/ICL

Figure 6 shows the selected onshore wind projects under SQ and WACM2. The chart on the left shows potential projects and the chart on the right those actually built by the model. The supply curves of built projects shows the WACM2 curve above the SQ curve throughout. We note that the cheapest onshore wind available under WACM2 is not built by the model.

**Figure 6 Supply curves of potential and selected onshore wind projects (NERA/ICL modelling)** [33]




Source: NERA/ICL

[32] NERA/ICL document submitted to Ofgem: *2nd DRAFT - Slides for Ofgem Meeting.pdf*

[33] NERA/ICL document submitted to Ofgem: *2nd DRAFT - Slides for Ofgem Meeting.pdf*

The resulting wind build in aggregate is shown in Table 8. NERA/ICL's results for WACM2 have more than 1.8 GW of wind capacity in aggregate than under Status Quo, of which 350 MW is offshore wind.

**Table 8 Wind capacity built under SQ and WACM2 (NERA/ICL modelling)** [34]

**Status Quo**

| Renewables (GW) | 2020 | 2030 |
|---|---|---|
| Offshore E&W East Coast | 0.73 | 0.73 |
| Offshore E&W South Coast | 2.55 | 2.55 |
| Offshore E&W West Coast | 1.22 | 1.22 |
| Offshore Scotland East Coast | 1.30 | 1.79 |
| Offshore Scotland West Coast | 2.29 | 2.29 |
| Scottish Islands | 0.00 | 0.00 |
| Onshore E&W | 4.92 | 6.52 |
| Onshore Scotland | 5.75 | 7.22 |
| Scotland | | 11.29 |
| E&W | | 11.02 |

**WACM 2**

| Renewables (GW) | 2020 | 2030 |
|---|---|---|
| Offshore E&W East Coast | 2.43 | 2.48 |
| Offshore E&W South Coast | 3.27 | 3.27 |
| Offshore E&W West Coast | 1.22 | 1.22 |
| Offshore Scotland East Coast | 1.18 | 1.18 |
| Offshore Scotland West Coast | 0.78 | 0.78 |
| Scottish Islands | 0.47 | 0.47 |
| Onshore E&W | 3.69 | 4.92 |
| Onshore Scotland | 6.51 | 9.76 |
| Scotland | | 12.19 |
| E&W | | 11.89 |

*Source: NERA/Imperial*

This is due to lower load factor plant being constructed (Table 9), requiring additional capacity to be built to meet the 2020 renewable target. We understand that NERA/ICL's explanation for this effect is that the ALF element of the WACM2 tariff is relatively lower for wind plant with lower load factors (in positive TNUoS zones). However, we have reviewed the differences in the capacity built by the model under Status Quo and WACM2 and have identified discrepancies which are not explained by changes in TNUoS.

**Table 9 Average load factors of capacity built under SQ and WACM2 (NERA/ICL modelling)** [35]

| | Avg Load Factors | | |
|---|---|---|---|
| | *SQ* | *WACM2* | Δ |
| Onshore | 34% | 31% | 3.70% |
| Offshore | 45% | 41% | 3.97% |

Source: NERA/ICL

Table 10 shows the changes in capacity with a negative indicating a lower value under WACM2. Under WACM2 the lowest cost projects (Scottish Highlands onshore wind with a load factor of 46.9%) are not built in the NERA/ICL modelling. These have an assumed levelised cost of £54.4/MWh under WACM2, lower than the level of £56.3/MWh under Status Quo, and significantly lower than the next onshore or offshore project.

[34] NERA/ICL document submitted to Ofgem: *2nd DRAFT - Slides for Ofgem Meeting.pdf*

[35] NERA/ICL, Sixth Response to Ofgem TransmiT Questions

**Table 10 Wind capacity changes in WACM2 relative to SQ (NERA/ICL modelling)** [36]

| Area * | Levelised Cost (£/MWh) | | | Capacity Delta (Increase Under WACM2, MW) |
|---|---|---|---|---|
| | SQ | WACM2 | No TNUoS** | |
| Firth of Forth | 156.9 | 153.3 | 151.8 | -651.4 |
| Argyll Array | 121.6 | 119.6 | 113.8 | -600.0 |
| North Wales | 73.7 | 74.6 | 75.4 | -520.5 |
| Highlands | 56.3 | 54.5 | 48.9 | -434.6 |
| Highlands | 67.1 | 65.0 | 58.3 | -434.6 |
| North Wales | 70.8 | 71.7 | 72.5 | -165.4 |
| Kintyre | 114.9 | 110.3 | 107.9 | -151.2 |
| Kent & Thames Estuary | 78.3 | 77.8 | 78.3 | -89.2 |
| Lincolnshire | 63.5 | 63.6 | 64.2 | -85.5 |
| Lincolnshire | 74.9 | 75.0 | 75.7 | -85.5 |
| East Anglia | 67.3 | 67.4 | 68.1 | -79.4 |
| East Anglia | 73.7 | 73.7 | 74.5 | -79.4 |
| Northwest England | 64.4 | 64.1 | 64.7 | -77.5 |
| Northwest England | 76.2 | 75.9 | 76.6 | -77.5 |
| Yorkshire | 64.4 | 64.1 | 64.7 | -75.9 |
| Yorkshire | 76.2 | 75.9 | 76.6 | -75.9 |
| North England | 61.4 | 60.5 | 61.0 | -74.8 |
| North England | 79.0 | 77.8 | 78.4 | -74.8 |
| Aberdeenshire | 59.0 | 57.1 | 52.3 | -73.4 |
| Aberdeenshire | 69.0 | 66.9 | 61.2 | -73.4 |
| West Midlands | 70.3 | 70.3 | 71.0 | -71.4 |
| London | 76.1 | 77.0 | 78.3 | -71.4 |
| West Midlands | 72.8 | 72.9 | 73.6 | -71.4 |
| London | 78.2 | 79.0 | 80.4 | -71.4 |
| Devon & Cornwall | 67.9 | 68.5 | 69.6 | -44.1 |
| Devon & Cornwall | 77.3 | 78.0 | 79.3 | -44.1 |
| Wiltshire | 68.8 | 69.3 | 70.1 | -41.6 |
| Wiltshire | 74.1 | 74.7 | 75.5 | -41.6 |
| Argull & Bute | 72.2 | 65.4 | 63.1 | -34.3 |
| Angus & Fife | 66.6 | 61.6 | 59.4 | -10.6 |
| Angus & Fife | 70.5 | 65.3 | 62.9 | -10.6 |
| Angus & Fife | 72.2 | 66.9 | 64.5 | -10.6 |
| Angus & Fife | 76.5 | 70.9 | 68.3 | -10.6 |
| Argull & Bute | 115.8 | 104.8 | 101.1 | 34.3 |
| Neart na Gaoithe | 186.0 | 181.4 | 179.8 | 72.0 |
| Aberdeenshire | 112.4 | 108.8 | 99.6 | 73.4 |
| Dudgeon | 155.1 | 155.2 | 155.8 | 85.2 |
| Westermost Rough | 181.1 | 180.4 | 181.0 | 111.6 |
| Perth & Kinross | 81.8 | 75.3 | 72.1 | 138.4 |
| Perth & Kinross | 93.0 | 85.7 | 82.1 | 138.4 |
| Perth & Kinross | 103.0 | 94.9 | 90.9 | 138.4 |
| Perth & Kinross | 120.0 | 110.5 | 105.9 | 138.4 |
| Humber Gateway | 186.6 | 185.9 | 186.5 | 139.5 |
| Inch Cape | 181.1 | 176.6 | 172.3 | 148.5 |
| Shetlands | 81.5 | 80.2 | 75.1 | 152.6 |
| Borders | 79.5 | 73.1 | 71.2 | 153.0 |
| South Wales | 83.5 | 83.6 | 84.7 | 279.5 |
| South Wales | 95.1 | 95.2 | 96.4 | 279.5 |
| South Wales | 115.5 | 115.6 | 117.0 | 279.5 |
| West of Isle of Wight | 174.8 | 175.1 | 176.1 | 360.0 |
| Beatrice | 178.4 | 176.6 | 168.8 | 368.0 |
| Triton Knoll | 161.6 | 161.7 | 162.3 | 558.0 |
| Borders | 87.3 | 80.4 | 78.3 | 908.8 |
| Borders | 95.5 | 87.8 | 85.5 | 908.8 |
| Borders | 99.9 | 91.9 | 89.6 | 908.8 |

** Some areas may appear more than once in zones where we specify several types of wind capacity that can be developed by the model, e.g. reflecting variation in load factor or seabed depth*
*** Includes local asset charges, i.e. excludes "wider" TNUoS charges.*

Source: NERA/ICL

NERA/ICL have offered the following explanation for this effect:

*[…] "Such results may be down to:*

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

*Given the complexity of the model, it is not possible to observe precisely which of these effects is driving the result. Also, when interpreting the tables and charts showing levelised cost data, it is important to consider that they are simplified, static representations of the costs fed into the model (see above). In particular, the measure of TNUoS shown on the chart is averaged over a number of years, so the data shown provide an approximate measure of the costs actually incurred by generators in our models."*[37]

NERA/ICL have not provided further detail on which constraints are binding. In the absence of additional information, we are not able to validate the reasons for this counterintuitive result. In

[36] NERA/ICL, Sixth Response to Ofgem TransmiT Questions

[37] NERA/ICL, Sixth Response to Ofgem TransmiT Questions

particular the idea that timing would affect the decision does not seem a likely explanation, given that costs are significantly lower than other projects.

In our view, it is not a credible result that under a charging option which reduces TNUoS for onshore wind, the cheapest projects are no longer developed, particularly under the current proposals for allocating CfDs through competitive auctioning for established technologies. Furthermore, we no longer believe that transmission charging will materially affect the proportions of onshore and offshore wind built since CfDs will be allocated through separate funds for established and emerging technologies.

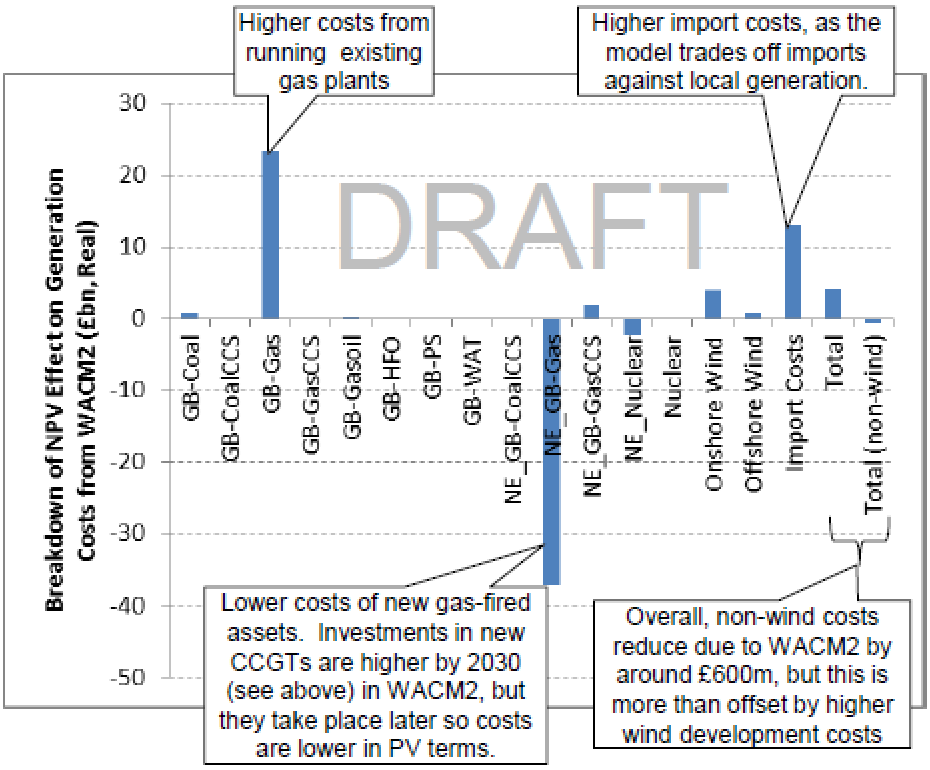
Our estimate based on the levelised costs above suggests that if the 960 MW of the cheapest onshore wind projects did come forward under WACM2 in place of more marginal onshore wind with a levelised cost of £110/MWh, this would reduce the power sector cost difference by over £2.5bn. This is only the most obvious counterintuitive result, of which there are many. For example, under WACM2 Argyll Array decreases in capacity by 600 MW and Inch Cape, West of Isle of Wight and Beatrice all increase in capacity despite significantly higher levelised costs.

NERA/ICL claim that these differences can be explained by the relative changes in TNUoS but this is not a robust justification in our view. Just because a cheaper plant increases in TNUoS does not mean that it should not be built in favour of a more expensive site which has seen a drop in TNUoS.

***Non-wind generation costs***

In the NERA/ICL modelling, non-wind generation costs reduce due to WACM2 by £600m in Net Present Value terms (Figure 7), although the mix between Gas CCGT, Gas CCS and imports changes significantly. This is directionally consistent with our results.

**Figure 7** **Contributions to generation cost changes under WACM2 (NERA/ICL modelling)**[38]




Source: NERA/ICL

***Transmission investment costs, constraint costs and losses***

Transmission investment costs are higher under WACM2 by about £100m/year throughout the period. It is not clear why the costs increase is spread equally throughout the period, rather than diverging over time which we might expect. There is less wind in Scotland by 2020 in under WACM2 so we might expect onshore transmission cost to be lower. However, this may be offset by the costs of OFTOs, due to additional offshore wind capacity.

This is a different result to that observed for NERA/ICL's modelling of Improved ICRP in October 2012, where transmission costs were similar until 2020 and Improved ICRP was higher after this point. We would expect more similarity in results, given the similarities between Improved ICRP and WACM2, and that NERA/ICL have not reported any changes to their modelling approach that we would expect to affect these results.

Constraint costs reduce by £63m under WACM2[39]. On its own this is counter-intuitive. However, the sum of transmission investment costs and constraint cost does increase under WACM2 as we would

[38] NERA/ICL document submitted to Ofgem: *2nd DRAFT - Slides for Ofgem Meeting.pdf*

[39] NERA/ICL have re-stated their constraint costs from the published values to adjust for an inconsistency in the presentation of constraint costs in Table 1.1 of their report.

expect. The increase in transmission losses is directionally consistent with additional Scottish generation capacity by 2030.

***Consumer costs***

In the NERA/ICL modelling, the Capacity Market is modelled as the top up required to increase average prices to a level which compensates generators for 'missing money' which is a result of price spikes being capped below the Value of Lost Load (VoLL). The process is to run the model with prices allowed to spike to the Value of Lost Load at £10,000/MWh. The prices are then capped at £1000/MWh and an average capacity payment over the modelling period is calculated to top up this missing money.

It appears to be the case, therefore, that generation investment decisions are made based on prices spiking to VoLL, and the Capacity Market is then smearing out costs to consumers over the modelling period. This is a theoretical approach which does not reflect the detail of DECC's proposed Capacity Market design (which was not available in October 2012).

In the October 2012 report, the power purchase costs for consumers were based on the sum of the wholesale price and capacity values forecast in the model, which achieves some consistency between generator investment decisions and consumer costs.

For modelling of WACM2, NERA/ICL have presented results based on a revised calculation of wholesale market costs to consumers using the long run cost of new entry, since they viewed that the wholesale prices being generated by the model were not reliable. This removes the link between the revenues that generators base their investment decision on, and outturn prices. It does, however, avoid the complications demonstrated by the Ofgem IA analysis of the effect of volatile capacity margins on wholesale prices.

Despite our concerns surrounding internal consistency, we believe that the revised approach for estimating wholesale price effects has more validity with a Capacity Market in place, since the objective of the Capacity Market is to ensure that the marginal plant recovers its long run marginal costs. The NERA/ICL approach is simplistic since it only considers new CCGT as the price setting plant in the Capacity Market, whereas our updated analysis considers the full range of potentially marginal plant. However, as that analysis shows, we would concur with the NERA/ICL conclusion that WACM2 would likely increase the Capacity Market clearing prices and hence the overall wholesale costs for consumers (although this may be outweighed by savings in CfD costs)

However, we believe that NERA/ICL have overstated the consumer cost impacts. As our analysis presented above shows we believe that there is an offsetting effect in consumer costs from being able to reduce CfD strike prices as a result of lower TNUoS costs. This effect is not captured in the NERA/ICL analysis, and indeed since their modelling shows that more expensive projects would need to be built to meet the targets under WACM2, CfD strike prices would need to be higher on average and not lower.

***2013 and 2014 differences***

There are differences in capacity, generation, carbon emissions, transmission costs and constraint costs in 2013 and 2014. We note that the differences are inconsistent with the argument that implementation should be delayed from 1st April 2014 because existing generators cannot react in this timescale. NERA/ICL have explained that this is because the model is run from 2013, as the model was not updated from the October 2012 set up:

*There are differences between the results in 2013 and 2014 because, when we conducted our original work in October 2012, we assumed that the first year in which the new model could take effect would be 2013, and that generators could change their decisions in response to the new charging model from 2013 onward. The run of the WACM2 model takes the same approach, allowing the methodology to take effect from 2013, to ensure consistency with the previous run of the model.*

NERA/ICL state that for the welfare calculations the net present value uses values from 2015 onwards. Therefore the only impact of the earlier implementation date is if some of the changes dynamically affect the later years. NERA/ICL's view "*Without re-running the models we cannot estimate what this effect would be, but we would expect the effect to be small, as the charges prevailing in the long-term have a much greater weight in the selection of new locations for new entrants and decisions by existing plants to close than tariffs in the first 2-3 years of the modelling horizon".* Whilst it is not possible to check this without further modelling from NERA/ICL, we are satisfied that this is a plausible statement. However the major difference in transmission investment costs occurs by 2014 which would not occur had the modelling start date been later.

***NERA/ICL modelling does not address NERA/ICL's perceived gaps in Ofgem IA analysis***

We note that that the NERA/ICL modelling does not address all the perceived gaps in Ofgem's IA analysis. For example, the NERA/ICL model has not been updated to the 27 generation charging zones, there is no sensitivity modelling, and no distributional analysis has been conducted.

***Summary***

The NERA/ICL analysis suggests a significant increase in power sector costs and costs to consumers associated with WACM2, of order of £6bn on a NPV basis between 2015 and 2030 for power sector costs and £3bn for consumer costs, as shown in Table 11. The differences in costs between Status Quo and WACM2 up to 2020 are similar to those originally modelled by Redpoint when comparing Status Quo and the Socialised approach in the same period i.e. the two most extreme cases modelled. We are sceptical that relatively small changes in transmission charges associated with WACM2 in a system where development projects are highly constrained can yield such significant differences in power sector costs. Furthermore, the differences between NERA/ICL's October 2012 Improved ICRP results to the results for WACM2 are large and not explained. Improved ICRP is a 'fully shared' version of WACM2 and given the similarities we might expect more similar results. NERA/ICL state that the same modelling approach has been used (other than running two more iterations for Status Quo).

**Table 11 NERA/ICL CBA results**[40]

| | 2014-2020 | 2021-2030 | Total |
|---|---|---|---|
| **Impact on Consumers** | | | |
| Power Purchase Costs | 1,484 | 233 | 1,717 |
| Low Carbon Subsidies | | | 269 |
| D-TNUoS | 412 | 357 | 769 |
| Constraints | -49 | -14 | -63 |
| Losses | 268 | 418 | 687 |
| Total | 2,936 | 3,026 | 3,379 |
| | | | |
| **Power Sector Costs** | | | |
| Generation Costs | 1,157 | 2,985 | 4,142 |
| Transmission Investment | 501 | 420 | 922 |
| Constraints | -49 | -14 | -63 |
| Losses | 268 | 418 | 687 |
| Total | 1,877 | 3,810 | 5,688 |

Source: NERA/ICL

We note that the offshore wind results for WACM2 are very different to the results for Improved ICRP from October 2012, which did not show much change in offshore wind build compared to Status Quo.

In summary, their analysis suggests a significant dis-benefit of WACM2 relative to Status Quo. This is in contrast to the results from the National Grid modelling, particularly by the fact the NERA/ICL analysis suggests increases in transmission ***and*** generation costs under WACM2. We believe that this result is counter-intuitive. Most expectations of modelling in this area would be that the impact of WACM2 would be to reduce generation costs and increase transmission costs; if the reduction of generation costs is less than the increase in transmission cost this would suggest that WACM2 was less cost reflective, and vice versa.

Because of the limitations in the assumed approach for allocating subsidies in the NERA/ICL analysis, and the counter-intuitive results it produces, we do not believe that its alternative impact assessment modelling can be relied upon.

## 3.3 Cost reflectivity analysis

This section assesses NERA/ICL's cost reflectivity analysis contained in their IA review and expanded upon in their cost reflectivity report. In their IA review, NERA/ICL define cost reflectivity to mean that the tariff reflects the cost of the marginal transmission investment (the Long Run Marginal Cost, LRMC).

*For a generation TNUoS charging model to be cost reflective, as noted above, it must reflect the costs that TOs incur to accommodate an incremental MW of generation capacity.*

[40] These results are the adjusted values as presented by NERA/ICL to Ofgem and subsequently published on the NERA website. These values take account of the effect that increased wholesale prices under WACM2 lead to decreases in the required low carbon subsidies.

NERA/ICL undertook their analysis using the DTIM model. The full methodology is explained in their cost reflectivity report. Essentially the DTIM model is run twice. For a given generation background it is run to calculate optimal generation dispatch and transmission investment. Generation dispatch is then fixed, and the model re-run to calculate the shadow cost of marginally reducing the amount of generation. From this, the marginal LRMC of transmission expansion caused by different types of generation is computed.

The Investment Cost Related Pricing (ICRP) approach is, however, based on average incremental expansion costs (based on load flow modelling across available transmission assets[41]) and not marginal expansion costs. The ICRP approach is therefore philosophically different from the NERA/ICL definition of cost reflective, before any consideration of whether the dual driver for transmission charging is more reflective of underlying transmission network capacity cost drivers. Furthermore, the ICRP methodology aims to recover the total costs to be recovered, the Maximum Allowed Revenue (MAR), from generators and demand according to a 27%:73% G:D split (by use of a residual tariffs). Hence, it should not be expected that tariffs produced under the ICRP methodology will align to the incremental LRMC of investment (however defined) in absolute terms. More instructive is to compare relative differences in tariffs to relative differences in LRMCs by location or technology. The NERA/ICL definition of cost reflective is consistent with economic theory, and indeed the full IA modelling undertaken by both NERA and Redpoint does reflect the marginal costs of transmission investment. However, this definition of cost reflectivity does not address the issue of equitability and the appropriate allocation of transmission costs to different types of network users. The CMP213 methodology was not intended to challenge the underlying principles of ICRP, but rather to evolve it to reflect better the different drivers of transmission investment. This should be borne in mind when assessing the arguments.

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. Where this is not the case, the tariffs produced by the ICRP methodology may not to be as close a match to the relative LRMCs of new investment.

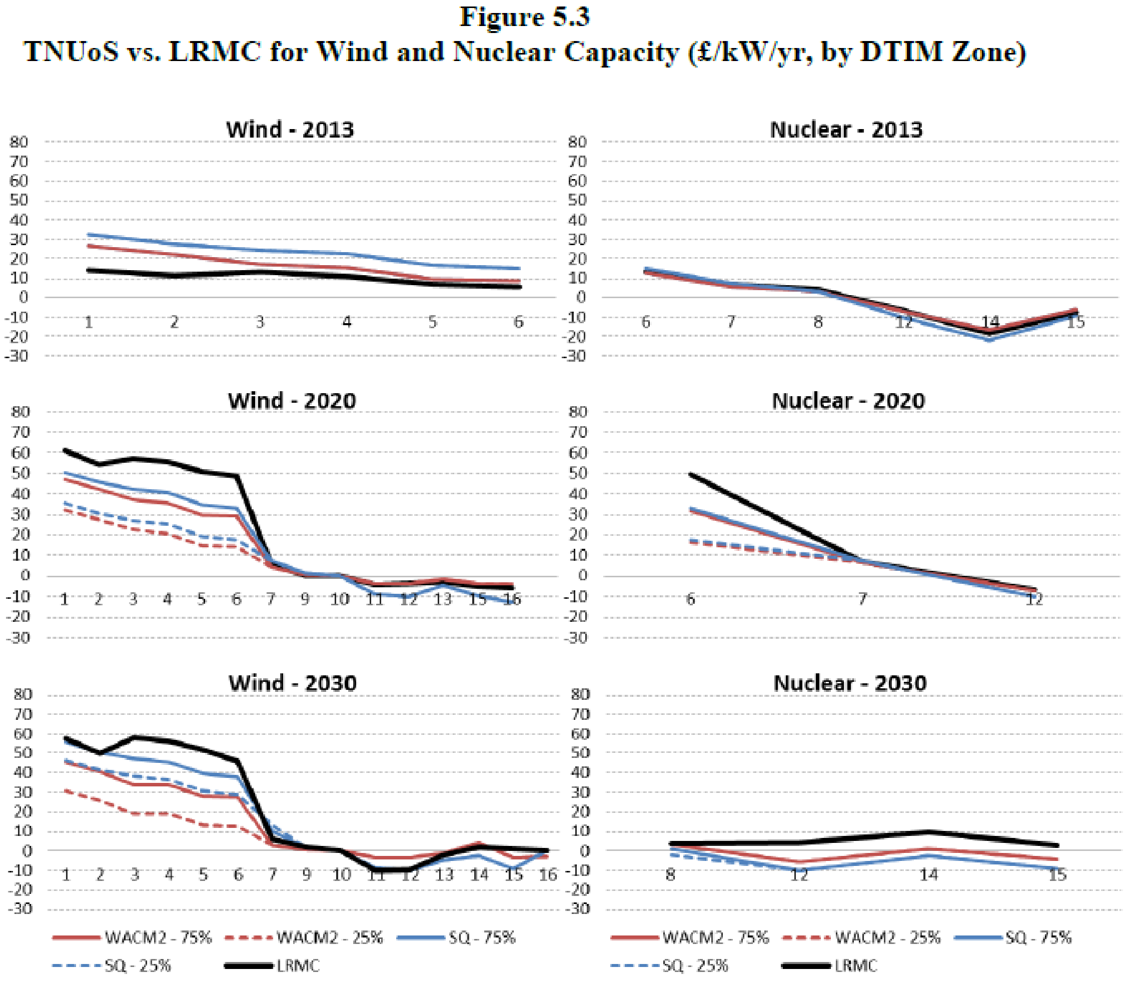
Essentially this is what the NERA/ICL analysis of LRMCs and tariffs produced by Status Quo and WACM2 is demonstrating in some cases. For example, the effect for wind generation is illustrated in Figure 5.3 of their cost reflectivity report and reproduced below. For 2020 and 2030, the two lines (25% and 75%) for each option represent different assumptions on the proportion of flow which will be assigned to HVDC bootstraps in the tariff calculation. Under the arrangements proposed under CMP213 (and modelled in our own analysis), the ratio of flow on the HVDCs is set by a calculation which takes account of the relative capacity of onshore and offshore lines[42]. Given that HVDC bootstraps are an incremental expansion to a larger onshore system, it is likely that in most cases the 25% case is more appropriate.

[41] The methodology is based on linear expansion of existing transmission assets (in the proportions required to accommodate a marginal MW of generation or demand) and removes the 'lumpiness' associated with transmission investments by decoupling charges from the actual investments made.

[42] Page 26 of CMP213 Final Modification Report, http://www.nationalgrid.com/NR/rdonlyres/0E5765AE-2BF5-4B5A-833A-7DFE7AC189F0/61004/FinalReportforAuthority10.pdf

A smaller proportion of assumed flow on the HVDC bootstrap results in smaller tariff differentials due to a smaller fraction of the HVDC expansion cost being used in the calculation of the marginal MWkm for each node.

**Figure 8 NERA/ICL analysis of cost reflectivity for wind and nuclear**



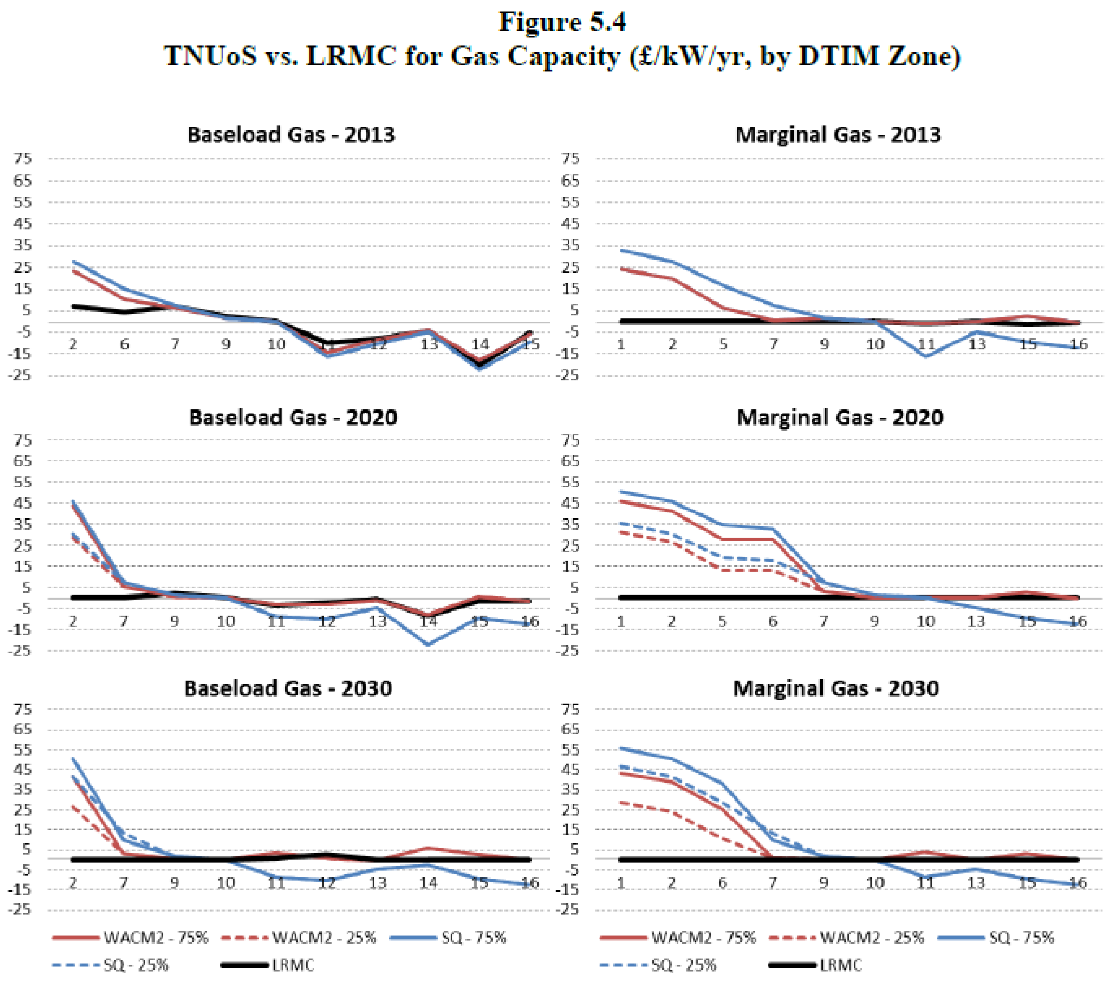

*Source: NERA/Imperial*

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. However, in 2020 and 2030 after HVDC bootstraps are built there is a much greater spread in marginal LRMCs across TNUoS zones, and since the Status Quo methodology produces a slightly higher spread in tariffs across zones than the WACM2 methodology it may be concluded that Status Quo is more reflective of NERA/ICL's measure of marginal LRMC of transmission expansion.

However, the results for other technologies are less clear cut. For example, the results for nuclear, also shown in Figure 5.3 of the report, seem to suggest a slightly better match between marginal LRMCs and tariffs under WACM2 than Status Quo. WACM2 appears to be a closer match to the LRMC in 2013 for the existing nuclear fleet. In 2020 the Scottish nuclear generation in Zone 6 shows the impact of HVDCs is the largest driver of tariffs and the two charging methodologies give similar results. In 2030, by when all nuclear generation is in England & Wales, WACM2 is a closer match.

For baseload gas-fired generation (shown in Figure 5.4 of their cost reflectivity report and reproduced below), Status Quo and WACM2 give similar tariffs and are a good match to marginal LRMC in 2013, except in Scotland. By 2030, the differentials in marginal LRMC have reduced but SQ tariff differentials have not, and WACM2 is a closer match to LRMC.

**Figure 9 NERA/ICL analysis of cost reflectivity for baseload gas and marginal gas**




*Source: NERA/Imperial*

For peaking plant, NERA/ICL's analysis indicates (as shown in Figure 5.4) that peaking generation imposes almost no additional marginal cost (or benefit) on the transmission system. Presumably this is because the transmission capacity is already available for transmission of wind generation. WACM2 has lower differentials in tariffs and therefore is closer to the measure of LRMC.

***Conclusions***

The NERA/ICL analysis on cost reflectivity is a useful addition to the evidence base. It demonstrates that neither transmission charging methodology is particularly reflective of marginal network expansion costs, although this is perhaps not surprising since the ICRP methodology is not based on this principle (rather average expansion costs as explained above). Whilst in some cases, for example wind where HVDC reinforcements are required, Status Quo is (perhaps by coincidence) more reflective of marginal expansion costs, in other cases WACM2 appears more cost reflective. Had HVDC costs been closer to the trend of onshore reinforcement costs[43], we suspect that the NERA/ICL analysis would have demonstrated that WACM2 is more reflective of LRMC in all cases[44].

Hence, even though we believe that there is validity in considering marginal expansion costs rather than average expansion costs assumed under ICRP in an assessment of cost reflectivity, we do not believe that the NERA/ICL analysis demonstrates conclusively that Status Quo is more cost reflective than WACM2. We believe that this is borne out in our IA modelling (which recognises the incremental, or marginal, expansion costs) and yet shows in most cases a small net benefit in reduced power sector costs in the long run under WACM2.

[43] Onshore expansion costs in NERA/ICL's analysis do not include the costs of substations, but it is not clear if the same is true for HVDC bootstraps.

[44] NERA/ICL include a sensitivity in their report which increases further the differential between HVDC costs and onshore AC reinforcement costs. A sensitivity that decreases the differential would be informative.

# 4 Updated analysis

## 4.1 Introduction

We have performed updated analysis of Status Quo and WACM2 to address issues raised by NERA/ICL and Pöyry (Section 2.4), and other consultation respondents, and to reflect the latest EMR proposals. The assumptions and modelling methodology are described in our review of National Grid's modelling of the Ofgem Impact Assessment[45] and in our original modelling report for Project TransmiT[46].

In this section we first describe the changes to the methodology for this analysis. We go on to describe the assumptions for an Original Case and an Alternative Case and present the results for these two core cases. Finally, we present the results of four sensitivities.

## 4.2 Functional and methodological changes

We have made two major changes to the model functionality to reflect the latest policy proposals on the implementation of EMR by DECC. We have updated the modelling of the Capacity Market (CM), and changed the allocation process for CfDs. The net effect of these changes is to reduce the variability in capacity margins and renewables build across runs helping to isolate the effects of changes in transmission charging on power sector costs and consumer bills.

### 4.2.1 Capacity Market

For this analysis we have implemented a change to the representation of the CM in the model. These changes were made to align better the model's CM functionality with DECC's current proposals for the design of the CM.

Bids into the CM by eligible parties are assumed to be on a perfectly competitive cost-recovery basis, whereby any shortfall in the expectation of gross margin of the marginal plant in the CM sets the auction clearing price. In this way, the lowest cost projects available (considering both existing plant and new build) to fulfil the capacity requirement are awarded capacity agreements. The expectation of gross margins are based on a 5 year forward view taking into account expected wholesale market revenues, and expectations of future costs, including TNUoS. Therefore, changes in TNUoS on account of the transmission charging policy can be expected to affect the merit order of plant in the capacity auctions, and therefore impact capacity prices.

From 2019 onwards, the build and retirement decisions of non-CfD plants are assumed to be based entirely on the outcome of capacity auctions; i.e. failure by a plant to receive a capacity agreement will lead to its retirement. Capacity that does not receive an agreement in the first auctions of 2014 (for 2018/2019 delivery) will retire in or before 2018.

[45] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-impact-assessment-cmp213-options

[46] https://www.ofgem.gov.uk/publications-and-updates/modelling-impact-transmission-charging-options-%E2%80%93-report-redpoint-energy

The modelled CM auctions target a fixed 10% de-rated capacity margin (we explain the relationship to DECC's reliability standard in Section 4.3.3). Whilst DECC's proposals include a sloping 'demand curve' for capacity, whereby more capacity will be procured if the marginal capacity is cheaper, for simplicity (and to ensure comparability between SQ and WACM2 capacity mixes) we have assumed a vertical demand curve under which a fixed 10% margin is always targeted[47]. Both the target margin and the de-rating factors used in the Original Case (see Section 4.3) for the purposes of clearing the CM auctions are the same as those used in the original analysis (and therefore do not align exactly with Ofgem/DECC values from the Capacity Assessment).

All plants in the model are represented on a plant basis rather than as individual units. This means that plant are either all-in or all-out of the CM auctions, causing 'lumpiness' which leads to a degree of variability in outturn de-rated capacity margins relative to the target.

### 4.2.2 Approach to CfD allocation

Two changes have been made to the incentives for new renewable build: 1) CfDs are modelled to replace ROs as the incentive regime from an earlier date – 2015 as opposed to 2018, since we believe this better reflects latest DECC policy under which CfDs will be the main mechanism for supporting new low carbon generation from the date of the first CfD allocation; and 2) plant are allocated CfDs on the basis of a constrained competitive allocation framework as opposed to on a first-come-first-serve basis using administrative strike prices.

This change primarily affects onshore and offshore wind build rates, with the model now constrained to limit the maximum annual capacity according to a constrained allocation, with the marginal plant in a given year determining the outturn CfD strike price (separately for onshore and offshore wind). The rate of build of onshore and offshore wind is consistent with DECC's Updated Energy Projections (UEP) capacity mix. Both the Original Case and the Alternative Case match these build rates to 2020. After 2020 in the Original Case, increases in renewable capacity are small, whereas the Alternative Case continues to broadly follow DECC UEP values (see Section 4.3). These changes also improve the tie out with DECC's forecast allocation of support payments between the RO and CfDs in the Levy Control Framework (LCF).

As the model now builds equivalent levels of renewables (on a capacity basis) between each of the two transmission charging policies, the locational differences and impacts on renewables support payments on account of changes to TNUoS are isolated, whereas before differences in the renewables mix were a dominate factor in the power sector cost results.

### 4.2.3 Other changes

The build out of new nuclear and CCS plants is now fixed, rather than being determined endogenously within the model. This change was made with recognition that such projects are most likely to be built on an individual basis under discrete funding decisions, irrespective of the transmission charging policy. What is more, given the high cost of these projects, individual small differences in build can materially affect the outcome of the CBA, and obscure the effects of transmission charging alone.

[47] The modelled CM achieves a minimum margin of 10%, which may lead to an over-estimation of CM costs relative to modelling a sloping demand curve.

### 4.2.4 Limitations

***Legacy TransmiT assumptions***

To ease comparison with the previous analysis most input assumptions have been left unchanged, including:

- Generation and transmission capacity costs;
- The suite of available projects for both generation and transmission[48];
- What specific capacity exists today recognising the model decision framework still commences in 2011; and
- The de-rating factors (as discussed further in Section 4.3.3).

Although new information may have come forward that warrants changing some of these assumptions, they still remain internally consistent and suitable for the purposes of a fair comparison between the two modelled transmission charging policies.

The suite of available transmission projects is based on a finite ex-ante list of projects that are known to be under consideration and projects that would likely come forward over the period of analysis. In the near to medium term, this list is suitable as it is informed by what is currently known about the system. However, in the later years of the model it is possible that additional projects could be developed on a specific needs basis. Such projects would not be captured by the model, so may result in more expensive transmission investment decisions than would occur in practice.

***Uncertainty on EMR policy details***

EMR policies are found to have a significant influence on results and the cost-benefit analysis of the two transmission charging policies. Given this influence, it should be highlighted that not all EMR policy details had been clarified at the time of modelling. Specifically:

- The de-rating factors to be applied to capacity participating in the CM auctions are still unknown. The choice of de-rating factors has commercial implications for the amounts and type of capacity procured.
- The inclusion (or not) of interconnectors or interconnected generation capacity in CM auctions is likely to affect significantly outcomes as the inclusion of interconnectors displaces the need to procure capacity in the GB market. If interconnectors are to be included, to what extent is also unknown. For instance, the de-rating factor for interconnectors and the way in which interconnected capacity could bid into the auction are still open questions.
- How much and what type of capacity is likely to be allocated under CfDs beyond the mid-term time frame (after the first Delivery Plan ends in 2019) is relatively uncertain and also has implications for the CM. This is because CfD capacity contributes to margins, and hence the capacity requirement, but is incentivised completely independently to the CM. As is seen in the modelling of the Alternative Case, the combination of high levels of CfD supported plant, a higher assumption on interconnector de-rating factors and previously awarded 10 year capacity agreements[49] can lead the capacity clearing price falling to zero.
- Whether the CM will continue indefinitely or be a temporary measure.

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48 This includes the assumptions on embedded solar and wind which are not exposed to transmission charges.

49 DECC has since announced that 15 year capacity agreements will available to new capacity

- Although not directly a policy issue, we note that there is uncertainty about the bidding strategies that generators may use, which may diverge from the perfectly competitive cost recovery we have assumed.

## 4.3 Case assumptions

### 4.3.1 Original Case

The Original Case is so named because it draws on the same assumptions used in the Base Case of the National Grid CMP213 Impact Assessment modelling work. The exception to this is with respect to the functional modelling changes outlined above.

### 4.3.2 Alternative Case

The Alternative Case was designed to explore the impacts of WACM2 in a system with an alternative commodity price trajectory and different assumptions on some aspects of EMR. Specifically:

- Lower gas prices, and higher coal prices in the near term, were modelled that improve the economics of gas relative to coal, particularly in the near to medium term (see Figure 10);
- A greater proportion of renewables was assumed after 2020 by broadly following the DECC UEP onshore and offshore wind deployment assumptions to 2030, with correspondingly less CCS and nuclear to achieve a similar power sector carbon intensity of around 100 g/kWh by 2030 (see Table 13); and
- A greater assumed de-rating factor for interconnectors (using a factor of 75%[50]) for the purposes of setting the capacity requirement.

These differences are summarised in Table 12.

[50] The choice of a de-rating factor of 75% represents a case in which the majority of interconnector capacity can be relied upon at times of system stress.

**Table 12 Differences in assumptions between Original and Alternative Case**

| Assumption | Original Case | Alternative Case |
|---|---|---|
| Gas and coal prices | **DECC UEP 2012 assumptions** | **Lower gas price** to reduce CCGT generation costs below that of coal (gas prices are 20% lower than Original in 2015 & 2016, 15% from 2017 to 2020, and 10% after 2020. Coal price increased by 20% in 2015 and 2016) |
| Approach to meeting approximately 100g/kWh carbon intensity in 2030[51] | Nuclear: 15.2 GW<br>CCS: 9.2 GW<br>Onshore wind: 11.9 GW<br>Offshore wind: 10.9 GW | Nuclear: 12.0 GW<br>CCS: 7.0 GW<br>Onshore wind: 14.1 GW<br>Offshore wind: 18.7 GW |
| Interconnector contribution to de-rated margin | **0%** (i.e. interconnectors do not contribute to required capacity in Capacity Market) | **75%** (this represents a case in which the majority of interconnector capacity can be relied upon at times of system stress reducing the capacity requirement accordingly) |

**Figure 10 Short-run marginal cost (SRMC) of thermal generators – Original and Alternative Cases**

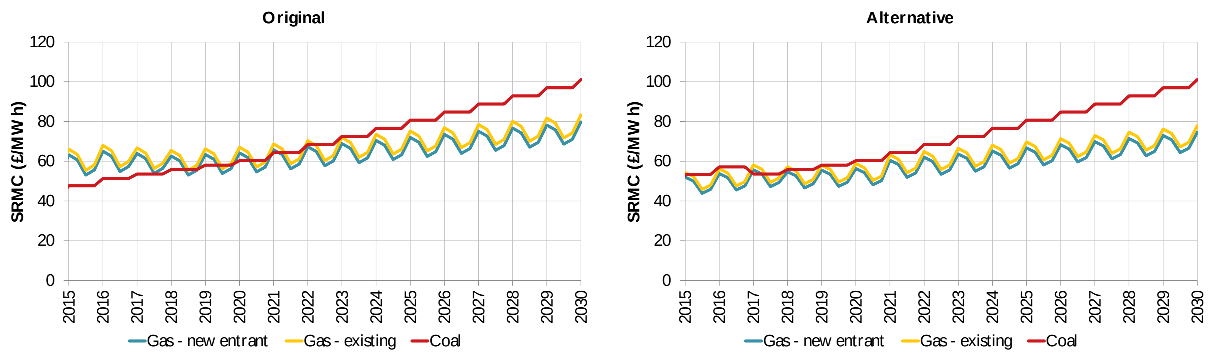



**Table 13 Case comparison: capacity assumptions for low carbon generators, 2030**

| Type | Original Case | Alternative Case |
|---|---|---|
| Onshore wind | 11.9 GW | 14.1 GW |
| Offshore wind | 10.9 GW | 18.7 GW |
| Nuclear | 15.2 GW | 12.0 GW |
| CCS (coal and gas) | 9.3 GW | 7.0 GW |
| Carbon intensity in 2030 | 99 $gCO_2$/kWh | 103 $gCO_2$/kWh |

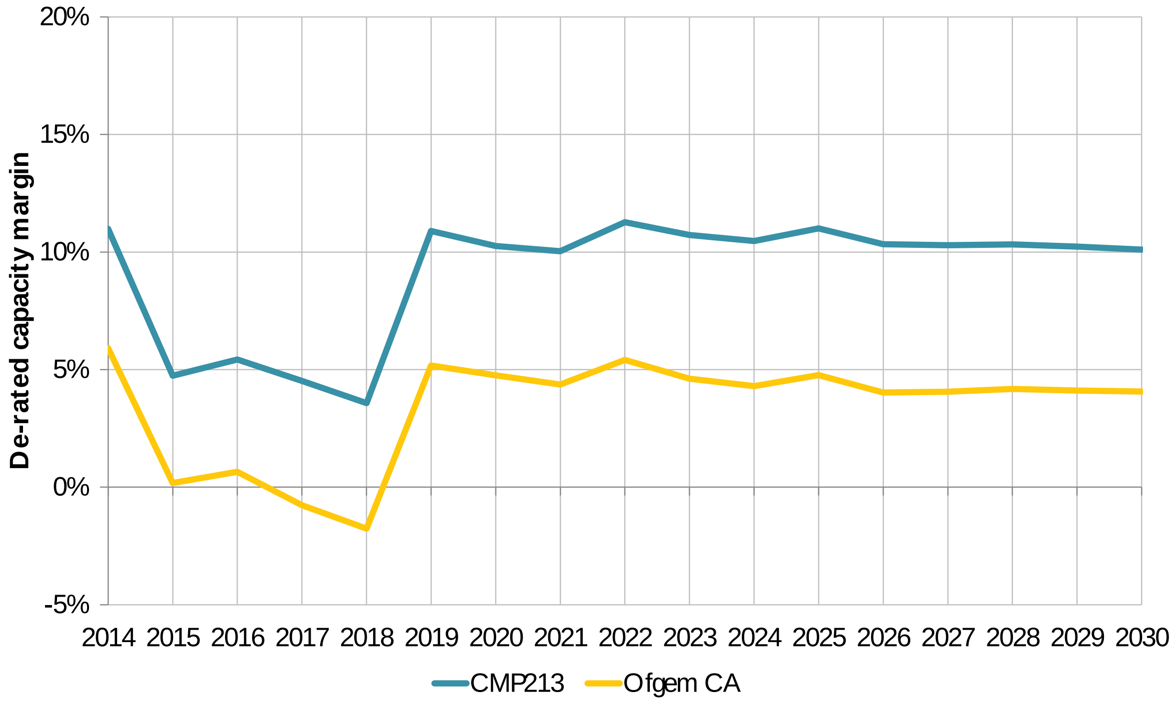
[51] Nuclear and CCS levels in the Original Case were developed by the CMP213 Working Group. In the updated modelling the timing and location of Nuclear and CCS is exogenous to the model. In the Alternative Case, a greater proportion of renewables was assumed after 2020 by broadly following the DECC UEP onshore and offshore wind deployment assumptions to 2030, with correspondingly less CCS and nuclear to achieve a similar power sector carbon intensity of around 100 g/kWh by 2030.

### 4.3.3 De-rating factors and capacity adequacy

The adopted approach to de-rating capacity is of importance in a system supported by a Capacity Market that targets a specific capacity requirement. For a given installed capacity on a system, the reported de-rated capacity margin is a function of: 1) the de-rating factors of generating capacity; and 2) the assumed de-rating factor of interconnectors.

For this analysis, the original set of de-rating factors used in the TransmiT modelling and CMP213 Impact Assessment work have been adopted for consistency with the previous modelling; the exception being a 75% de-rating factor for interconnectors used in the Alternative Case. It is important to note that these de-rating factors differ from those used more recently by Ofgem for its Capacity Assessment (CA) in 2013. To demonstrate the effect of adopting different de-rating factors, Figure 11 shows the evolution of the de-rated capacity margin for the Original Case using de-rating factors from this analysis (CMP213) and de-rating factors from the Ofgem CA 2013[52].

**Figure 11 Effect of de-rating factor assumptions on outturn de-rated capacity margins – Original Case**



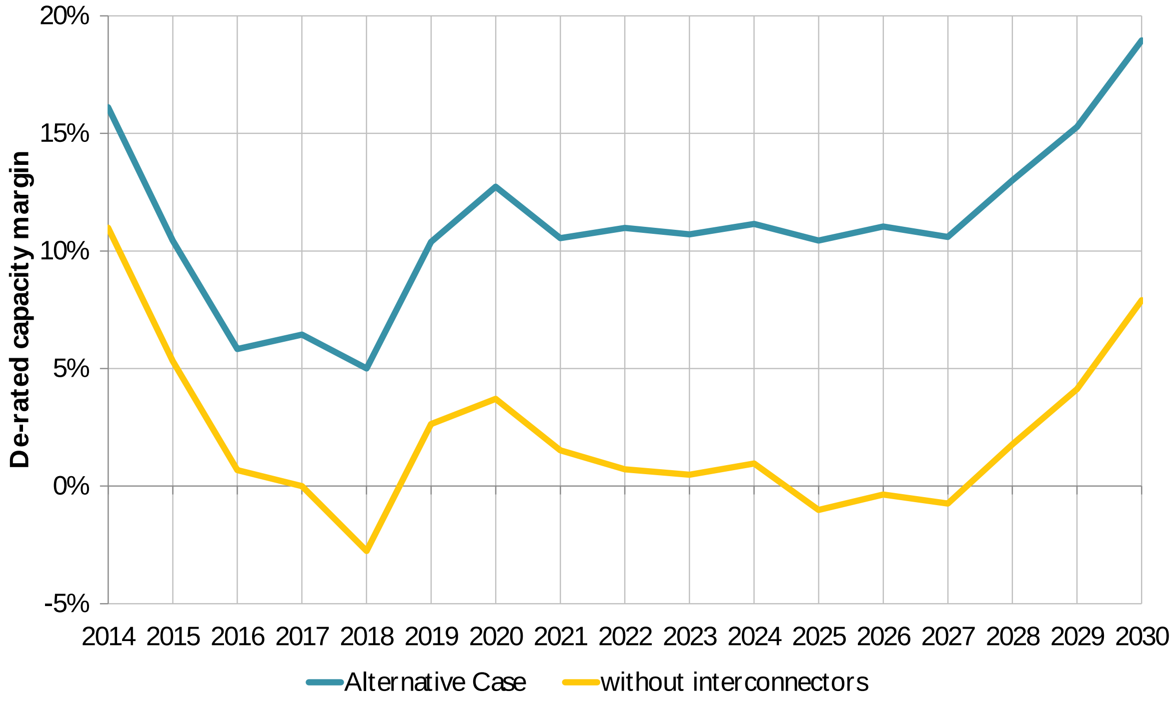

The adopted CMP213 de-rating factors are more optimistic than those used in the Ofgem CA work, and so consistently higher de-rated capacity margin is shown. This is partly due to the assumed export at peak across Irish interconnectors (Moyle and East-West) in the Ofgem CA but also because lower de-rating factors are used for most thermal plants (e.g. 81% for nuclear in Ofgem CA compared to 90% in CMP213). Importantly, however, the margin of 4-5% from 2019 onwards under the Ofgem CA assumptions corresponds approximately to the 3 hours per year Loss Of Load Expectation (LOLE) that DECC is proposing for the reliability standard to assess the capacity

[52] Note that the profile of the outturn de-rated capacity margins for each of the two cases is discussed in Section 4.4.2.

requirement. This suggests that the 10% targeted de-rated capacity margin for this analysis is broadly consistent with the proposed reliability standard.

The impact that interconnectors have on de-rated capacity margins is further demonstrated in Figure 12, which shows Alternative Case margins with and without the contribution from interconnectors (assumed to have a de-rating factor of 75% in this case). With the growing capacity of interconnection to GB, there is a divergence from the outturn de-rated capacity margin and its equivalent without interconnection. This difference indicates the sensitivity of the capacity requirement to assumptions on interconnector de-rating factors. Because changes to TNUoS have varying effects on the costs of generating plant at different parts of the capacity auction bid stack, the assumptions on interconnector de-rating factors turn out to have a significant impact on how WACM2 could affect capacity prices.

**Figure 12 Impact of interconnectors on the de-rated capacity margin of the Alternative Case**




## 4.4 Results

This section describes and explains the comparative changes between Status Quo and WACM2 for the two core cases: the Original Case that retains the assumptions from the National Grid analysis of CMP213 and the Alternative Case with the changed assumptions outlined above.

### 4.4.1 Transmission charges

***Maximum Allowed Revenue (MAR)***

The MAR represents the total amount of revenue collected from market participants to recoup the costs of the transmission networks, split 27% and 73% between generators and demand respectively (the G:D split). As such, where there are differences in network investment between Status Quo and WACM2, these differences will be reflected in the total MAR that must be recovered through generation and demand tariffs. However, as Figure 13 and Figure 14 indicate, there are only small differences in the MAR between the two transmission charging policies for a given case. Therefore, for the most part, differences in tariffs between the two policies are more a reflection of the calculation of the tariff itself than any significant changes in underlying costs that must be recovered.

As discussed further below, total transmission investment is greater in the Alternative Case than the Original Case (reflecting the greater amount of renewables in that case), resulting in the greater overall levels of MAR that must be recovered.

**Figure 13 MAR: Status Quo and WACM2 – Original Case**

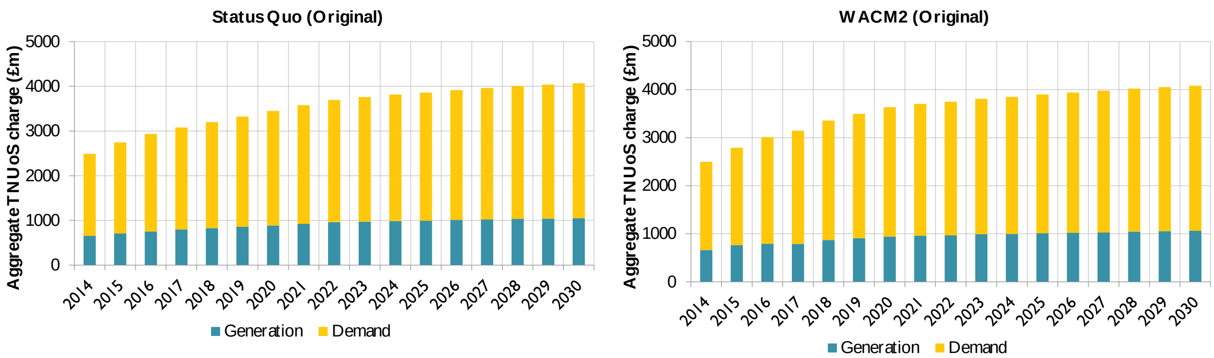
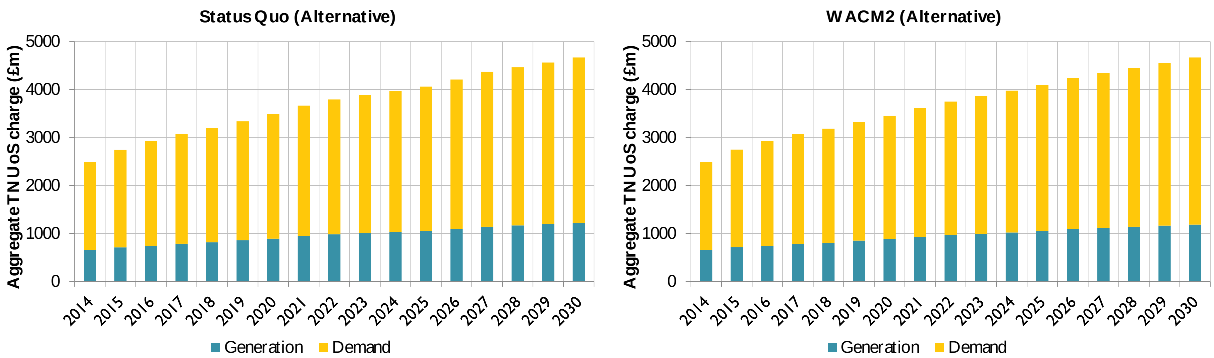



**Figure 14 MAR: Status Quo and WACM2 – Alternative Case**




### *Generation tariffs*

Under WACM2, generation tariffs reduce in northern regions for both high and low load factor generators (see Figure 15 and Figure 16). Particularly in the case of low load factor (30% intermittent) generators, there is a general compression of tariffs, whereby high tariff regions under Status Quo become lower and low tariff regions become higher under WACM2.

These effects are also observed in the Alternative Case (see Figure 17). Individual differences arise on account of investment decisions specific to each case.

**Figure 15 Status Quo and WACM2 generation wider tariffs for selected zones – Original Case**

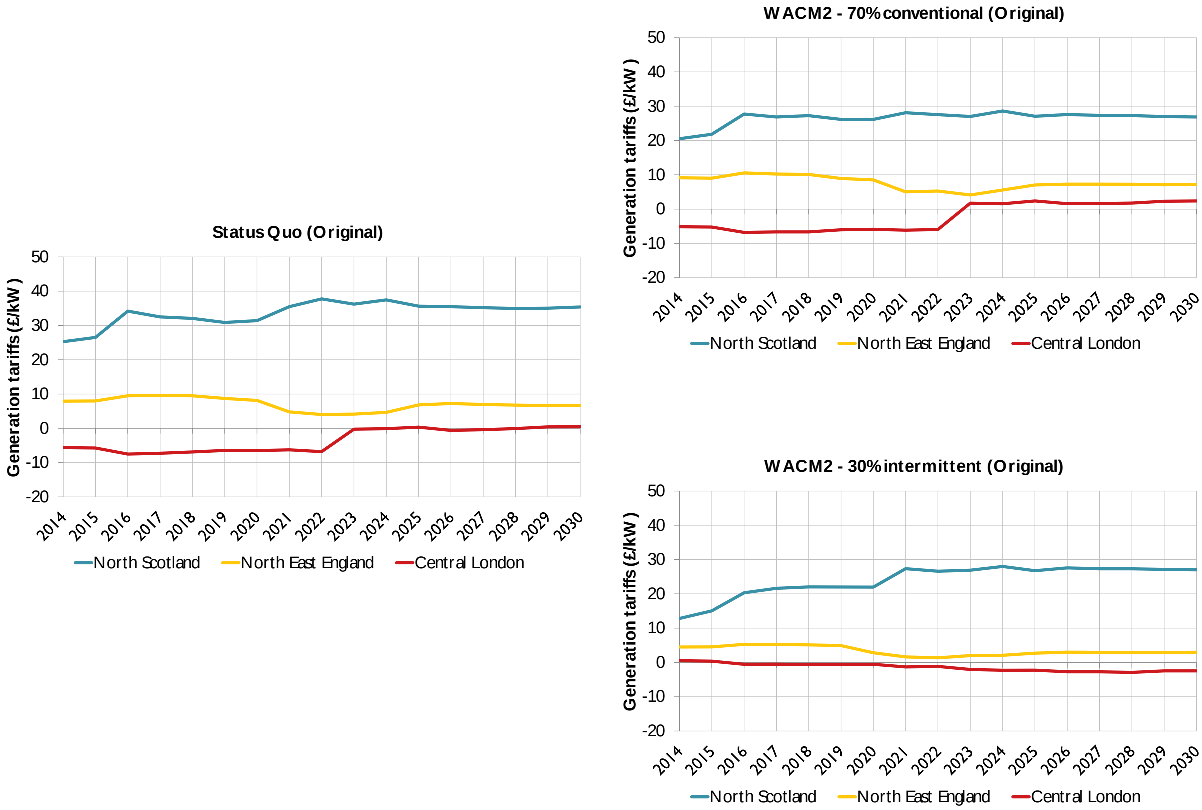



**Figure 16 Generation tariffs, 2014 – sorted according to Status Quo (Original and Alternative Cases)**

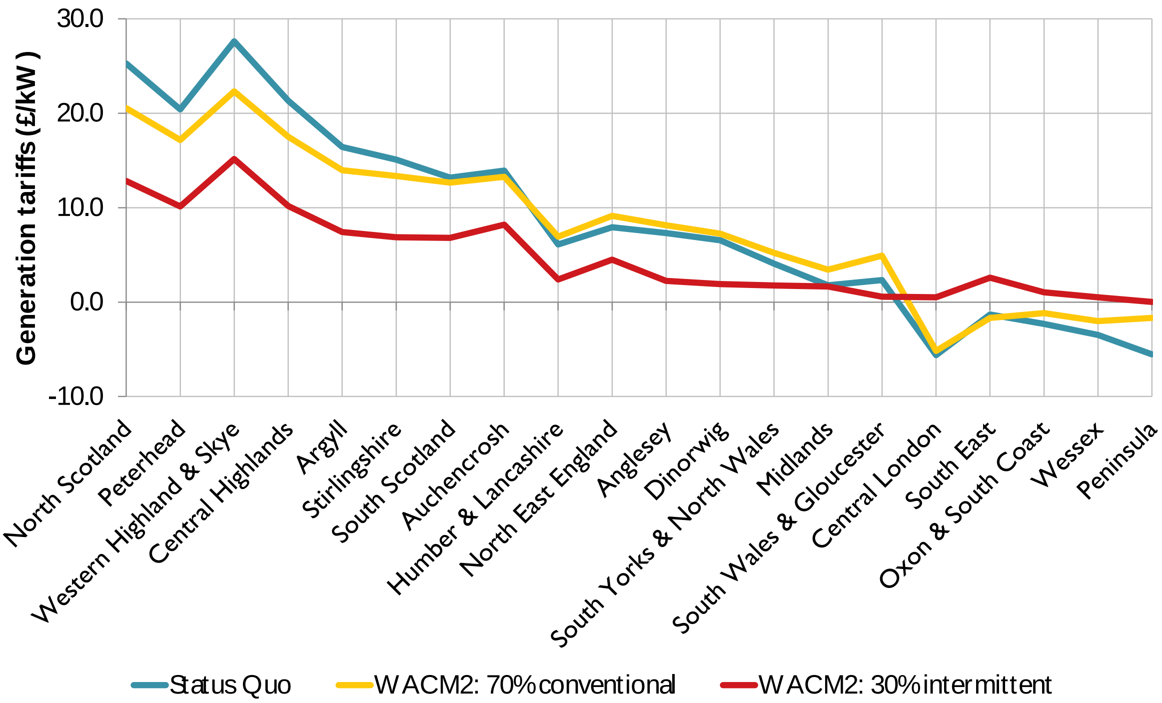
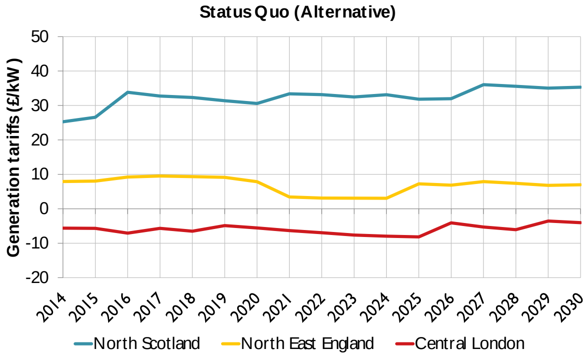
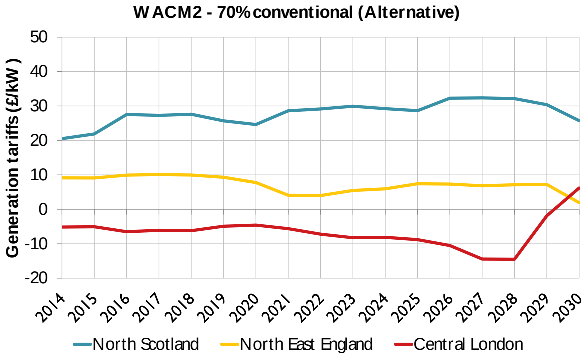
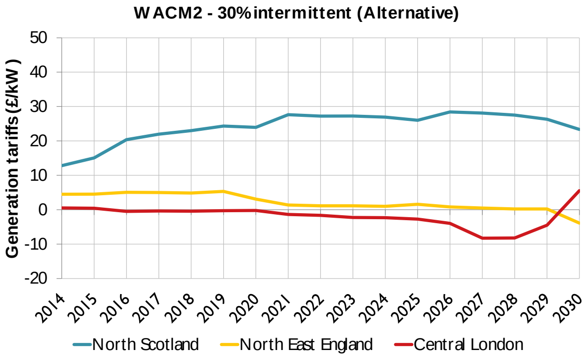


**Figure 17 Status Quo and WACM2 generation wider tariffs for selected zones – Alternative Case**




### 4.4.2 Capacity mix

A key outcome of the modelling is the impact that the transmission charging policy has on the location and type of capacity that the market is likely to deliver. The revised approach to CfD allocation means that locational differences between the two policies are more prominent than differences in the type of renewable capacity delivered.

***Location***

The transmission charging policy has been found to affect materially the siting decisions of new generation capacity. In general, WACM2 has a tendency to migrate capacity north on account of the relative reduction in these tariffs seen in Section 4.4.1, reflecting the greater importance of gas exit charges and wind load factors as locational signals. For example, in 2020 in the Original Case, 1,600MW of new CCGT capacity is preferentially located in North England under WACM2 in place of Midlands and North Wales under Status Quo (see Figure 18). Likewise, approximately 1,400MW of new onshore wind capacity shifts from South Scotland, Midlands and North Wales to North Scotland under WACM2.

By 2030, the location of new CCGT build has broadly evened out between the two policies, with the exception of some CCGT capacity in Midlands and Wales under Status Quo being substituted for an equivalent volume of OCGT capacity in South England and South Wales under WACM2 (see Figure 19).

In the Alternative Case, similar effects are observed, albeit with a greater level of onshore and offshore capacity by 2030.

**Figure 18 New build by location (MW), 2020**

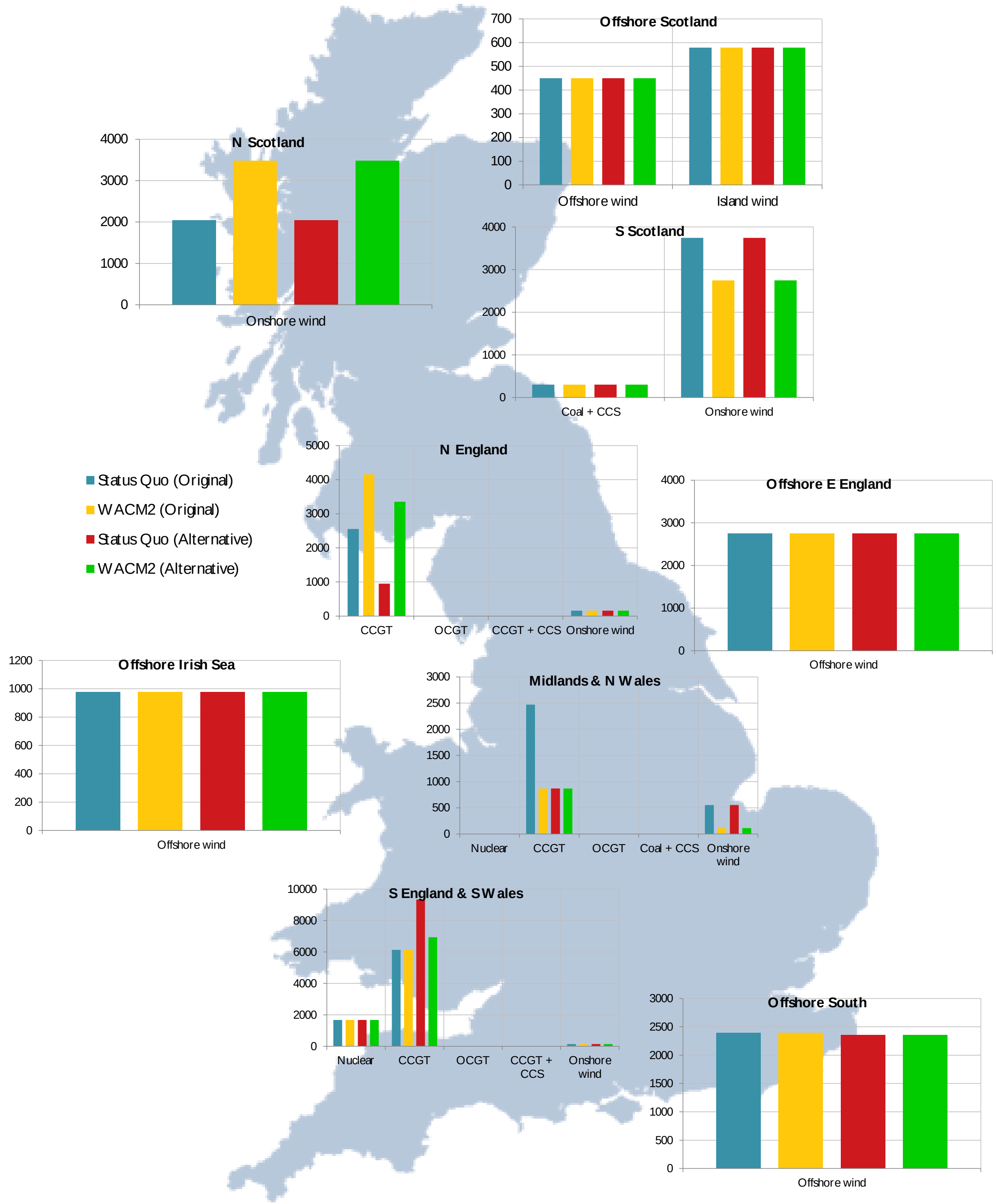
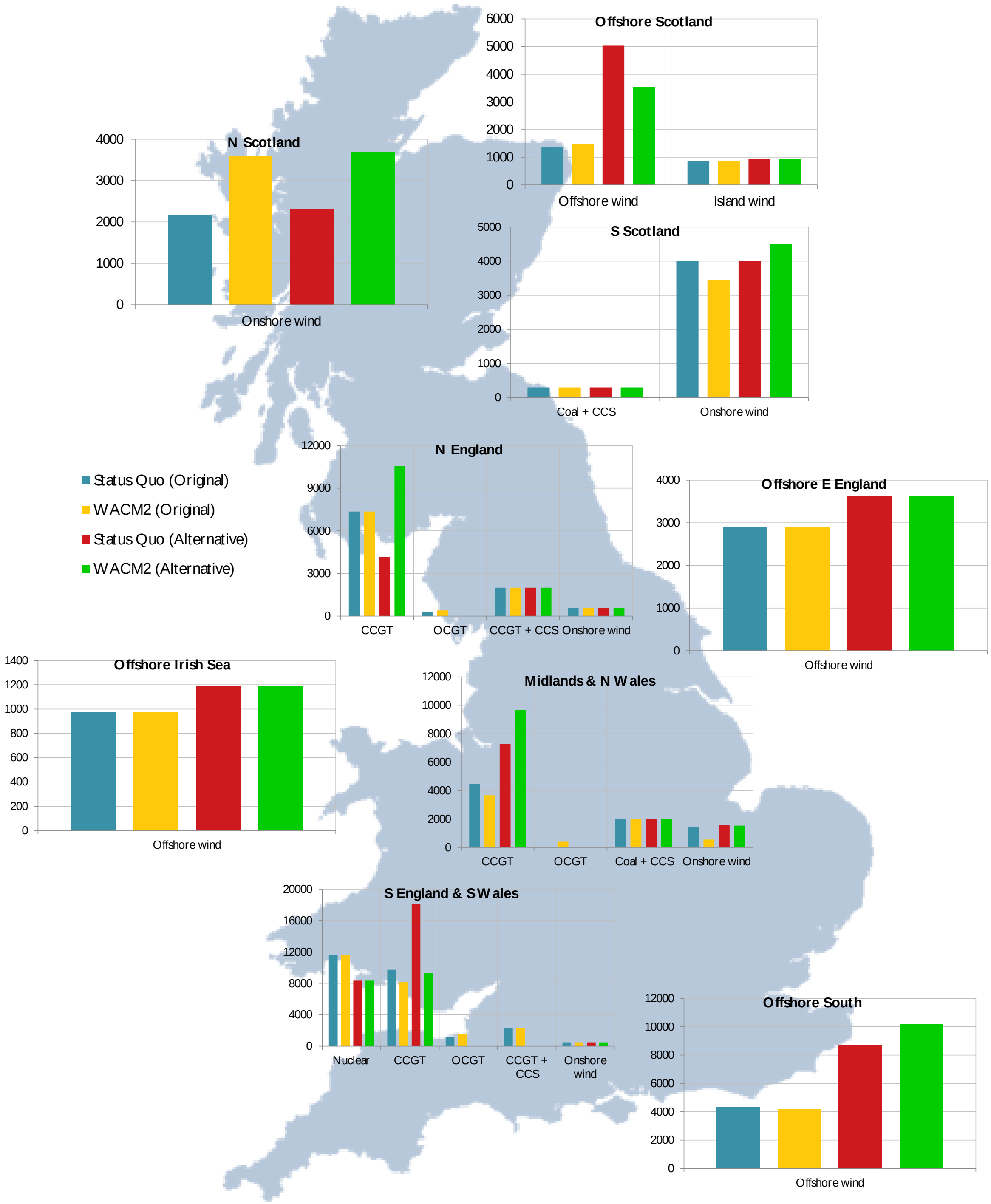


**Figure 19 New build by location (MW), 2030**



### *Capacity type*

Figure 20 indicates the evolution of capacity mix under Status Quo for each case. At an aggregate level, there is little to distinguish between the type of renewable capacity that Status Quo and WACM2 deliver for a given case. This is largely a function of assuming competitive allocation of CfDs within the modelling.

The modelling of the CM allows for some differentiation in thermal capacity. In the Original Case differences emerge between the new build and retirement profiles of thermal plants between the two transmission charging policies. Status Quo develops more new CCGT capacity and retires more existing plant than under WACM2. By 2030 an additional 2,400MW of new CCGT plant is built under Status Quo, within an aggregate difference of CCGT capacity of 800MW. Under WACM2 an additional 800MW of OCGT capacity is built by 2030, in part because of the dependence of tariff on load factor[53].

The Alternative Case on the other hand is identical in its level and type of thermal and renewable capacity between Status Quo and WACM2. This is predominantly due to a greater proportion of total capacity coming through the CfD incentive scheme under which the magnitude and type of capacity brought forward is fixed.

**Figure 20 Generation capacity – Original and Alternative Cases – Status Quo[54]**

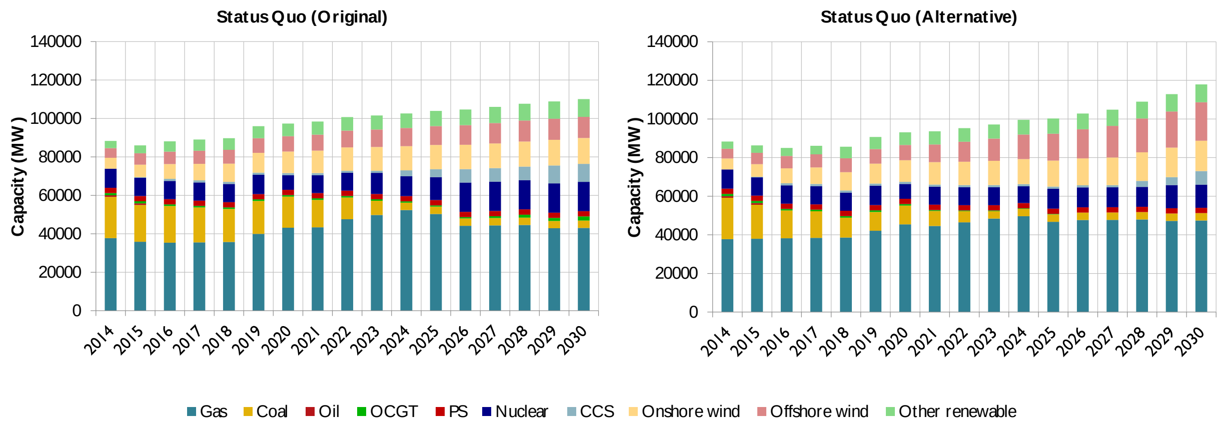


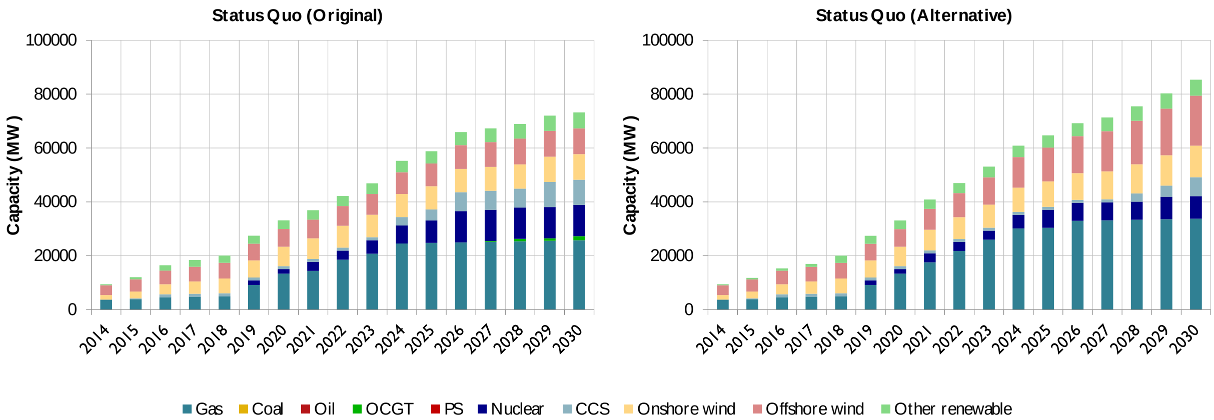

Figure 21 shows the evolution of decisions taken under the CM under Status Quo for each case. All new build activity commences in 2019 (the first CM auction is in 2014 for 2019 delivery), following which new CCGT capacity is built each year until around 2024 at which point most CM new build finishes. The continued deployment of new CfD capacity means that existing thermal capacity continues to be pushed out of merit by new CfD build and forced to retire. This is particularly true in the Alternative Case where greater levels of economic retirements occur to accommodate the larger volume of CfD new build (and the contribution of interconnectors to the capacity requirement). These aggregate differences to the Original Case are most clearly seen in Figure 22.

[53] Under WACM2, a proportion of the tariff (the Year Round Shared element) is related to Annual Load Factor, which is lower for OCGTs.

[54] Only Status Quo is shown here as differences to WACM2 are small in the Original Case and identical in the Alternative Case.

## Figure 21 CM investment and retirement decisions – Original and Alternative Cases – Status Quo

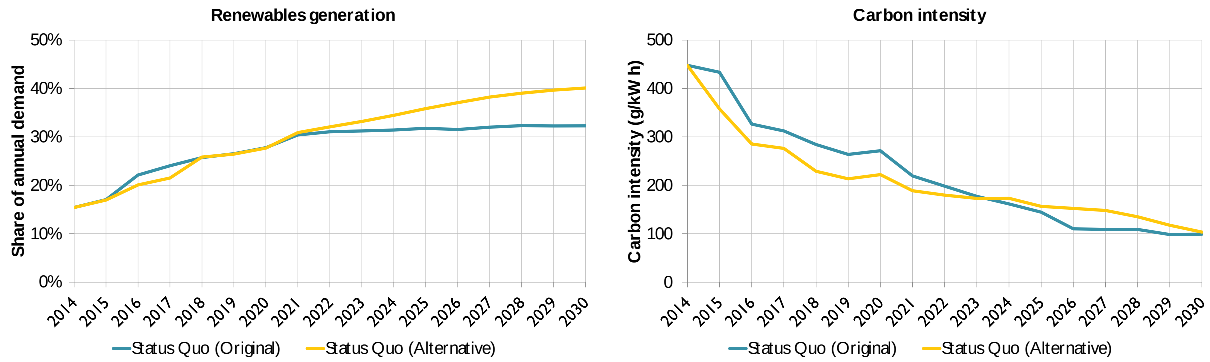

## Figure 22 New build capacity – Original and Alternative Cases – Status Quo




### 4.4.3 Sustainability goals

The Original and Alternative Cases present differing pathways for delivering low carbon generation on the system. As Figure 23 indicates, both cases achieve the target 100g/kWh carbon intensity target by 2030, but with a different share of renewable capacity. As the aggregate capacity between transmission charging policies is broadly equivalent, there is negligible differentiation between the sustainability metrics of Status Quo and WACM2.

**Figure 23 Sustainability metrics – Status Quo**




The Alternative Case delivers far greater volumes of offshore wind by 2030 than the Original Case, at the expense of less nuclear and CCS capacity (as per the Alternative Case assumptions). Table 14 outlines the key differences in capacity mix between the two cases and their impacts on renewable share and carbon intensity (values are shown for Status Quo, but WACM2 is extremely similar). Note that the increased utilisation of gas compared to coal will also affect the carbon intensity target, the effect of which can be seen in the greater near term reduction in emissions in the Alternative Case compared to the Original Case. Similarly, the slightly delayed renewable deployment in the Alternative Case is due to lower wholesale price expectations affecting build decisions made under the Renewables Obligation in 2014.

**Table 14 Carbon intensity and renewable penetration results – Status Quo**

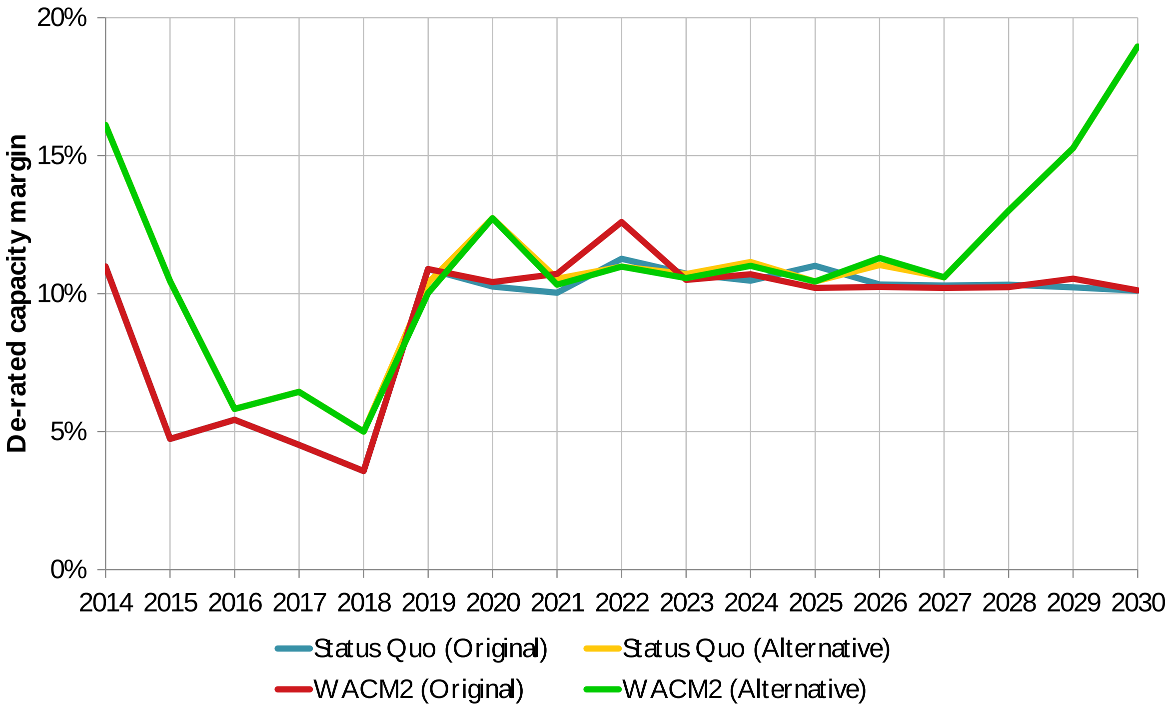
| 2020 results | 2020 | | 2030 | |
|---|---|---|---|---|
| | Original | Alternative | Original | Alternative |
| Onshore wind (GW) | 11.2 | 11.2 | 13.5 | 15.7 |
| Offshore wind (GW) | 8.0 | 7.9 | 11.0 | 19.9 |
| Renewable penetration[55] | 27.8% | 27.7% | 32.3% | 40.1% |
| Nuclear (GW) | 7.6 | 7.6 | 15.2 | 12.0 |
| CCS (GW) | 1.1 | 1.1 | 9.3 | 7.0 |
| Carbon intensity (g/kWh) | 271.3 | 222.0 | 99.2 | 103.3 |

## 4.4.4 De-rated capacity margins

Broadly speaking, the de-rated capacity on the system is equivalent between charging policies across the analysis period for a given case (see Figure 24). This is on account of the stabilising effect that the CM has in targeting a certain level of capacity from its commencement in 2018/2019. Preceding this, there is a period of closures for those plants that would retire anyway or do not successfully compete with existing capacity or new entrants by clearing the CM auctions and covering their costs.

[55] Renewables penetration does not include deployment of small scale FiT generation, which is not included in the analysis

**Figure 24 De-rated capacity margins[56]**




Differences in margins (within a case) can largely be attributed to the plant-level granularity of the CM auction modelling; i.e. a plant is either all-in or all-out of the auction, which in the case of a large plant (up to 2,000 MW) on the margin can contribute to larger de-rated capacity margins than is required[57]. The WACM2 margin in 2022 in the Original Case is one such example. These differences in capacity margin are known to create variation in the consumer cost results because higher capacity margins reduce power prices and wholesale costs.

The reported higher near-term capacity margin under the Alternative Case is due to the higher de-rating factors for interconnectors assumed. The volume of GB generating capacity is equivalent to the Original Case in 2014. The escalation in the Alternative Case margin from 2027 onwards is on account of a combination of the following:

- The higher assumed de-rating factors for interconnectors, and hence lower capacity requirement, results in larger levels of retirement of existing capacity than is observed in the Original Case. By the later years, most capacity on the system is either under CfD contracts or under 10 year capacity agreements; and
- There is an introduction of new large-scale nuclear and CCS capacity under CfD contracts from 2027 onwards resulting in an increase in margin with limited options to replace capacity that is now out-of-merit.

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[56] Note that the Project TransmiT de-rating factors were used for this analysis to achieve a 10% target der-rated capacity margin in the CM. These margins are equivalent to a de-rated capacity margin of about 5% using the Ofgem Capacity Assessment (CA) de-rating factors (see Section 4.3.3).

[57] In practice, CM agreements would likely be awarded on a thermal unit basis, whereby only the necessary portion of a power plant's capacity (rounded up to its individual unit size) is eligible for payments. In the Alternative Case, we applied an ex-post correction in 2023 to keep on only one unit of an existing CCGT online, to remove a single year distortion between SQ and WACM2.

### 4.4.5 Transmission costs

***Transmission reinforcement decisions***

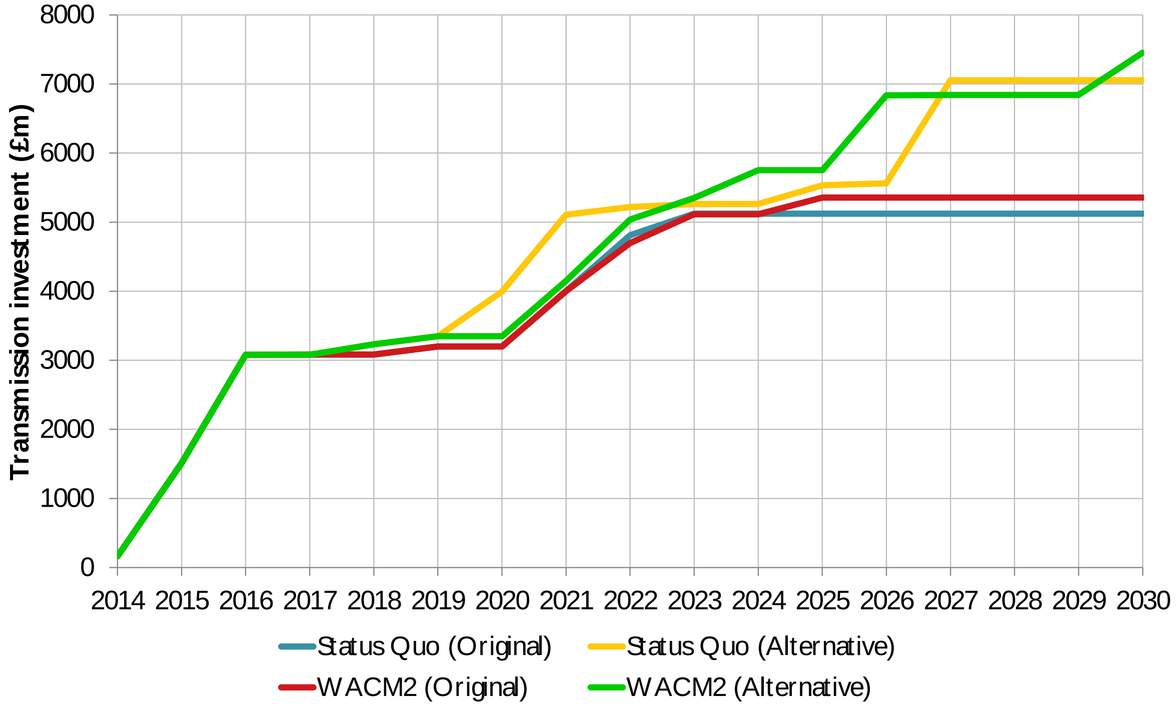
The general migration of generation northwards under WACM2 leads to an increased requirement for transmission reinforcement. Differences in the timing of new HVDC links are the major elements of differences in transmission investment costs. Table 15 indicates that Status Quo and WACM2 are equivalent in the Original Case, with some differences emerging in the Alternative Case only. Specifically, the Western HVDC Link #2 is built one year earlier under WACM2 with Humber-Walpole HVDC also built in the final year of analysis. These earlier reinforcements reflect the locational differences in generation capacity, noting that the timing, magnitude and type of renewable new build between the two transmission charging policies are the same.

**Table 15 Timing of new HVDC links**

| Reinforcement | Capacity (MW) | Boundaries reinforced | Status Quo (Original) | WACM2 (Original) | Status Quo (Alternative) | WACM2 (Alternative) |
|---|---|---|---|---|---|---|
| Western HVDC Link | 2000 | B6, B7a | 2016 | 2016 | 2016 | 2016 |
| Western HVDC Link #2 | 2000 | B6, B7a | - | - | 2027 | 2026 |
| Eastern HVDC Link | 2000 | B2, B4, B5, B6, B7a | - | - | - | - |
| Eastern HVDC Link #2 | 2000 | B2, B4, B5, B6, B7a | 2021 | 2021 | 2021 | 2021 |
| Wylfa-Pembroke 2GW HVDC link | 2000 | B202, NW2 | - | - | - | - |
| Caithness - Moray HVDC | 600 | B1 | - | - | - | - |
| Humber - Walpole HVDC | 2000 | B8, B9, B11, B16 | - | - | - | 2030 |

In addition to changes in HVDC links, some differences in AC transmission investments also occur. Figure 25 shows the total transmission reinforcement costs. Differences become apparent from 2025 onwards in the Original Case and from 2020 onwards in the Alternative Case. For the most part, transmission costs under WACM2 are higher than Status Quo for both cases, particularly in later years. This reflects the need to accommodate the greater northern migration of capacity.

**Figure 25** **Reinforcement costs to the main interconnected transmission system**




***Constraint costs and transmission losses***

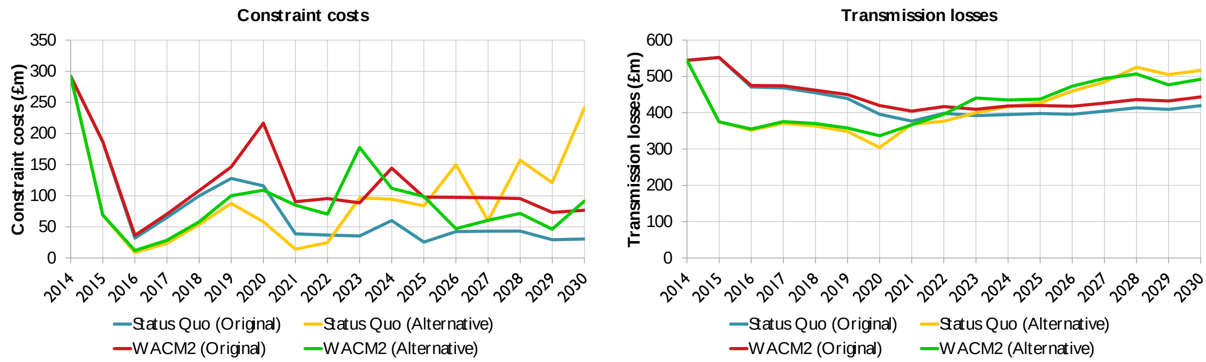
Like transmission investment, constraint costs and transmission losses also reflect the locational differences in generation capacity that occur on account of the transmission charging policy. Typically, generating capacity located further north will result in greater constraint costs (prior to associated transmission reinforcements) and greater transmission losses.

In the Original Case, constraint costs are higher under WACM2 from 2020 onwards (Figure 26). This is caused by the locational differences in both thermal and renewable new build. The large drop in constraint costs in 2021 is primarily on account of the Eastern HVDC Link #2 being commissioned.

Simultaneous effects such as the widespread closure of capacity due to the IED by 2024 and increases in CCGT capacity to replace this differ in their impacts based on where the new capacity is located (typically further north under WACM2).

The Alternative Case exhibits lower constraint costs and transmission losses up to 2020 because thermal generation comes more from CCGTs in the south (due to lower gas prices). The higher transmission losses in later years are a result of the greater levels of renewables. For instance, the build of more offshore wind in Scotland under Status Quo contributes to the increasing profile of constraint costs.

**Figure 26 Constraint costs and transmission losses**



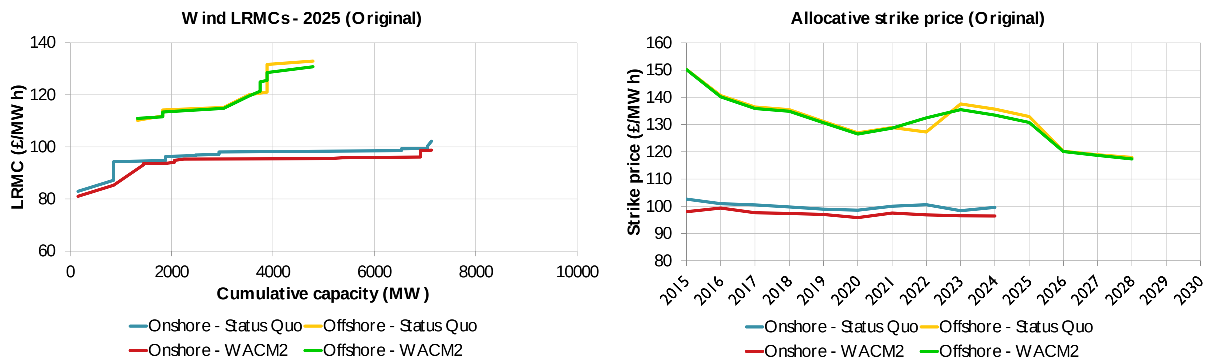

### 4.4.6 Low carbon support

The level of low carbon support in any given year reflects two factors[58]:

- The outturn strike prices of CfDs (particularly onshore and offshore wind); and
- Prevailing electricity wholesale costs, whereby higher costs reduce difference payments required under CfDs such that low carbon support is reduced.

The first of these factors is directly influenced by the transmission charging policy to the extent that a change in TNUoS will impact a plant's LRMC and therefore the CfD strike price required to cover its costs. Figure 27 and Figure 28 indicate the onshore and offshore wind LRMC merit orders (for available projects) for a sample year, and the outturn strike prices based on the marginal plant in a competitive auction for the Original and Alternative Cases respectively. These figures reveal that there is more consistent differentiation in LRMC along the merit order between transmission charging policies among the potential onshore wind plants than the offshore wind plants. This feeds into the more consistent differences in outturn CfD strike prices observed, with WACM2 lower than Status Quo across all years and in both cases. Offshore wind on the other hand does not exhibit the same differentiation in strike prices until later years, when a greater volume of capacity has been built and merit order differences on account of the transmission charging policy begin to affect CfD clearing prices.

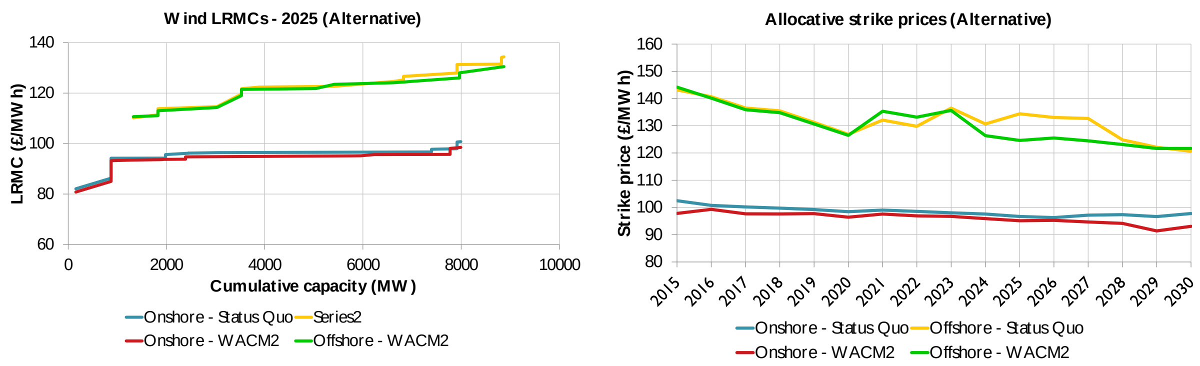
**Figure 27 Wind LRMCs (in 2025) for built capacity and outturn strike prices – Original Case**




[58] Note that in the modelling we proxy constrained CfD Budgets with maximum build levels in capacity terms. In reality a reduction in required strike prices could make more budget available for additional low carbon capacity.

From 2020 onwards, much greater volumes of wind (particularly offshore) are built under the Alternative Case compared to the Original Case. This accounts for the consistently higher outturn strike prices observed and the greater differentiation between transmission charging policies.

**Figure 28 Wind LRMCs (in 2025) for built capacity and outturn strike prices – Alternative Case**




In addition to TNUoS, other factors that affect the outturn CfD strike prices include:

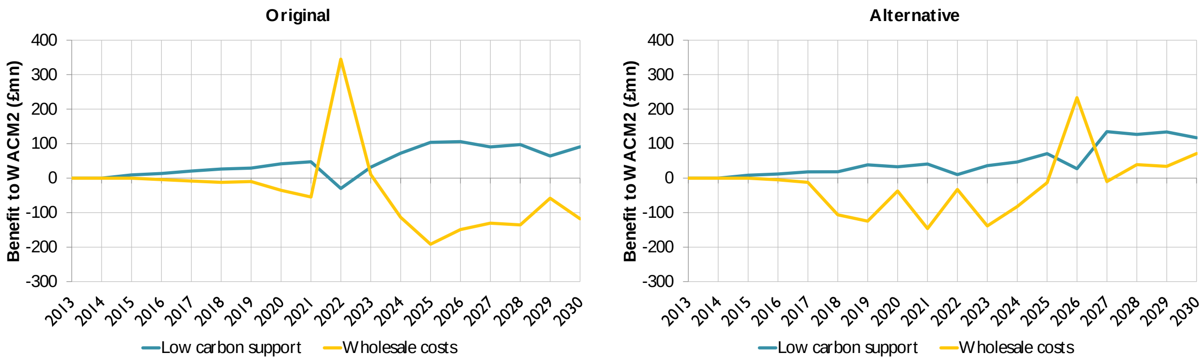
- Differences in the load factor of the marginal plant (particularly true when comparing southern onshore wind to northern onshore wind); and
- The portfolio of available plants to be built in any given year, where locational differences in new build in previous years affect options in subsequent years.

The second primary driver of low carbon support – the wholesale price effect – has a stronger link to differences in thermal build decisions between the two policies than renewable build decisions. This is because the total volume of renewable build is fixed (in capacity terms). By contrast, differences in new CCGT and OCGT build (in the Original Case) and the economic retirement decisions of existing plants (in both cases) on account of the transmission charging policy will impact the capacity mix (see Section 4.4.2). This in turn affects wholesale prices in two ways:

- A different plant type or vintage (with different thermal efficiency) may be on the margin; and
- Wholesale prices are sensitive to differences in the capacity margin on the system.

The influence that prevailing wholesale prices have on the level of low carbon support can be seen in Figure 29. In both cases, wholesale prices are typically higher under WACM2 than Status Quo. When combined with lower outturn strike prices, we observe near consistently lower levels of low carbon support under WACM2. This figure also highlights the impacts of some volatility in wholesale prices under Status Quo on low carbon support (due to capacity margin differences).

**Figure 29 Interaction between low carbon support and wholesale prices**

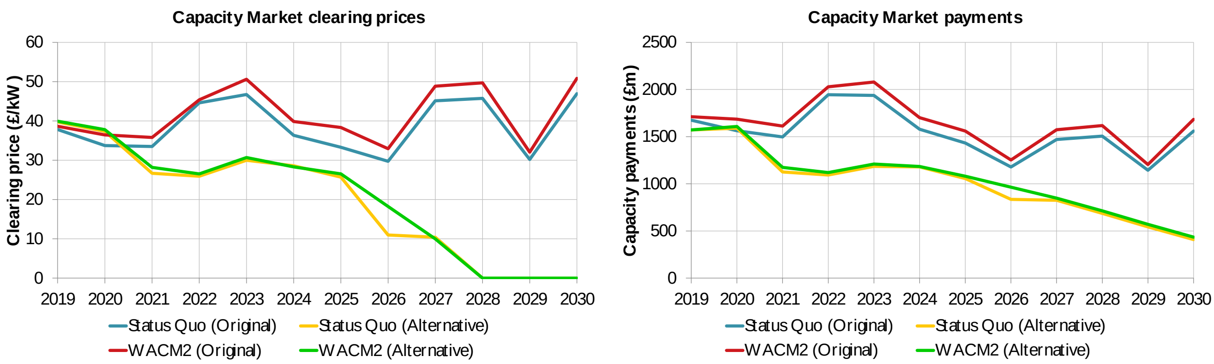



## 4.4.7 Capacity payments

As outlined in Section 4.2.1, CM auctions are modelled to clear on a competitive cost-recovery basis. As such, differences in costs incurred by the marginal capacity in the auctions will feed through into differences in CM auction clearing prices. As TNUoS is among the fixed costs, the transmission charging policy, all other things being equal, will have an impact on capacity prices.

Figure 30 indicates the CM auction clearing prices and the subsequent payments to generators under both policies and for both cases across the period of analysis[59]. For the most part, capacity prices are higher under WACM2 than Status Quo. This is particularly true in the Original Case. In the Alternative Case, the clearing price collapses to zero from 2028 onwards, since most plant is supported by CfDs or long term capacity agreements by this stage. This also corresponds with an increase in the de-rated capacity margin (see Section 4.4.2).

**Figure 30 Capacity Market clearing prices and payments**




The marginal plant in the CM auctions is typically located in a region of higher TNUoS under WACM2 (see Table 16). As the volumes of qualifying CM capacity are broadly equivalent between the two policies, this is driving the increase in capacity payments seen.

Table 16 outlines the interaction between location, type, TNUoS and clearing price for the marginal plant that clears the CM auction for each year. The marginal plant under WACM2 has higher TNUoS

[59] The shapes of CM clearing prices and payments do not track each other perfectly for two reasons: 1) all new plant receives 10 year capacity agreements at the clearing price of the original auction; and 2) the volume of capacity that is eligible for the CM changes year-on-year.

than the marginal plant under Status Quo in all but one year. This additional TNUoS that must be recovered is reflected in the marginal plant's capacity payment bid and therefore the clearing price[60].

**Table 16 Marginal Capacity Market clearing plants – Original Case**

| Year | Status Quo | | | | WACM2 | | | | Differences | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Type | Location | TNUoS | CM price | Type | Location | TNUoS | CM price | TNUoS | CM price |
| 2019 | Coal | N England | 6.0 | 37.8 | Coal | N England | 5.7 | 38.6 | -0.4 | 0.8 |
| 2020 | CCGT | S England & S Wales | 0.0 | 33.7 | CCGT | S England & S Wales | 0.0 | 36.4 | 0.0 | 2.7 |
| 2021 | CCGT | S England & S Wales | 1.4 | 33.4 | New CCGT | S England & S Wales | -0.3 | 35.8 | -1.6 | 2.3 |
| 2022 | Coal | S England & S Wales | 1.2 | 44.5 | Coal | Midlands & N Wales | 3.5 | 45.3 | 2.3 | 0.8 |
| 2023 | New CCGT | Midlands & N Wales | 1.8 | 46.7 | Coal | Midlands & N Wales | 3.7 | 50.5 | 1.9 | 3.9 |
| 2024 | New CCGT | S England & S Wales | 1.5 | 36.3 | New CCGT | Midlands & N Wales | 2.8 | 39.8 | 1.3 | 3.5 |
| 2025 | CCGT | S England & S Wales | 1.5 | 33.3 | CCGT | S England & S Wales | 5.7 | 38.3 | 4.2 | 5.0 |
| 2026 | CCGT | S England & S Wales | -1.7 | 29.7 | CCGT | S England & S Wales | 6.5 | 32.9 | 8.2 | 3.2 |
| 2027 | New OCGT | S England & S Wales | -2.0 | 45.1 | New OCGT | N England | 2.8 | 48.8 | 4.8 | 3.7 |
| 2028 | New OCGT | S England & S Wales | -1.0 | 45.7 | New OCGT | Midlands & N Wales | 3.4 | 49.7 | 4.4 | 3.9 |
| 2029 | CCGT | S England & S Wales | -0.8 | 30.2 | CCGT | S England & S Wales | 1.1 | 32.0 | 1.9 | 1.8 |
| 2030 | New OCGT | N England | 1.1 | 46.9 | New OCGT | S England & S Wales | 2.7 | 50.8 | 1.5 | 3.9 |
| | | **Averages** | **0.8** | **38.6** | | | **3.1** | **41.6** | **2.4** | **3.0** |

Although other factors such as the prevailing capacity mix (and therefore wholesale prices) will affect the magnitude of any deficit that must be recovered by the marginal plant through the CM, taking the average across all years, we see that the average difference in TNUoS of the marginal plant corresponds closely with the average difference in CM clearing price between the two policies.

These average differences are smaller in the Alternative Case than the Original Case. In the Alternative Case we do not observe the consistently higher TNUoS of the marginal CM plant under WACM2 that we do in the Original Case (see Table 17). The magnitude of these average differences in CM auction outcomes has a significant impact on the overall consumer costs impact of WACM2 (see Section 4.4.8).

[60] As CM auctions are cleared several years in advance, it is in fact the expectation of TNUoS (as opposed to outturn) that is reflected in a plant's CM auction bid. Therefore, where the same plant is on the margin in each transmission charging policy, the difference in CM clearing price is not necessarily the same as the difference in outturn TNUoS. Changes in the prevailing capacity mix (and therefore dispatch) will also drive differences here.

**Table 17 Marginal Capacity Market clearing plants – Alternative Case**

| Year | Status Quo | | | | WACM2 | | | | Differences | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Type | Location | TNUoS | CM price | Type | Location | TNUoS | CM price | TNUoS | CM price |
| 2019 | CCGT | N England | 6.7 | 39.7 | CCGT | N England | 5.4 | 39.9 | -1.4 | 0.2 |
| 2020 | Coal | Midlands & N Wales | 2.7 | 37.3 | Coal | Midlands & N Wales | 4.1 | 37.7 | 1.3 | 0.4 |
| 2021 | OCGT | S England & S Wales | 0.0 | 26.7 | OCGT | N England | 4.2 | 28.2 | 4.2 | 1.5 |
| 2022 | CCGT | S England & S Wales | -2.5 | 25.9 | CCGT | S England & S Wales | -3.2 | 26.5 | -0.7 | 0.6 |
| 2023 | CCGT | S England & S Wales | -3.5 | 30.0 | CCGT | S England & S Wales | -1.8 | 30.7 | 1.7 | 0.7 |
| 2024 | CCGT | Midlands & N Wales | 0.6 | 28.6 | CCGT | S England & S Wales | -3.4 | 28.3 | -4.1 | -0.3 |
| 2025 | CCGT | N England | 3.9 | 25.7 | CCGT | N England | 4.4 | 26.5 | 0.4 | 0.8 |
| 2026 | New CCGT | S England & S Wales | -0.2 | 11.0 | New CCGT | N England | 4.4 | 18.2 | 4.6 | 7.3 |
| 2027 | CCGT | N England | 8.2 | 10.4 | CCGT | N England | 4.3 | 10.0 | -3.8 | -0.4 |
| | | **Averages** | **1.8** | **26.1** | | | **2.0** | **27.3** | **0.3** | **1.2** |

## 4.4.8 Cost Benefit Analysis

Table 18 shows the Cost Benefit Analysis for the two cases. Overall, the change in power sector costs under WACM2 is a small dis-benefit in the period to 2020 under both the Original Case (-£115m) and the Alternative Case (-£31m). After 2020, both cases demonstrate a net benefit, of £184m and £99m respectively. These differences are much smaller than in the National Grid modelling for Ofgem's Impact Assessment, reflecting the fact that differences in renewables build have been eliminated with the enhanced modelling approach. These cost differences are now entirely related to the location of plant on the system.

The changes in consumer costs relative to the underlying changes in power sector costs are driven by two offsetting effects. Under WACM2, the levelised cost of the marginal CfD strike price setting onshore wind and offshore wind plant reduces, which creates a saving for consumers. On the other hand, the typically higher charges faced by the marginal thermal capacity in the Capacity Market (an effect correctly identified in the NERA/ICL report) increase costs for consumers. The net result depends on the marginal impact on prices, and the volumes of capacity which are exposed to the changing price.

Under the Original Case assumptions, the Capacity Market effect outweighs the CfD effect (due mainly to a larger volume of capacity receiving CM payments than CfD payments), leading to a net cost to consumers of -£115m up to 2020, and -£884m between 2021-2030, despite the lower power sector costs. Under the Alternative Case assumptions, overall CM payments are lower (since less GB capacity is required to meet the capacity requirement) and the difference between Status Quo and WACM2 capacity price is reduced since the auctions are typically clearing on plant which are less affected by the changing transmission charges. Overall, there is a small disbenefit to consumers in the 2011-2020 period and a small benefit to consumers in the 2021-2030 period, reflective of the underlying changes in power sector costs.

**Table 18 Cost Benefit Analysis**

| WACM2 benefit relative to Status Quo NPV (£m) | | Original Case | | Alternative Case | |
|---|---|---|---|---|---|
| | | 2011-20 | 2021-30 | 2011-20 | 2021-30 |
| **Power sector costs** | Generation costs | 18 | 607 | 19 | 102 |
| | Transmission costs | -38 | -169 | 0 | -86 |
| | Constraint costs | -99 | -339 | -55 | 69 |
| | Carbon costs | 4 | 85 | 5 | 14 |
| | **Decrease in power sector costs** | **-115** | **184** | **-31** | **99** |
| | | | | | |
| **Consumer bills** | Wholesale costs | -51 | -308 | -212 | -65 |
| | Capacity payments | -114 | -630 | -13 | -213 |
| | BSUoS | -50 | -169 | -27 | 34 |
| | Transmission losses | -38 | -131 | -41 | -31 |
| | Demand TNUoS charges | 0 | -28 | 30 | -40 |
| | Low carbon support | 106 | 382 | 97 | 417 |
| | **Decrease in consumer bills** | **-147** | **-884** | **-167** | **102** |

### 4.4.9 Sensitivities

We have modelled the following additional discrete sensitivities on the Original Case:

- High Renewable Energy Share (RES);
- Lower Gas Price;
- Low Carbon Price; and
- 7% Target De-rated Capacity Margin.

This section outlines the assumptions used for each sensitivity, and the resulting impacts on the CBA. Further details of the sensitivity modelling results can be found in Section A.

***High Renewable Energy Share (RES) assumptions***

A High RES Sensitivity on the Original Case was modelled using the same renewables capacity as in the Alternative Case. See Table 13 in Section 4.3.2 for a summary of the differences in low carbon capacity to the Original Case. The period to 2020 is identical to the Original Case.

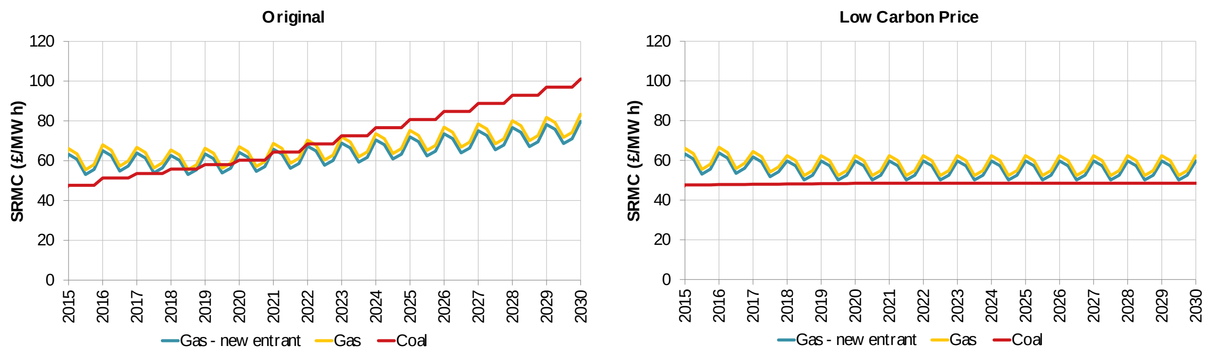
***Lower Gas Price assumptions***

A Lower Gas Price Sensitivity on the Original Case was modelled using the same lower gas price trajectory assumed in the Alternative Case. Specifically, gas prices were adjusted down from 2015 onwards, thus improving the economics of gas generators compared to coal (see Figure 10 in Section 4.3.2). In the early years (2015-16), coal prices were also adjusted upward, with all prices in the modelled period 2011-14 the same as in the Original Case. It is primarily in the near to mid-term where differences in merit order effects are anticipated on account of lower gas and higher coal prices.

***Low Carbon Price assumptions***

A Low Carbon Price Sensitivity was developed to assess the impacts of a lower Carbon Price Floor (CPF) trajectory. This was run in anticipation of the Carbon Price Support (CPS) being frozen at the proposed 2015/16 level of £18.08/t $CO_2$ rather than increasing in line with the targeted CPF trajectory. Carbon prices were therefore assumed to cap at the 2015/16 level, thus also assuming no increase in the underlying EUA price in real terms. The lower carbon prices reverse the trend seen in the Original Case that the economics of gas are consistently better than coal from around 2022 onwards (see Figure 31).

**Figure 31 Short-run marginal cost (SRMC) of thermal generators – Original Case and Low Carbon Price Sensitivity**




***7% Target De-rated Capacity Margin assumptions***

A sensitivity was developed to assess the impact on the Original Case of a lower targeted de-rated capacity margin by 3 percentage points, to 7%. Note that for this sensitivity de-rating factors for interconnectors are assumed to be at 0%. Hence, this sensitivity represents a lower capacity requirement from GB generators than the Original Case but a higher requirement than the Alternative Case.

***Impact of sensitivities on Cost Benefit Analysis***

Table 19 and Table 20 show the Cost Benefit Analysis for the core cases and sensitivities for the periods 2011-20 and 2021-30 respectively.

**Table 19 Cost Benefit Analysis – 2011-20**

| WACM2 benefit relative to Status Quo NPV (£m) | | Original | Alternative | High RES | Lower Gas Price | Low Carbon Price | 7% Target De-rated Capacity Margin |
|---|---|---|---|---|---|---|---|
| Power sector costs | Generation costs | 18 | 19 | 18 | -55 | 30 | 33 |
| | Transmission costs | -38 | 0 | -38 | -14 | -36 | -32 |
| | Constraint costs | -99 | -55 | -99 | -71 | -66 | -99 |
| | Carbon costs | 4 | 5 | 4 | 23 | 2 | 4 |
| | **Decrease in power sector costs** | **-115** | **-31** | **-115** | **-116** | **-70** | **-94** |
| | | | | | | | |
| Consumer bills | Wholesale costs | -51 | -212 | -51 | -265 | -363 | -164 |
| | Capacity payments | -114 | -13 | -114 | -214 | -31 | -75 |
| | BSUoS | -50 | -27 | -50 | -35 | -33 | -49 |
| | Transmission losses | -38 | -41 | -38 | -38 | -24 | -38 |
| | Demand TNUoS charges | 0 | 30 | 0 | 17 | -9 | 4 |
| | Low carbon support | 106 | 97 | 106 | 59 | 134 | 122 |
| | **Decrease in consumer bills** | **-147** | **-167** | **-147** | **-476** | **-325** | **-200** |

**Table 20 Cost Benefit Analysis – 2021-30**

| WACM2 benefit relative to Status Quo NPV (£m) | | Original | Alternative | High RES | Lower Gas Price | Low Carbon Price | 7% Target De-rated Capacity Margin |
|---|---|---|---|---|---|---|---|
| Power sector costs | Generation costs | 607 | 102 | 241 | 36 | 71 | 574 |
| | Transmission costs | -169 | -86 | -349 | -175 | -195 | -103 |
| | Constraint costs | -339 | 69 | -115 | -105 | -30 | -120 |
| | Carbon costs | 85 | 14 | 27 | 27 | 6 | 62 |
| | **Decrease in power sector costs** | **184** | **99** | **-196** | **-217** | **-148** | **413** |
| | | | | | | | |
| Consumer bills | Wholesale costs | -308 | -65 | -351 | 365 | -296 | -178 |
| | Capacity payments | -630 | -213 | -197 | -199 | -10 | -319 |
| | BSUoS | -169 | 34 | -57 | -52 | -15 | -60 |
| | Transmission losses | -131 | -31 | -155 | -114 | -89 | -104 |
| | Demand TNUoS charges | -28 | -40 | -142 | -45 | -77 | 1 |
| | Low carbon support | 382 | 417 | 571 | 176 | 288 | 244 |
| | **Decrease in consumer bills** | **-884** | **102** | **-331** | **132** | **-200** | **-416** |

All the sensitivities exhibit the same pattern of reducing generation costs and increasing transmission costs under WACM2. Whether the net effect on power sector costs is a benefit or dis-benefit reflects the differences in drivers in each case. Likewise the impact on consumer bills may be positive or negative, particularly driven by the impact of WACM2 on the CM clearing prices and wholesale costs.

In the period 2021-30, the Original Case shows the greatest benefit under WACM2 in terms of reducing generation costs. This is primarily due to the greatest differentiation in locational build decisions in the Original Case compared to the other runs. The large thermal replacement (i.e. retirement followed by new build) in the Lower Gas Price and Low Carbon Price sensitivities reduce differentiation somewhat. So too does the larger renewable build out of the Alternative and High RES cases, where the availability of project options (and differentiation) becomes increasingly limited.

The High RES Sensitivity exhibits the same interaction between low carbon support and capacity payments identified in the Alternative Case. That is, the greater proportion of renewables on the system increases the importance of lower CfD clearing prices under WACM2 and simultaneously reduces both the volume procured through the CM and its clearing prices, thereby reducing the negative impact of WACM2 on capacity prices. The extent of this interaction in the High RES Sensitivity is not large enough to record a net benefit to consumers however, primarily due to the continuation of a large dis-benefit in wholesale costs and an increase in demand TNUoS charges. It can be concluded from the High RES Sensitivity, that the consumer benefits of WACM2 increase with a greater renewable energy share through the savings on CfD costs and the reduction in capacity payments.

The 7% Target De-rated Capacity Margin Sensitivity further emphasises the significant impact that CM auction outcomes can have on the costs and benefits of the transmission charging policies. The lower target margin reduces the demand for and therefore the cost of procuring capacity through the CM. Like the Alternative Case and High RES Sensitivity, the lower volumes reduce the significance of the typically higher CM clearing prices under WACM2.

The sensitivity modelling indicates that both power sector costs and consumer bill impacts are relatively sensitive to the set of assumptions used; the range in power sector cost across the sensitivities in the period 2021-30 is £630m and for consumer costs is £1,016m. Policy decisions on levels of renewables, capacity requirement in the CM and the CPF will affect how WACM2 impacts the market.

# 5 Conclusions

***Key issues raised by NERA and Pöyry***

Both the NERA/ICL and Pöyry studies challenge whether the WACM2 approach is reflective of underlying costs, but neither clearly demonstrate that the Status Quo is more cost reflective, or identify alternatives.

Based on the evidence considered, we conclude 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. The exception is if the marginal transmission investment diverges significantly from the mean trend in investment costs over a sustained period. Overall, we do not believe that the NERA/ICL analysis demonstrates conclusively that Status Quo is more cost reflective than WACM2.

***Review of NERA/ICL quantitative analysis***

In our view, the NERA/ICL analysis does not produce credible results. Under a charging option which reduces TNUoS for onshore wind, the cheapest projects are no longer developed, particularly under the current proposals for allocating Contracts for Differences (CfDs) through competitive auctioning for established technologies. Furthermore, we no longer believe that transmission charging will materially affect the proportions of onshore and offshore wind built since CfDs will be allocated through separate funds for established and emerging technologies. Hence, suggesting that WACM2 will increase costs by bringing on more offshore wind at the expense of onshore wind is not valid. Because of the limitations in the assumed approach for allocating subsidies in the NERA/ICL analysis, and the counter-intuitive results it produces, we do not believe that its alternative impact assessment modelling can be relied upon.

***Further analysis of costs and benefits of WACM2 relative to Status Quo***

Our updated analysis confirms that transmission costs are likely to increase, but generation costs reduce under WACM2. However, by eliminating differences in total volumes and type of renewables build, and differences in capacity margins, the updated analysis suggests that the differences relating purely to changing transmission charging are much smaller than previously assumed.

In the longer run, the analysis suggests in the core cases a small reduction in overall power sector costs since the savings in generation costs are likely to outweigh the higher transmission costs. The sensitivity analysis suggests that power sector costs could increase under WACM2 under certain circumstances. Were onshore transmission reinforcements available rather than more expensive HVDC bootstraps we expect that the savings demonstrated under WACM2 would be greater.

Whether consumers are able to benefit from potential reductions in power sector costs under WACM2 will critically depend on the impact of changing transmission charges on CfD and CM auction clearing prices. Depending on final aspects of EMR design, the way in which market participants respond to the new mechanisms, and future development of low carbon technologies, there is a risk that consumers could pay more under WACM2 despite reductions in underlying power sector costs. Although there is significant uncertainty, we would expect the overall impact on consumers of WACM2 would be small in the context of the costs of EMR.

# A Additional results

## A.1 Sensitivity results

***High Renewable Energy Share (RES)***

The High RES Sensitivity extends the locational difference trends seen in the Original Case, with a tendency to migrate capacity north under WACM2. This is particularly true of onshore wind and new CCGT capacity. Offshore wind differences are less distinct however for two reasons: 1) with a more rapid build rate, there are fewer available sites to create optionality; and 2) there is no variation in the assumed load factors of offshore wind projects, which limits the potential for the load factor relationship of WACM2 tariff determination to create locational signals. Overall levels of new build are greater in the High RES Sensitivity compared to the Original Case, to accommodate for substitution of new nuclear and CCS capacity for low load factor wind.

Like the Alternative Case, the High RES Sensitivity benefits from the lower CfD strike prices of WACM2 to a greater extent than in the Original Case due to the greater volumes of CfD capacity. Thus, as expected, levels of low carbon support are higher than in the Original Case, but the difference between Status Quo and WACM2 is greater. Higher wholesale costs under WACM2 also contribute to this low carbon support benefit.

**Figure 32 Generation capacity – Original Case and High RES Sensitivity**

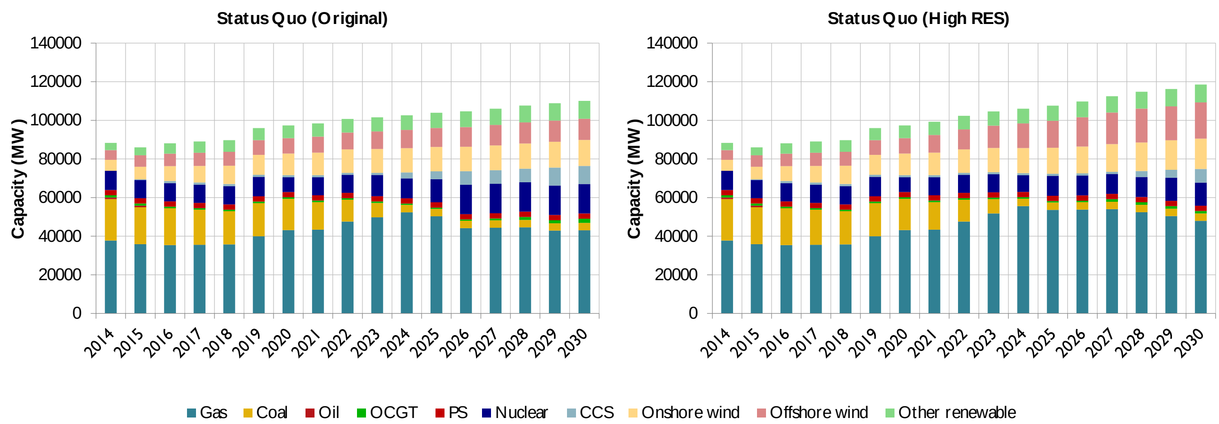


**Figure 33 De-rated capacity margins – High RES**

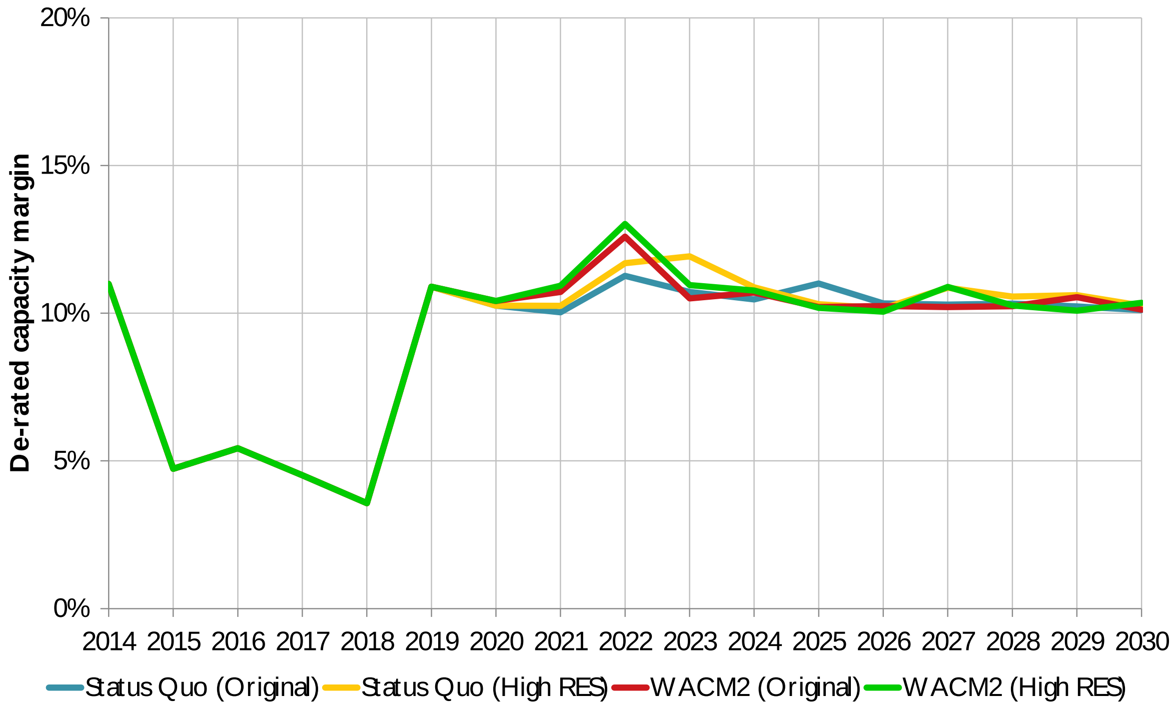
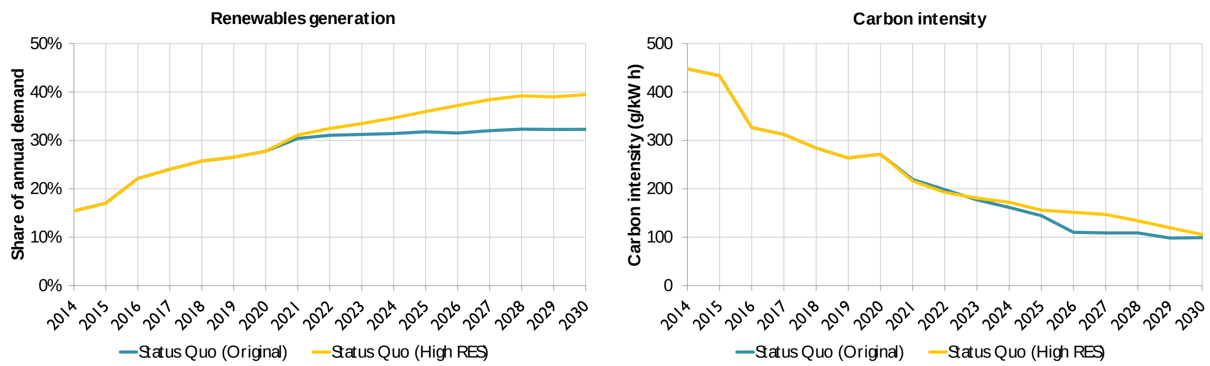



**Figure 34 Sustainability metrics – High RES**




Transmission costs, constraint costs and transmission losses are all higher in the High RES Sensitivity to accommodate the greater share of northern capacity, particularly onshore and offshore wind. The primary difference in HVDC investment to the Original Case comes from the commissioning of the Western HVDC Link #2 in 2027 and 2025 under Status Quo and WACM2 respectively.

**Figure 35 Reinforcement costs to the main interconnected transmission system – High RES**

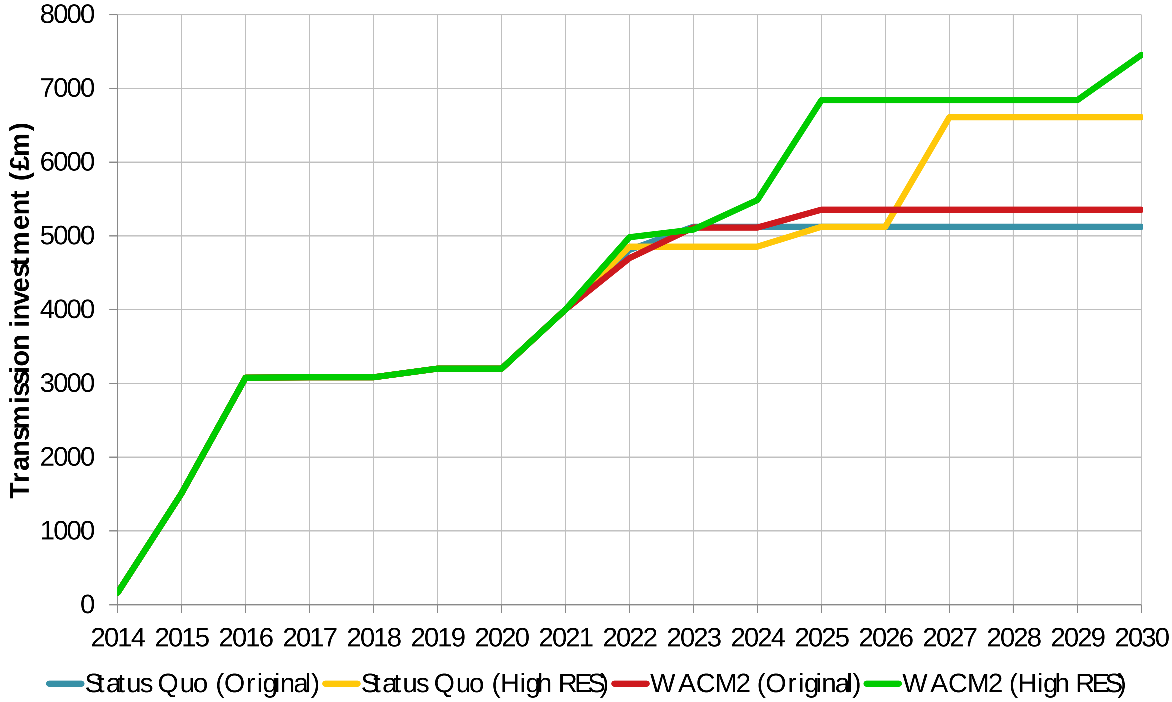
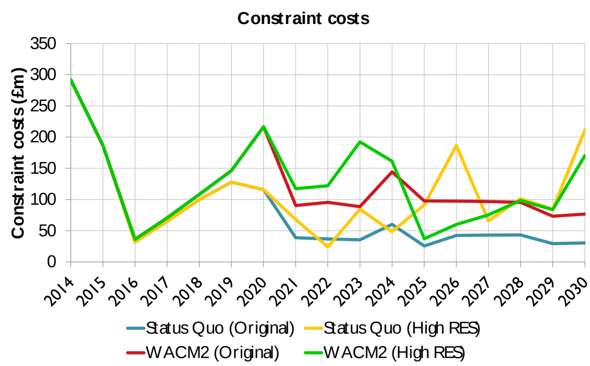
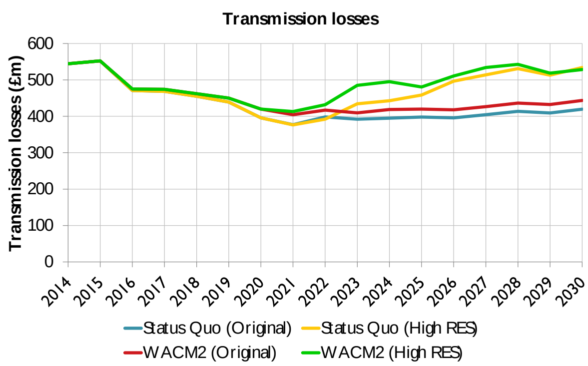


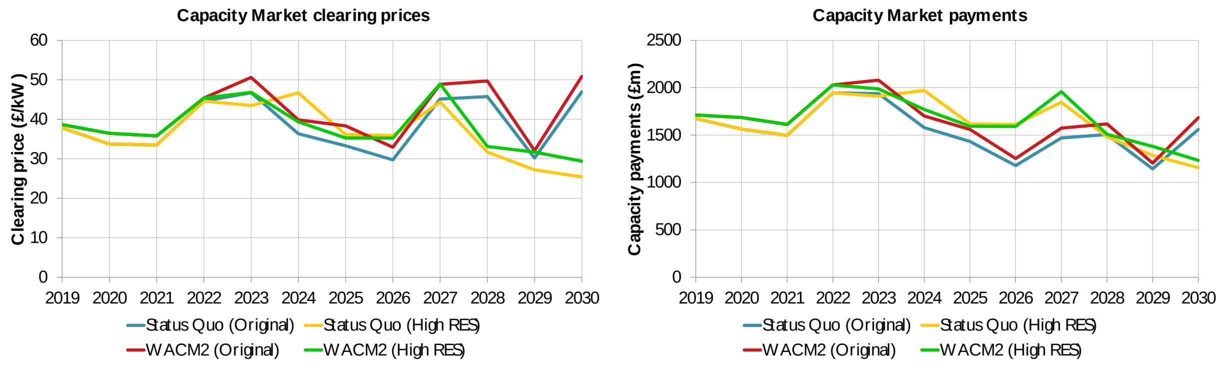

**Figure 36 Constraint costs and transmission losses – High RES**




CM clearing prices are still generally higher under WACM2 than Status Quo in the High RES Sensitivity but the differences are less systematic. This is equivalent to the observation seen in the Alternative Case, where a larger proportion of system capacity supported by CfDs reduces the dependency on and therefore relative cost impacts of the CM.

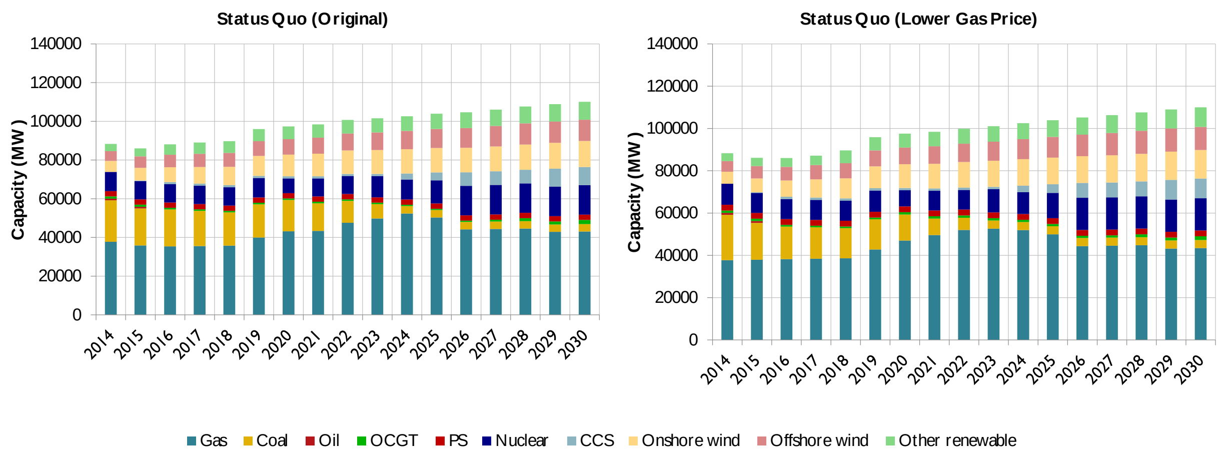
**Figure 37 Capacity Market clearing prices and payments – High RES**




***Lower Gas Price***

Counterintuitively, less new CCGT is built under Status Quo in the Lower Gas Price Sensitivity compared to the Original Case. However, this reduction in new build coincides with a reduction in the retirement of existing gas plant for a net increase in total CCGT capacity of about 400MW compared to the Original Case. Of this new capacity, a larger share is located in South England, replacing a greater capacity of coal plants that retire. WACM2 on the other hand has near identical levels of new build and retirements between the Lower Gas Price Sensitivity and the Original Case. This new capacity remains in North England and Midlands, creating greater locational variation to Status Quo in the Lower Gas Price Sensitivity compared to the Original Case. Thus the combination of lower gas prices and WACM2 does not encourage greater retention or build of CCGT capacity; rather it serves to emphasise locational differences with Status Quo. Differences in low load factor OCGT are also emphasised in the Lower Gas Sensitivity, with less Status Quo OCGT build and more WACM2 OCGT build compared to the Original Case, with changes primarily taking place in South England. There is little to distinguish the renewable build and location profiles of the Lower Gas Price Sensitivity and the Original Case.

**Figure 38 Generation capacity – Original Case and Lower Gas Price Sensitivity**




There is a greater near term dip in de-rated capacity observed in the Lower Gas Price Sensitivity compared to the Original Case. This is on account of larger volumes of coal retirements, which in the Original Case were receiving CM agreements in 2019 and thus staying open in the interim.

**Figure 39 De-rated capacity margins – Lower Gas Price**

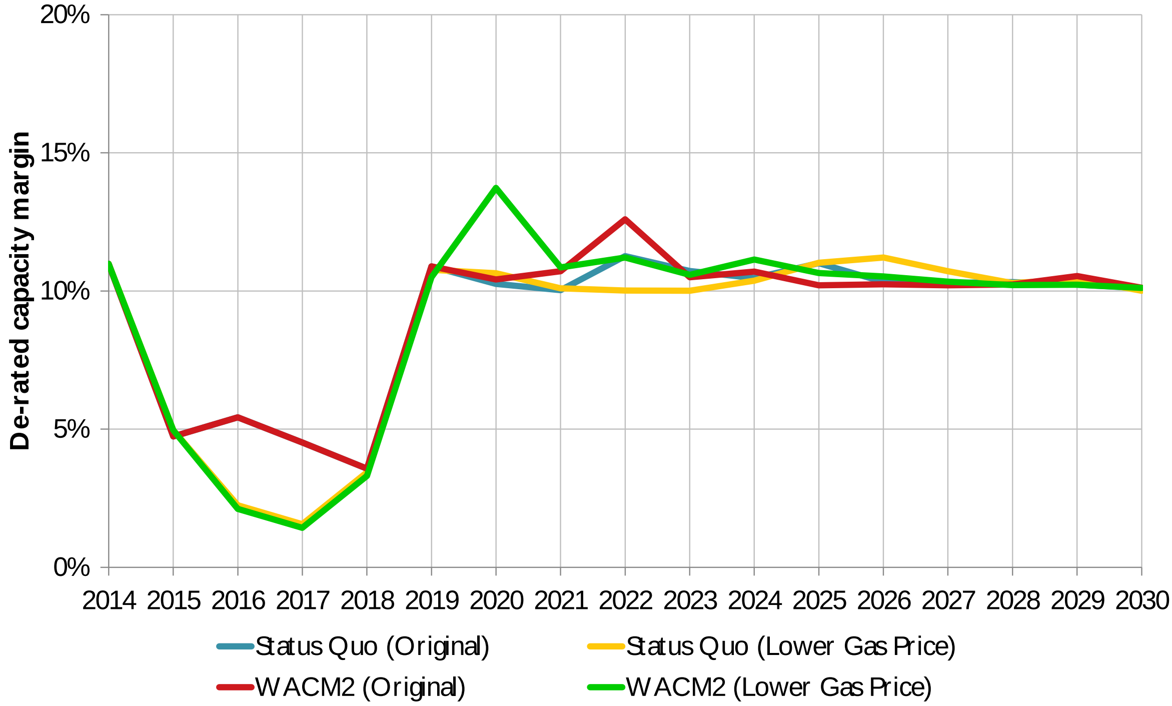
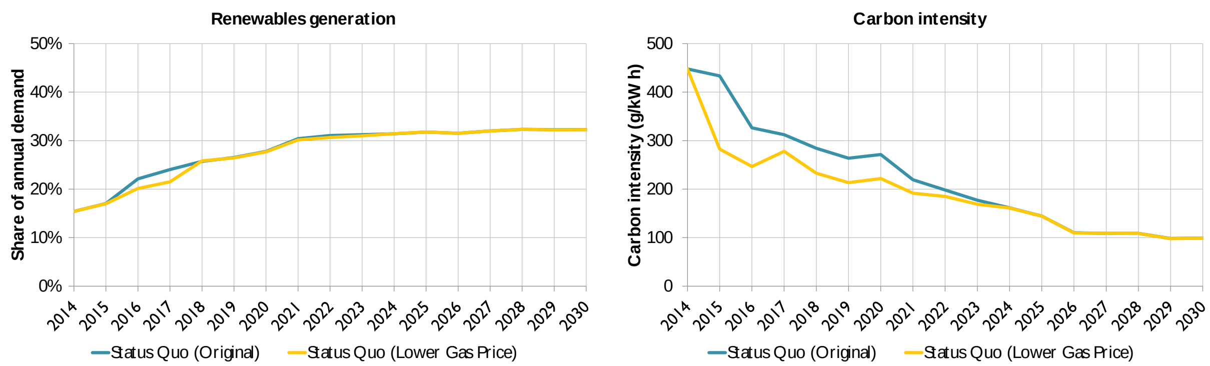



**Figure 40 Sustainability metrics – Lower Gas Price**




The combined effect of all capacity changes (location of retirements and new build) is that there is a net migration of capacity south under WACM2 in the Lower Gas Price Sensitivity compared to the Original Case. With a proportionally larger volume of capacity located south, there is a commensurate reduction in constraints costs.

**Figure 41** **Reinforcement costs to the main interconnected transmission system – Lower Gas Price**

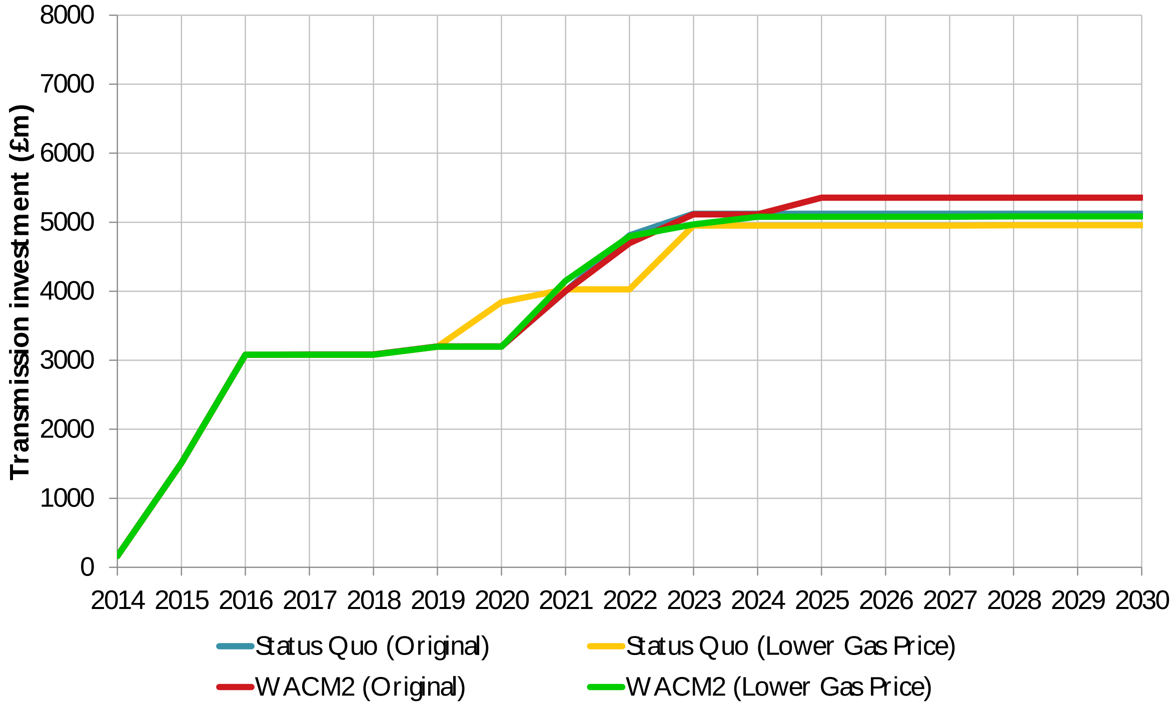



**Figure 42** **Constraint costs and transmission losses – Lower Gas Price**

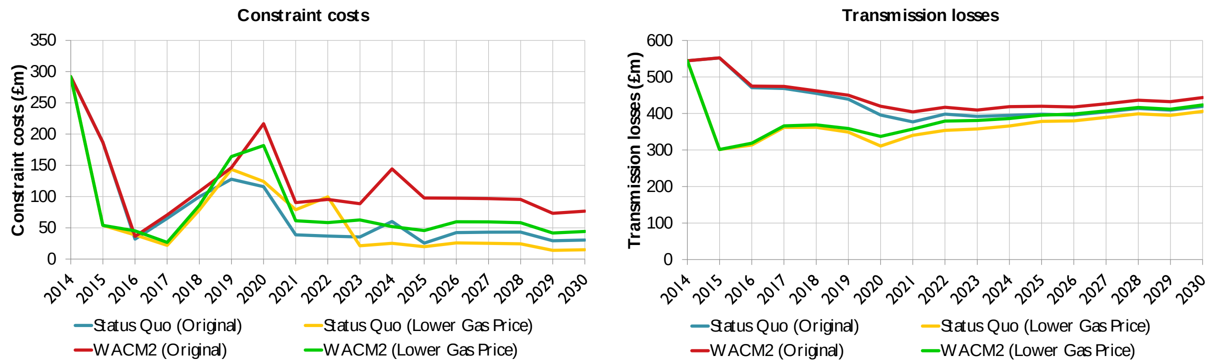
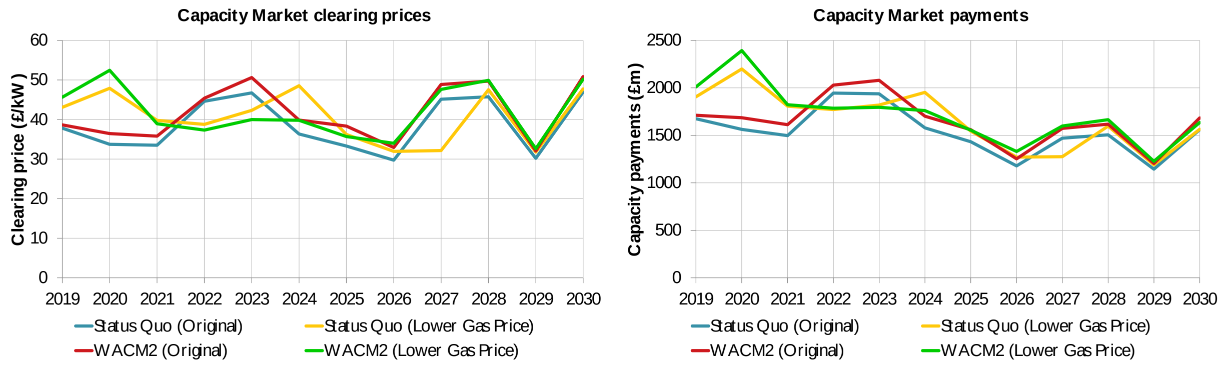


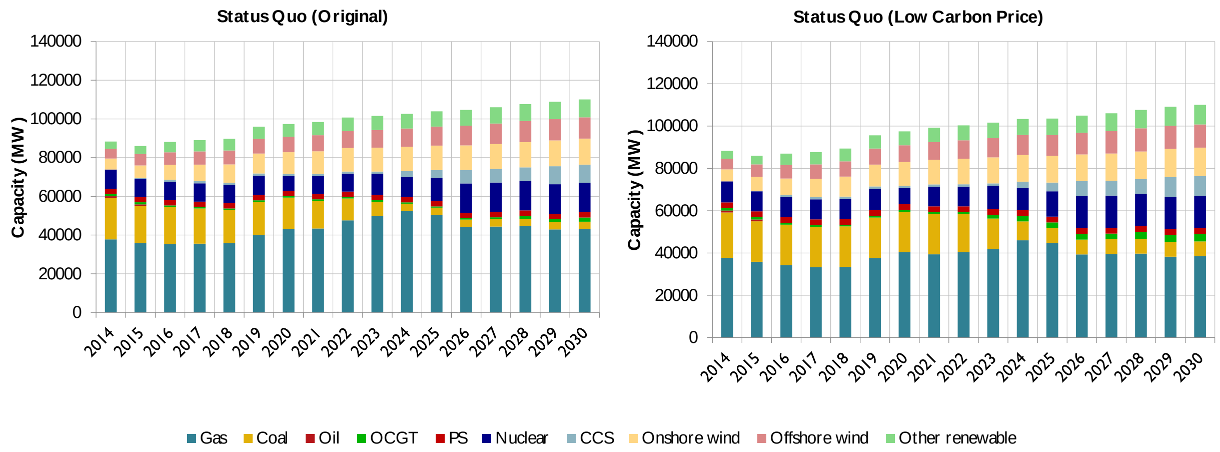
**Figure 43 Capacity Market clearing prices and payments – Lower Gas Price**




### *Low Carbon Price*

The prospects for coal improve significantly under this sensitivity. By 2030, there is 4,400MW less new gas capacity on the system in the Low Carbon Price Sensitivity than the Original Case. This is because fewer coal retirements and higher load factors reduce the need for new gas capacity. Under WACM2 we observe equivalent volumes of new CCGT build to Status Quo with similar northern migration as observed in the Original Case. Although less CCGT capacity is built, an additional 1,400MW of new OCGT build takes place in the Low Carbon Price Sensitivity compared to the Original Case indicating that the presence of coal favours a proportionally higher capacity of low load factor gas.

**Figure 44 Generation capacity – Original Case and Low Carbon Price Sensitivity**




There is a greater near term dip in de-rated capacity observed in the Low Carbon Price Sensitivity compared to the Original Case. This is on account of gas generators being forced out of merit and retiring earlier due to the higher load factors of coal plants.

**Figure 45 De-rated capacity margins – Low Carbon Price**

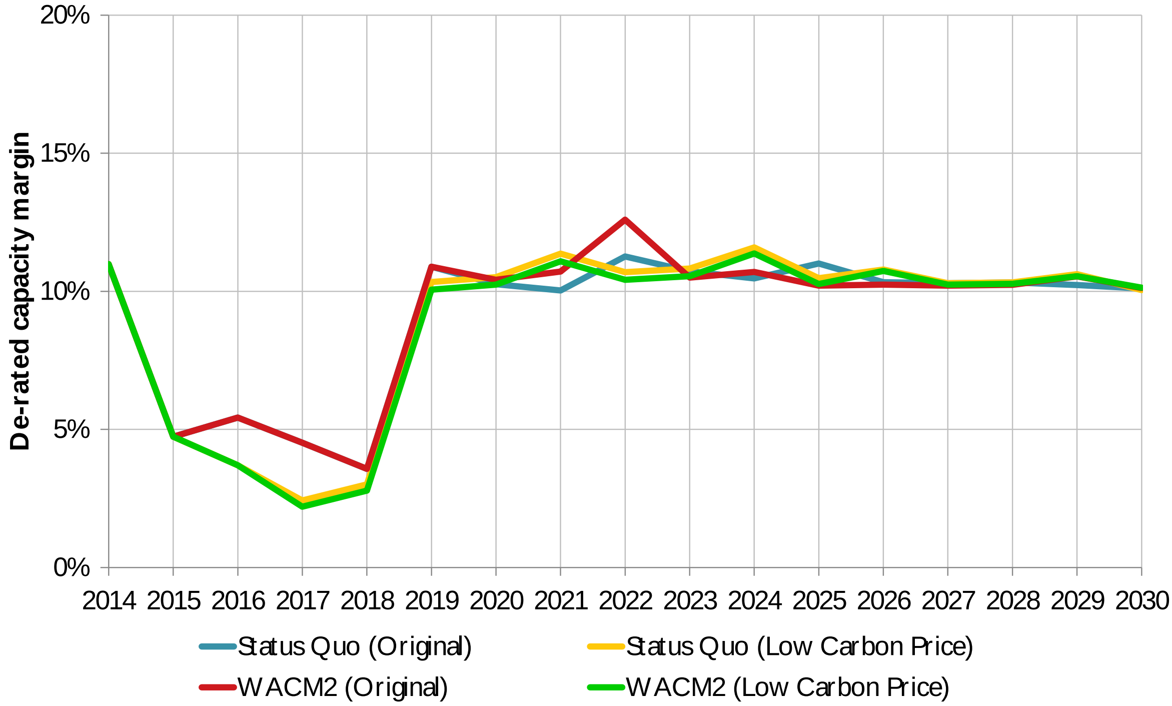
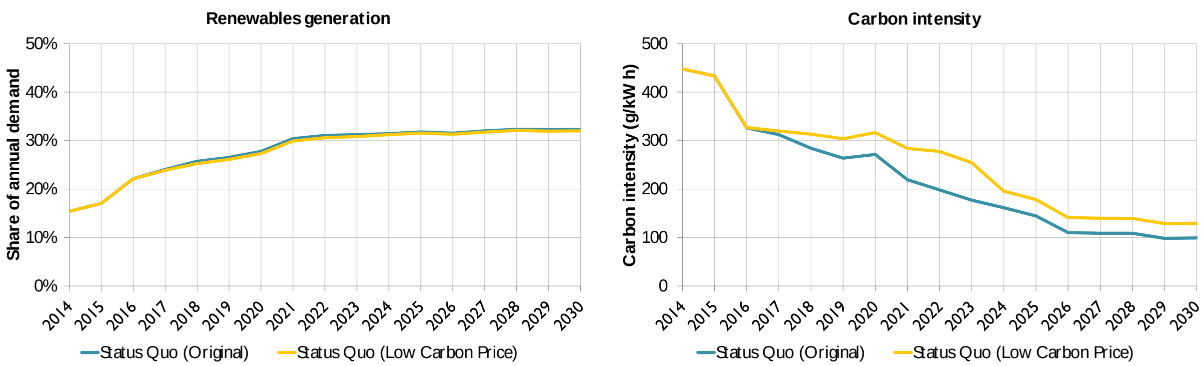



**Figure 46 Sustainability metrics – Low Carbon Price**




With increased retention of coal capacity, a greater proportion of generators are located in South England, Midlands and Wales under the Low Carbon Price Sensitivity. This lower the evolution of transmission costs, constraint costs and transmission losses. For instance, Eastern HVDC Link #2 is deferred to 2025 under Status Quo compared to a 2021 commissioning in the Original Case Status Quo.

**Figure 47 Reinforcement costs to the main interconnected transmission system – Low Carbon Price**

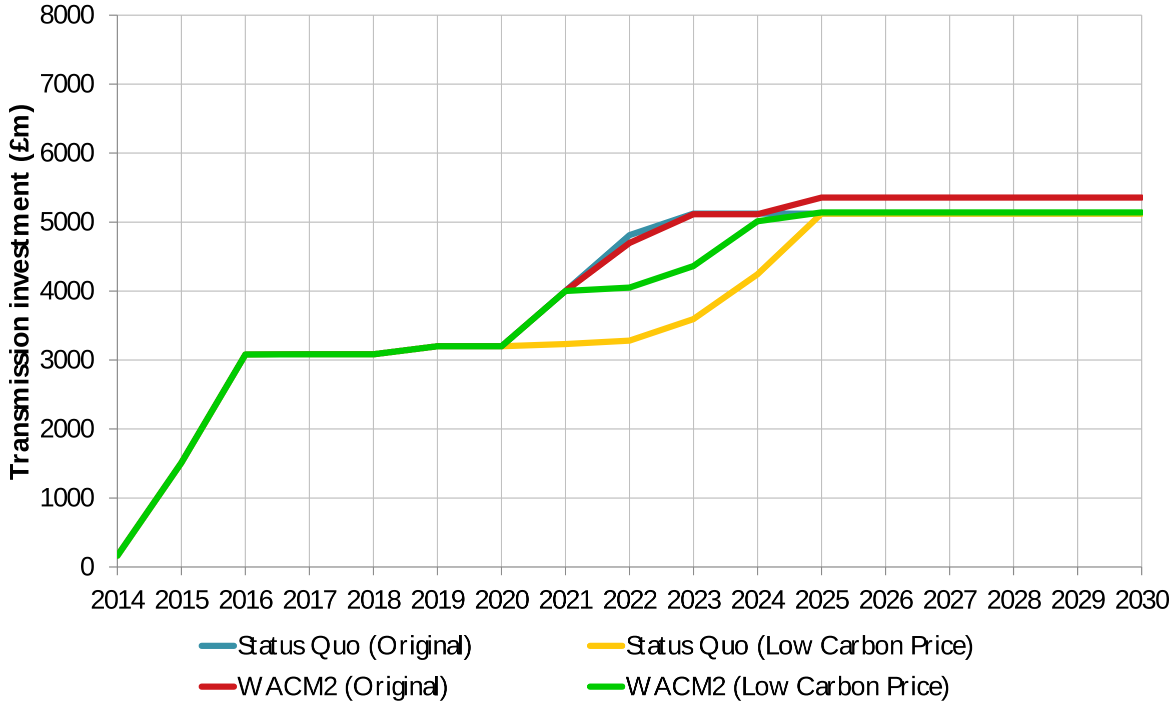



**Figure 48 Constraint costs and transmission losses – Low Carbon Price**

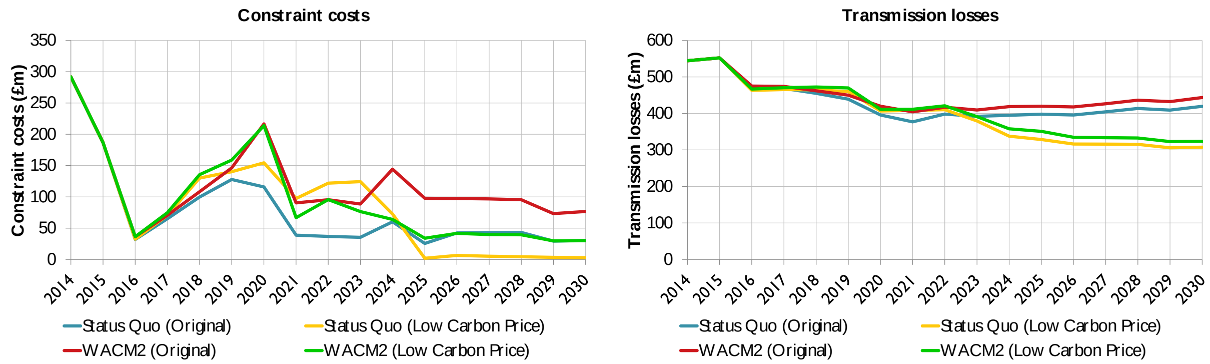
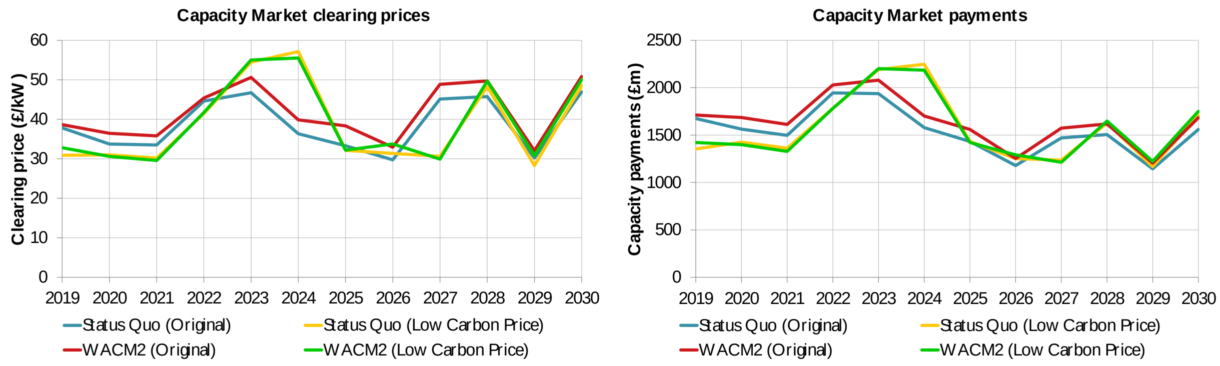


**Figure 49 Capacity Market clearing prices and payments – Low Carbon Price**




***7% Target De-rated Capacity Margin***

With a lower target margin from 2019 onwards, there are greater near term retirements prior to the introduction of the CM in the 7% Target De-rated Capacity Margin Sensitivity compared to the Original Case. Interestingly, this results in greater new build volumes as the increase in retirements (in de-rated capacity margin terms) is greater than the 3% decrease in target margin, creating a relative shortfall in capacity. Of this additional capacity, a greater proportion is built north under Status Quo compared to WACM2. The larger proportion of capacity in southern regions results in lower constraints costs under WACM2 in the 7% Target De-rated Capacity Margin Sensitivity compared to Original Case.

Renewable build volumes and location are identical to the Original Case, recognising that the system margin does not directly affect the outcomes of a fixed volume competitive allocation. Changes in tariffs on account of the changed capacity (and gross) margins and thermal build decisions are not significant enough to influence the merit order of wind decisions.

**Figure 50 Generation capacity – Original Case and 7% Target De-rated Capacity Margin Sensitivity**

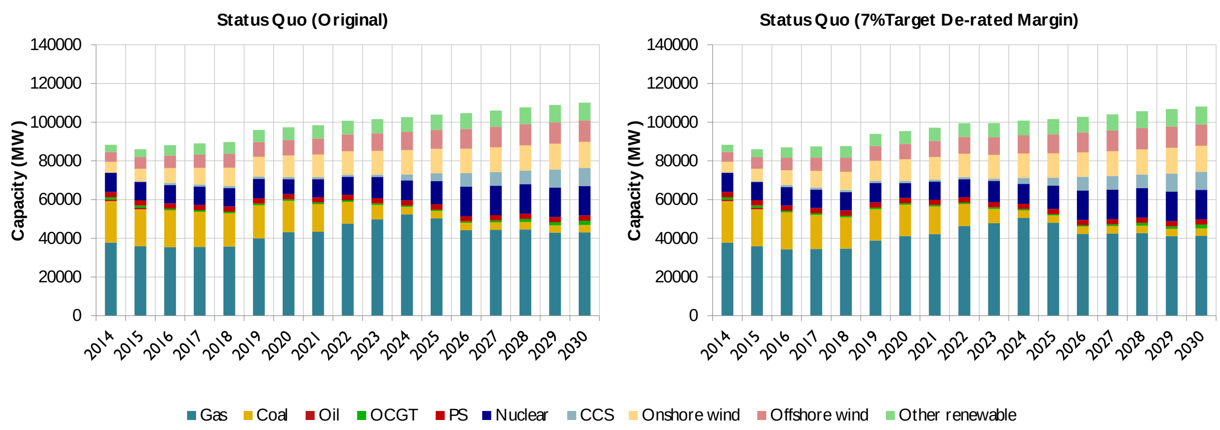


**Figure 51 De-rated capacity margins – 7% Target De-rated Capacity Margin**

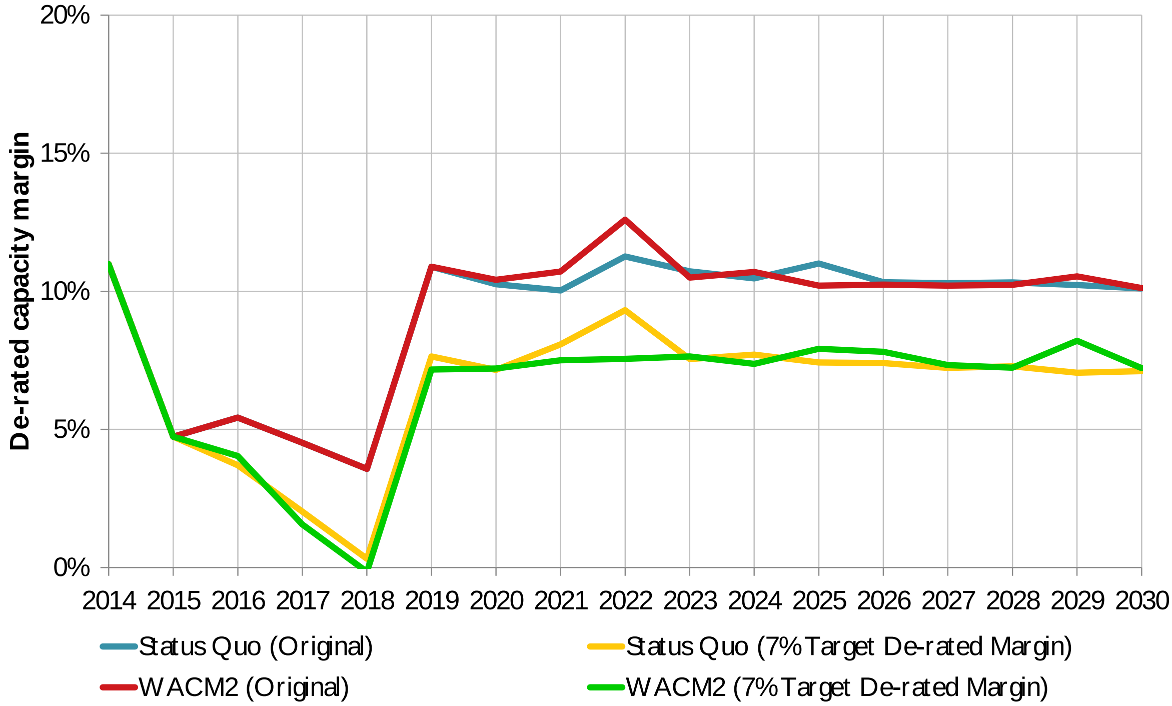
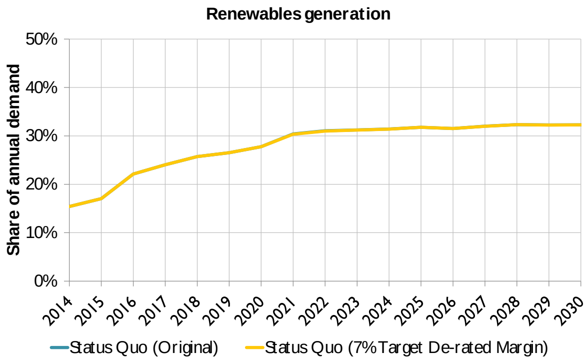



**Figure 52 Sustainability metrics – 7% Target De-rated Capacity Margin**



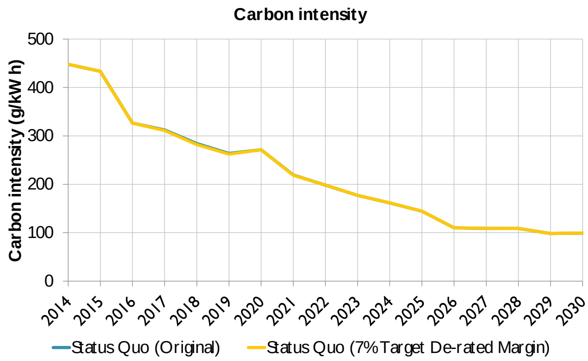



**Figure 53 Reinforcement costs to the main interconnected transmission system – 7% Target De-rated Capacity Margin**

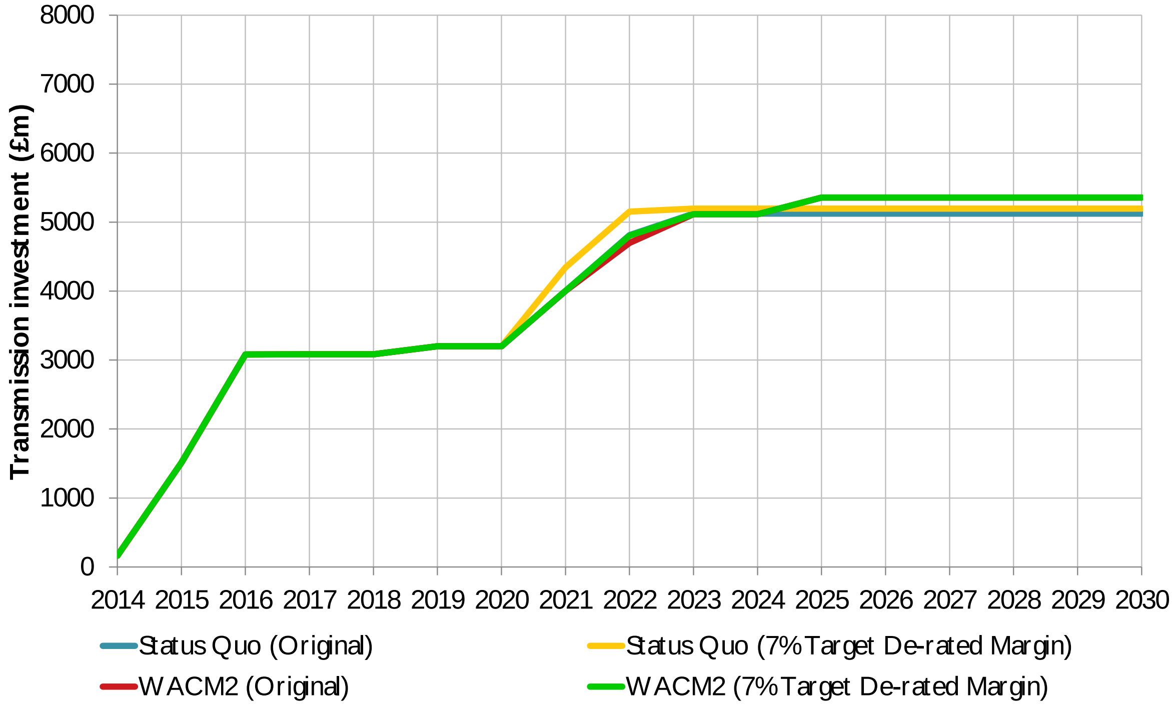
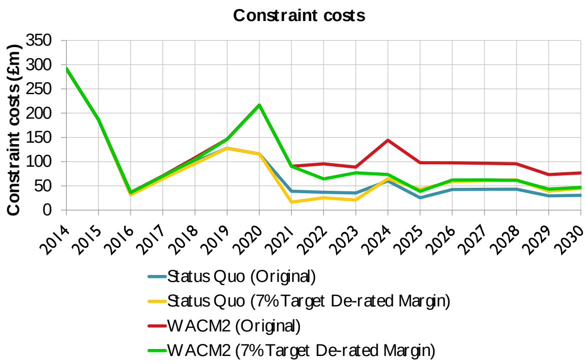
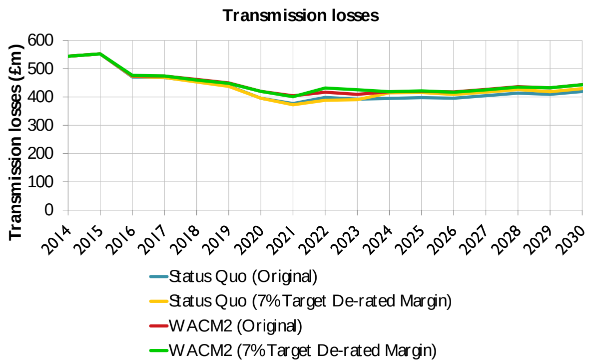


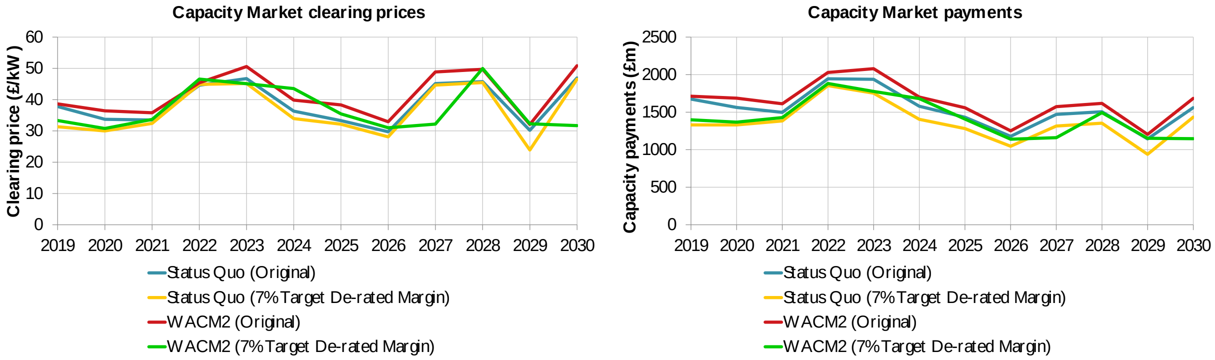

**Figure 54 Constraint costs and transmission losses – 7% Target De-rated Capacity Margin**




The lower target margin of this sensitivity results in lower CM auction clearing prices than in the Original Case. As in the Alternative Case, this reduces the upward impact of WACM2 on capacity prices, and thus the benefit from lower CfD strike prices is not eroded to the same extent as in the Original Case.

**Figure 55 Capacity Market clearing prices and payments – 7% Target De-rated Capacity Margin**




# A.2 Dispatch Distortion

***Methodology***

The Dispatch Distortion analysis seeks to understand what impact WACM2 might have on the dispatch decisions of generators, under the assumption that they take account of future TNUoS charges in their short run marginal costs (SRMCs). Under WACM2, the Year Round Shared (YRS) element of the tariff is multiplied by the annual load factor (ALF), which is derived from an average of load factors from the previous 5 years (after discarding the highest and lowest load factor years). Therefore, in theory, generators are aware that running today incurs a cost in the future (if YRS is positive).

We have determined the impact on SRMC under WACM2 as follows:

- Using the YRS portion of the tariff in each zone, work out the impact on individual generator SRMCs as the additional cost of a 1 hour increase in assumed load factor; and
- Divide by 5 as an increase in one year only affects the average in the following years in a 1/5 ratio. For each year, take the NPV of the next 5 years. This is the discounted impact on future tariffs of a 1 hour increase in the current year.

We assume that generators have perfect foresight of five years of future YRS tariffs. We further assume that generators have no foresight of which years will have above or below average load factors. Therefore all years are treated equally, even though some of them will be excluded for being the highest or lowest load factor in a 5 year period (and the remaining 3 will increase in weighting).

Only the generation dispatch is re-run with the above changes. This affects market prices, transmission losses and constraints. All generation decisions, transmission decisions, tariffs and capacity payments remain unchanged. Therefore, these results do not represent a full sensitivity. There may be knock-on impacts on generation decisions, transmission decisions or tariffs which are not captured in this analysis.

The load factors of plants will change, with plants that are seemingly cheaper on account of the change running more. These generators are not truly cheaper however, so generation costs can be expected to increase. Prices may increase or decrease depending on the identity of the marginal generator.

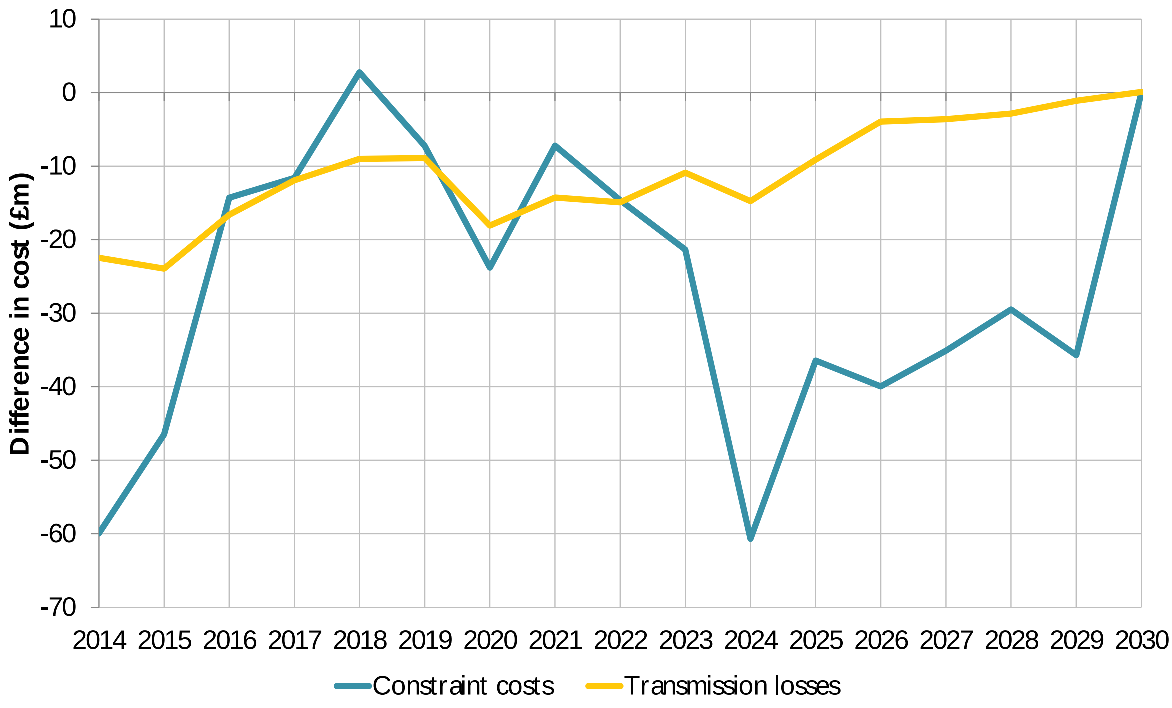
Note that Dispatch Distortion analysis was made on the Original Case only.

***Results***

The changes in SRMC in 2020 observed range from -£0.44/MWh to +£0.57/MWh. On average, CCGT SRMCs increase by £0.01/MWh and coal SRMCs increase by £0.03/MWh. Prices decrease by an average of £0.05/MWh across the period of analysis, as a result of the ability of the model to select plant which have seen their SRMC reduce.

A further impact of the distortion is to reduce generation in the north by replacing it with southern generation and an increase in interconnector imports. This serves to reduce both the constraint costs and the cost of local transmission losses (see Figure 56).

**Figure 56 Difference in constraint costs and transmission losses between WACM2 and WACM2 with Dispatch Distortion – Original Case**




***Cost Benefit Analysis***

Table 21 indicates the impact on the CBA of the Dispatch Distortion analysis with respect to the incremental impact on WACM2. The incremental impact of Dispatch Distortion to WACM2 is to increase the sum of the generation costs and carbon costs by £17m to 2020 and £4m between 2021 and 2030. Savings in constraint costs and transmission losses are much larger. These savings are passed through to consumers[61], leading to a saving due to this apparent distortion.

[61] Note that capacity payments have not been recalculated and can be expected to increase with Dispatch Distortion due to the lower wholesale prices.

Table 21 Cost Benefit Analysis – Dispatch Distortion – Original Case

| Incremental impact of Dispatch Distortion on WACM2 NPV (£m) | | 2011-20 | 2021-30 |
|---|---|---|---|
| Power sector costs | Generation costs | 107 | 32 |
| | Transmission costs | 89 | 47 |
| | Constraint costs | 132 | 164 |
| | Carbon costs | -125 | -36 |
| | **Decrease in power sector costs** | **204** | **208** |
| | | | |
| Consumer bills | Wholesale costs (including capacity payments) | 120 | 58 |
| | BSUoS | 66 | 82 |
| | Transmission losses | 89 | 47 |
| | Demand TNUoS charges | 0 | 0 |
| | Low carbon support | -5 | -4 |
| | **Decrease in consumer bills** | **270** | **183** |

Consumers see a saving with Dispatch Distortion because prices go down. Part of this decrease is a Balancing System Use of System (BSUoS) charge saving but there is also a saving in underlying wholesale costs. There is a small offsetting increase in CfD payments (which is captured). There is also the potential for a small increase in capacity payments which is not captured in this analysis.

We find that applying Dispatch Distortion to WACM2 happens to distort SRMCs in a way that aligns with the signals that would be required to reduce constraint costs and transmission losses. However, it is not a given that generators would attempt to reflect these costs in dispatch, given that there is a risk of predicting future tariff incorrectly.

## A.3 Impact of interconnectors on CM payments in Alternative Case

In the Alternative Case, interconnected capacity is assumed to provide a level of security to GB which is equivalent to 75% of the total interconnector capacity (which equates to 3 GW in 2014, rising to 6.7 GW in 2030). In the modelled Capacity Market, this reduces the de-rated capacity required from domestic capacity by the same amount. We have assumed that interconnected capacity does not participate directly in the Capacity Market, and does not receive capacity payments.

In this we explore the potential impact on the Alternative Case of participation of interconnected capacity in the CM[62]. Although interconnectors will not participate in the first capacity auction, DECC has expressed an intention to consider ways in which interconnection might participate in later auctions.

[62] In the Original Case, interconnectors are not assumed to contribute to the required capacity in the CM (they have a de-rating factor of 0%), and therefore this analysis is not relevant.

For the purposes of this analysis, we assume that the volume that interconnectors/interconnected capacity can offer into the market is limited by the assumed 75% de-rating factor.

The prices for GB generators are modelled on a perfectly competitive cost recovery basis. We have not attempted to derive prices on this basis for interconnected capacity, since we do not know the identity of this capacity. Instead, we consider three cases for the price at which interconnected capacity could offer into the capacity auction.

***1. Interconnected capacity offers a lower price than marginal GB capacity***

In this case, we assume that interconnected capacity participates and always clears within the auction, but is never the marginal capacity. The interconnected capacity receives the current GB capacity price in each year. This would increase GB capacity payments by about £868m under SQ and £910mn under WACM2 (NPV terms, 2011-2030) – a difference of £42m. The impact on the capacity payments line of the CBA is presented in Table 22.

**Table 22 Impact on Capacity Payments (Alternative Case, interconnector adjustment 1)**

| WACM2 benefit relative to Status Quo | Alternative Case | | Alternative Case (interconnectors paid) | |
|---|---|---|---|---|
| NPV (£m) | 2011-20 | 2021-30 | 2011-20 | 2021-30 |
| Capacity payments | -13 | -213 | -15 | -252 |

***2. Interconnected capacity offers a higher price than marginal GB capacity***

In this case, interconnected capacity offers into the auction, but is always out of merit and does not receive a capacity agreement. The interconnected capacity therefore receives no capacity payment. There are two possible variants depending on how the interconnected capacity is treated with respect to its contribution to security of supply:

1. Interconnected capacity is not procured and therefore the required domestic capacity increases. For the purposes of modelling, this would be equivalent to assuming that interconnectors do not contribute to GB security of supply (i.e. a de-rating factor is 0%, as for the Original Case). Additional GB capacity would be required, and it is likely that capacity payments would be higher throughout the period. (However, this would require a sensitivity to be modelled). In this case, the difference between WACM2 and SQ in capacity payments is likely to be larger than in the Alternative Case.
2. Interconnected capacity is not procured but is still assumed to contribute to security of supply. In this case, results would be identical to the modelled Alternative Case.

***3. Interconnected capacity is on the margin***

In this case, we assume that interconnectors are always on the margin and set the clearing price. It is difficult to see how this case might evolve since the clearing prices in the auction vary each year (between 0 and 40 £/kW). If this did occur then capacity auction clearing prices would not be affected by WACM2 (since interconnected capacity does not pay TNUoS) and the cost of the Capacity Market would be identical between the two charging options.

In outturn, interconnectors could be marginal in some years and not in others, so it is unlikely that all differences in capacity payments between SQ and WACM2 would be removed. If interconnected capacity was marginal in certain years, additional GB capacity might be required which would change other aspects of the CBA including power sector costs. It is therefore difficult to say with any certainty what the impact might be. The potential impact on the capacity payment line of the CBA is shown in Table 23.

**Table 23 Impact on Capacity Payments (Alternative Case, interconnector adjustment 3)**

| WACM2 benefit relative to Status Quo | Alternative Case | | Alternative Case (interconnectors marginal) | |
|---|---|---|---|---|
| NPV (£m) | 2011-20 | 2021-30 | 2011-20 | 2021-30 |
| Capacity payments | -13 | -213 | -13 to 0 | -213 to 0 |

***Conclusions***

This additional analysis demonstrates the uncertainty introduced by the treatment of interconnection under the CM. The impact on consumer costs could be a £42m dis-benefit under WACM2 (if interconnectors are paid the same price as other capacity, but do not affect the price), or a decrease in cost differences, which is harder to quantify, if interconnectors are marginal.

We have not made any assumptions regarding potential increases in Demand Side Response, storage, or embedded generation. These sources of capacity would also not be exposed to TNUoS either, and similar arguments apply in terms of potentially reducing capacity payment differences between SQ and WACM2.

# B Review of Additional NERA/ICL analysis

The NERA/ICL analysis of a simplified system in Appendix B of the IA review shows that WACM2 does not always reflect the SQSS economic criterion. Leaving aside whether this is the correct comparison to make, the major omission here is that Status Quo tariffs are not included. Without a comparison, it is not possible to say which option better furthers the relevant objectives. NERA/ICL have constructed a simple system, with ACS demand of 60,000 MW and a generation mix shown in Table 24.

**Table 24 Example system**

| | Node | TEC (MW) |
|---|---|---|
| Wind farm | 1 | 10000 |
| Conventional | 1 | 10000 |
| Conventional | 2 | 40000 |
| Peaking | 2 | 10000 |
| Nuclear | 2 | 10000 |

We first note that the SQSS economic criterion is only a guide to be representative under a full CBA. It is not possible to tell from this simple example whether under a full CBA approach Transmission Owners (TOs) would invest in more or less. Given that this analysis ignores the CBA approach, the relevance of this analysis is low.

To calculate WACM2 tariffs, NERA/ICL make some simplifying assumptions. They assume that the G:D split is 100:0. This is in turn making implicit assumptions about MAR (i.e. the costs of the existing transmission system that need to be recovered). Given that the absolute level of tariffs may be higher or lower depending on the outturn value of the residual tariff, it is only relevant to consider the differentials between the tariffs for different plant types and in different locations. We note that the residual itself would vary in NERA/ICL's examples as the outturn tariffs recover a different total amount (due both to the different tariffs and the different capacity mix).

We also note that it assumes no adjustments for system security which exist in the SQSS. The assumption of a security factor of 1.0 is reasonable for this simple unsecured and non-meshed system. This is a multiplier to the reinforcement cost so we assume that if a factor of 1.8 were used it would increase both the marginal reinforcement cost and the tariffs, and therefore should not change the conclusions.

For NERA/ICL's example, we have added the missing calculation of the cost reflectivity of Status Quo tariffs in this example (since the comparison between Status Quo and WACM2 is what is important for the purposes of Ofgem's determination on CMP213).

**Table 25 Incremental cost based on SQSS, compared to WACM2 and Status Quo tariffs**

| Node | Technology | Incremental cost (£/kW) | | | | WACM2 (£/kW) | | | | Status Quo (£/kW ) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **40%** | **50%** | **60%** | **100%** | **40%** | **50%** | **60%** | **100%** | **All** |
| 1 | Wind farm | 2.15 | 2.24 | 2.33 | 2.8 | 1 | 1 | 1.6 | 4 | 4 |
| 1 | Conventional | 2.72 | 2.85 | 2.99 | 3.75 | 2.8 | 2.8 | 3.04 | 4 | 4 |
| 2 | Conventional | 0.14 | 0.12 | 0.1 | 0 | 1 | 1 | 1 | 1 | 1 |
| 2 | Peaking | 0.14 | 0.12 | 0.1 | 0 | 1 | 1 | 1 | 1 | 1 |
| 2 | Nuclear | 0.14 | 0.12 | 0.1 | 0 | 1 | 1 | 1 | 1 | 1 |

WACM2 takes account of the increasing impact of low carbon generation on the system as the proportion increases, whereas Status Quo does not. Status Quo takes no account of load factor and does not vary with reinforcement cost. WACM2 and Status Quo have invariant values for plant on node 2 in this example. Therefore there is no difference in cost reflectivity on this node.

It is our view that the results for Status Quo are less cost reflective than those for WACM2, although WACM2 does not totally reflect the SQSS. Given that this analysis ignores the CBA approach, the relevance of this analysis is low.

As NERA/ICL note, investments by the TOs may be triggered either by the SQSS backgrounds or by a full CBA. Therefore these examples are more useful to illustrate the relationships between these points than to draw firm conclusions about the cost reflectivity of Status Quo and WACM2.